

**BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION
NASHVILLE, TENNESSEE**

IN RE:

ATMOS ENERGY CORPORATION	)	
TENNESSEE DIRECT,	)	
KENTUCKY/MID-STATES DIVISION,	)	Docket No. 23-00050
AND SHARED SERVICES UNIT	)	
DEPRECIATION STUDY	)	

NOTICE OF FILING COMMISSION ORDERS FROM OTHER JURISDICTIONS

In footnotes 7 through 20 on page 16 of his pre-filed rebuttal testimony, Mr. Ned Allis provided citations to various Orders from other jurisdictions which are relevant to his testimony. In the interest of assisting the Commission and Staff in conveniently reviewing and evaluating Mr. Allis's testimony, Atmos Energy hereby gives notice of the filing of copies of those Orders. For ease of reference, these Orders are attached to this Notice in the same order as they are cited in Mr. Allis's pre-filed rebuttal testimony. In addition, each Order has been separately bookmarked.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served, via the method(s) indicated below, on the following counsel of record, this the 19th day of October, 2023.

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173 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and James P. Danly.

Pacific Gas and Electric Company

Docket No. ER16-2320-002

OPINION NO. 572

ORDER ON INITIAL DECISION

(Issued October 15, 2020)

Table of Contents

I.	Background.....	- 3 -
II.	Discussion	- 4 -
A.	Determining the ROE	- 5 -
1.	Initial Decision.....	- 5 -
2.	Briefs on Exceptions	- 8 -
3.	Briefs Opposing Exceptions	- 11 -
4.	Commission Determination	- 12 -
B.	Cost of Long-Term Debt.....	- 15 -
1.	Reasonableness of Forecasted Cost of Debt	- 15 -
2.	Use of Net Proceeds to Calculate Long-Term Debt Costs	- 20 -
3.	Remaining Issues	- 23 -
C.	Capital Structure	- 25 -
1.	Initial Decision.....	- 25 -
2.	Briefs on Exceptions	- 26 -
3.	Briefs Opposing Exceptions	- 27 -
4.	Commission Determination	- 27 -
D.	Depreciation Rates	- 28 -

1. Average Remaining Service Lives and Dispersion Patterns (i.e., Iowa Curves).....	- 29 -
2. Net Salvage and Cost of Removal Ratios.....	- 55 -
E. Capital Additions	- 68 -
1. Capital Additions Forecast.....	- 68 -
2. Inclusion of Allegedly Imprudent Capital Costs	- 76 -
F. Allocating Common, General and Intangible (CGI) Plant Costs.....	- 87 -
1. Initial Decision.....	- 88 -
2. Briefs on Exceptions	- 91 -
3. Briefs Opposing Exceptions	- 93 -
4. Commission Determination	- 94 -
G. O&M Expense Forecast.....	- 96 -
1. Initial Decision.....	- 96 -
2. Briefs on Exceptions	- 98 -
3. Briefs Opposing Exceptions	- 99 -
4. Commission Determination	- 100 -
H. A&G Expenses.....	- 101 -
1. Initial Decision.....	- 102 -
2. Briefs on Exceptions	- 104 -
3. Briefs Opposing Exceptions	- 106 -
4. Commission Determination	- 107 -
I. Allocators	- 107 -
1. Initial Decision.....	- 108 -
2. Brief on Exceptions.....	- 110 -
3. Briefs Opposing Exceptions	- 110 -
4. Commission Determination	- 111 -
J. Sales Forecast	- 112 -
1. Initial Decision.....	- 112 -
2. Briefs on Exceptions	- 116 -
3. Briefs Opposing Exceptions	- 118 -
4. Commission Determination	- 119 -
K. Miscellaneous Issues.....	- 121 -

1. Inclusion of Certain Non-Capital Items.....	- 121 -
2. Prepaid Expenses That Should Not be Included in Rate Base	- 132 -
3. Forecast of Non-Tariffed New Products and Services (NP&S) Expenses and Revenue	- 134 -
4. Income Tax and ADIT Costs Resulting From the Tax Cuts and Jobs Act...	- 138 -
III. Conclusion.....	- 142 -

1. This case is before the Commission on exceptions to the October 1, 2018 Initial Decision issued in the above-captioned proceeding.¹ The central issue before the Commission is whether the rates proposed by Pacific Gas and Electric Company (PG&E) in its eighteenth revised transmission owner tariff (TO18) filing are just and reasonable and not unduly discriminatory or preferential. In this order, we reverse in part and affirm in part the Initial Decision, as discussed herein. We also direct further briefing regarding PG&E's return on equity (ROE). Initial briefs shall be due 60 days from the date of this order. Responses to those initial briefs shall be due 30 days later. No answers or additional briefs will be permitted. Finally, we direct PG&E to recalculate its TO18 rates in accordance with the directives in this order and the future order on the ROE issue and to submit the revised TO18 rates within 60 days of the Commission order on the ROE issue discussed below.

I. Background

2. On July 29, 2016, PG&E submitted its TO18 filing, pursuant to section 205 of the Federal Power Act (FPA),² to request an increase to its stated transmission rates. PG&E's filing and the parties' protests and answers are summarized in the TO18 Order.³ As relevant here, the Commission accepted for filing PG&E's TO18 rates, suspended them for five months to become effective on March 1, 2017, subject to refund, and established hearing and settlement judge procedures.⁴ The Commission held the hearing

¹ *Pac. Gas & Elec. Co.*, 165 FERC ¶ 63,001 (2018) (Initial Decision).

² 16 U.S.C. § 824d.

³ *Pac. Gas & Elec. Co.*, 156 FERC ¶ 61,238, at PP 2-8, 11-26 (2016) (TO18 Order).

⁴ TO18 Order, 156 FERC ¶ 61,238 at PP 1, 29-36. PG&E subsequently filed its proposed nineteenth revised transmission owner tariff (TO19) filing on July 27, 2017. The Commission accepted PG&E's filing, suspended it for five months, and established hearing and settlement judge procedures. *Pac. Gas & Elec. Co.*, 160 FERC ¶ 61,128 (2017). PG&E's TO19 rates became effective on March 1, 2018, and therefore, the

in abeyance to provide parties with an opportunity to settle the matter, but on March 17, 2017, settlement discussions were terminated and a trial-type evidentiary hearing ensued.⁵

3. On October 1, 2018, the Presiding Administrative Law Judge (Presiding Judge) issued the Initial Decision, which is summarized in greater detail below. On October 31, 2018, the California Public Utilities Commission (CPUC), Modesto Irrigation District (Modesto), the City of Santa Clara, California and M-S-R Public Power (together, Santa Clara/MSR), the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (together, Six Cities), Transmission Agency of Northern California (TANC), Commission Trial Staff (Trial Staff), and PG&E filed briefs on exceptions to the Initial Decision.⁶ On November 20, 2018, California Department of Water Resources State Water Project (SWP), CPUC, Six Cities, TANC, Trial Staff, and PG&E filed briefs opposing exceptions.

II. Discussion

4. The Presiding Judge made determinations with respect to 11 major categories of PG&E's costs of service: (A) ROE; (B) Cost of Long-Term Debt; (C) Capital Structure; (D) Depreciation Rates; (E) Capital Additions; (F) Allocating Common, General and Intangible (CGI) Plant Costs; (G) Operation and Maintenance (O&M) Expenses Forecast; (H) Administrative and General (A&G) Expenses; (I) Allocators; (J) Sales Forecast; and (K) Miscellaneous Issues. The Presiding Judge also noted that an additional issue, Escalation Factors, had been resolved by the parties,⁷ and we do not address it here. Except as otherwise discussed herein, the Commission affirms the Presiding Judge's findings of fact and conclusions of law, as discussed in the Initial Decision. We, however, reverse the Initial Decision on the following issues as discussed further below:

TO18 rates approved in this order will be effective for the period of March 1, 2017 through February 28, 2018.

⁵ See *Pac. Gas & Elec. Co.*, Docket No. ER16-2320-000, at P 1 (Mar. 17, 2017) (terminating settlement judge procedures, designating a presiding administrative law judge, and establishing a procedural schedule).

⁶ Sacramento Municipal Utility District (SMUD) filed a one-page, untimely brief on exceptions on November 5, 2018, which adopted TANC's and CPUC's briefs on exceptions.

⁷ Initial Decision, 165 FERC ¶ 63,001 at P 796. This issue involved PG&E's proposed escalation factors to develop the forecasts of materials and supplies expense components of its operation and maintenance expenses and administrative and general expenses.

(B) Cost of Long-Term Debt (in part); (D) Depreciation Rates (in part); and (L) Miscellaneous Issues (in part). As stated above, we direct further briefings on the ROE issue.

A. Determining the ROE

5. PG&E requested a base ROE of 10.4%, but no lower than 10.25%. To support this proposal, PG&E's witness assessed PG&E's cost of equity by (1) estimating the cost of equity values for other electric utilities with comparable risks to PG&E; and (2) considering the effects of current capital market conditions.⁸ Acknowledging the process outlined by the Commission in Opinion No. 531, PG&E applied a two-step discounted cash flow (DCF) model to determine a zone of reasonableness and then utilized other models to support the placement of a specific ROE value within that zone. According to PG&E, the results of the alternative models, as well as a survey of state-approved ROEs, indicate that the median values derived from the DCF method are too low to be considered reasonable. Therefore, PG&E proposed an ROE from the upper end of its calculated range. PG&E also requested a 50 basis point adder to recognize PG&E's participation in CAISO, which would bring PG&E's total ROE to 10.9%.⁹

1. Initial Decision

6. The Presiding Judge began his analysis by acknowledging that the Supreme Court set out the criteria for determining a just and reasonable ROE in *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*¹⁰ and *Federal Power Commission v. Hope Natural Gas Company*.¹¹ The Presiding Judge acknowledged that *Hope* requires that a utility's ROE be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."¹² Therefore, according to the Presiding Judge, an ROE that authorizes a utility to collect more than is necessary to satisfy *Hope* and *Bluefield* requirements exploits customers and is unjust and unreasonable.¹³

⁸ PG&E Filing, Ex. PGE-0014 (Testimony of Adrien M. McKenzie).

⁹ Ex. PGE-0014 at 6:19.

¹⁰ 262 U.S. 679, 692-93 (1923) (*Bluefield*).

¹¹ 320 U.S. 591, 603 (1944) (*Hope*).

¹² Initial Decision, 165 FERC ¶ 63,001 at P 45 (quoting *Hope*, 320 U.S. at 603).

¹³ *Id.* PP 10-11.

7. The Presiding Judge explained that the Commission uses the DCF to estimate the ROE necessary to attract equity investors. The Presiding Judge stated that this approach was set forth by the Commission in *Coakley v. Bangor Hydro-Electric Company*¹⁴ and in *Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*¹⁵ Although the Presiding Judge acknowledged the D.C. Circuit's decision in *Emera Maine*, he stated that the court's vacatur of Opinion No. 531 need not prevent the Commission from using the parts of Opinion No. 531 that the court found satisfactory as guideposts.

8. Therefore, consistent with the Commission's previously established DCF approach, the Presiding Judge explained that implementing the DCF model to determine a just and reasonable ROE involves several steps, including (1) selecting a proxy group of utilities; and (2) calculating the cost of equity for the utilities in that group, which includes calculating the expected growth rate. With regard to the proxy group, the Presiding Judge stated that the Commission prescribes five criteria for screening purposes.¹⁶ As relevant here, the Presiding Judge noted that Commission policy is that each utility included in the proxy group have a credit rating no more than one notch above or below PG&E's as listed by both S&P and Moody's. The Presiding Judge noted that no party disputed the inclusion of the following seven companies: (1) ALLETE; (2) Consolidated Edison; (3) Edison International; (4) OGE Energy Corp.; (5) PG&E Corp.; (6) Pinnacle West; and (7) WEC Energy Group. The Presiding Judge noted, however, that the parties to the proceeding each included additional companies that he ultimately excluded.

9. Next, the Presiding Judge considered the process by which the parties calculated costs of equity. The Presiding Judge observed that Six Cities and Trial Staff calculated the short-term growth rate for each of the proxy companies based on the five-year growth rate for each company forecasted by IBES, while PG&E used a composite forecast that included IBES, Zacks, Bloomberg, S&P Capital IQ, FactSet, and Value Line. The Presiding Judge rejected PG&E's composite forecast, stating that PG&E provided no Commission precedent that relied on the aforementioned companies. Additionally, the

¹⁴ Opinion No. 531, 147 FERC ¶ 61,234 (Opinion No. 531), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014) (Opinion No. 531-A), *order on reh'g*, 150 FERC ¶ 61,165, Opinion No. 531-B, (2015), *vacated*, *Emera Me. v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*).

¹⁵ Opinion No. 551, 156 FERC ¶ 61,234 (2016) (Opinion No. 551).

¹⁶ Opinion No. 551, 156 FERC ¶ 61,234 at P 17; Opinion No. 531, 147 FERC ¶ 61,234 at P 92.

Presiding Judge noted that in Opinion No. 551, the Commission rejected a proposal to use Value Line.¹⁷

10. With regard to the adjusted dividend yield component of the DCF calculation, the Presiding Judge stated that Six Cities and Trial Staff multiplied the unadjusted dividend yield by one plus half the composite growth rate. In contrast, the Presiding Judge noted, PG&E's witness argued that PG&E's short-term growth rate, rather than the composite growth rate, should be used. The Presiding Judge stated that, in populating the DCF formula, $K = (D/P) (1 + 0.5g) + g$, it was "preposterous" for the identical "g" symbols in the formula to have different values, and that PG&E's witness offered no support for the notion that the Commission intended for the formula to be interpreted that way.¹⁸ Moreover, the Presiding Judge observed that in Opinion No. 551, the Commission made clear that the "g" variable represents the composite growth rate. The Presiding Judge thus dismissed PG&E's proposal.¹⁹ Because Six Cities and Trial Staff used the same DCF methodology, but Six Cities' analysis included more recent data, the Presiding Judge adopted Six Cities' DCF calculations for the seven proxy group companies. Thus, the Presiding Judge determined the costs of equity of these companies range from 6.94% to 9.13%, with a median of 7.83%.²⁰

11. Having determined the range of the zone of reasonableness of 6.94% to 9.13%, the Presiding Judge observed that, during times of unusual capital market conditions, the Commission has supported placing transmission owners' base ROE above the central tendency (i.e., the median) of the zone. Accordingly, the Presiding Judge asked: (1) whether the record supports placement of PG&E's ROE above the median of the zone of reasonableness, i.e., 7.83%; (2) if placement of the ROE above the median is warranted, whether the record supports placement of the ROE above the upper median, i.e., 8.54%; and (3) if placement of the ROE above the upper median proves warranted, where, between the upper median and the high end of the zone of reasonableness, i.e., 9.13%, the ROE should be placed.²¹

12. The Presiding Judge observed that during the most recent study period at the time, ending August 31, 2017, market conditions were similar to those in existence during the Opinion No. 551 study period, which the Commission designated as a period of

¹⁷ *Id.* PP 62-64; Opinion No. 551, 156 FERC ¶ 61,234 at P 62.

¹⁸ Initial Decision, 165 FERC ¶ 63,001 at P 66.

¹⁹ *Id.* PP 65-68.

²⁰ *Id.* P 69.

²¹ *Id.* P 172.

anomalous market conditions. After considering yields on one-month and 10-year Treasury Bonds, as well as Federal Reserve holdings, the Presiding Judge found that anomalous market conditions existed during the study period.

13. The Presiding Judge next considered the ROE values provided by PG&E's witness using alternative methodologies that the Commission had previously accepted in Opinion Nos. 531 and/or 551: 9.76% risk premium (Risk Premium), 9.09% Capital Asset Pricing Model (CAPM), 10.31% expected earnings (Expected Earnings). The Presiding Judge stated that since each of these values is substantially higher than the zone of reasonableness' median (7.83%) and upper median (8.54%) produced by the DCF analysis, there was support for an ROE above both benchmarks. Considering state-authorized ROEs, the Presiding Judge found that PG&E's list of vertically integrated utilities is most recent and representative, and notes that the median state-authorized ROE is 9.60%, 47 basis points higher than the upper end of the DCF zone of reasonableness (9.13%).²²

14. According to the Presiding Judge, although *Emera Maine* held that the Commission had not satisfactorily justified its placement of the ROE at the upper midpoint of the zone of reasonableness relevant to the parties in that proceeding, the court stated that the record provided support for placement of the ROE above the midpoint.²³ The Presiding Judge stated that *Emera Maine* arguably stands for the proposition that the Commission may validly use alternative ROE measures to determine whether the ROE should be placed above certain markers, such as the midpoint or median. The Presiding Judge reasoned that, if the record in Opinion No. 531 supported placing the ROE above the midpoint, the record in this proceeding supported placing the ROE not only above the upper median, but also at the high end of the zone of reasonableness.²⁴ The Presiding Judge concluded that since the alternative methodologies and the state-authorized ROEs yield results well above or within four basis points of the upper end of the zone of reasonableness, and since exceeding the zone of reasonableness would be unjust and unreasonable, the only solution was to place PG&E's ROE at the upper end of the zone, i.e., at 9.13%.

2. Briefs on Exceptions

15. PG&E maintains that its requested base ROE of 10.4% is supported by record evidence. PG&E argues, among other things, that the Initial Decision's recommended 9.13% base ROE was unjust and unreasonable because it: (1) conflated the statutory

²² *Id.* PP 173-74.

²³ *Id.* P 171 (referencing *Emera Maine*, 854 F.3d at 28).

²⁴ *Id.* PP 171-177.

zone of reasonableness with the range produced by the two-step DCF; (2) was based on an incomplete consideration of *Emera Maine*; and (3) used a proxy group of companies that did not consider PG&E's higher risks.

16. First, PG&E argues that the Initial Decision erred by assuming that the results of a two-step DCF analysis are equivalent to the range of lawful ROEs that might establish a utility's zone of reasonableness.²⁵ Second, PG&E argues that the Initial Decision perpetuated the error identified in *Emera Maine* because it "did not set forth a rational connection between the record evidence" presented by the various ROE approaches when it concluded that the DCF range was sufficient to establish PG&E's zone of reasonableness.²⁶ Accordingly, PG&E asserts that the Commission should establish a different zone of reasonableness and set PG&E's ROE within that zone. Additionally, PG&E argues that an ROE of 9.13% was not high enough to satisfy the capital attraction standards required by *Hope* and *Bluefield*²⁷ and would undermine the Commission's stated policy goal of attracting investment in infrastructure.²⁸

17. With regard to the proxy group, PG&E maintains that a departure from the Commission's standard screening criteria is warranted based on the specific circumstances of this proceeding. Citing *Emera Maine*, PG&E argues that its witness' recommendation to apply a screen of companies that satisfies *either* the S&P or the Moody's credit rating criteria could account for the facts specific to this proceeding. Regarding growth rates, PG&E contends that the broader list of sources beyond IBES better reflects the range of investors' growth expectations and represents consensus growth estimates that meet the Commission's requirement.²⁹

18. Trial Staff argues that the Initial Decision erred because it: (1) placed PG&E's ROE at the top of the zone of reasonableness without a sufficient connection to the record evidence; (2) determined that anomalous market conditions existed during the study period; and (3) rejected criticisms of certain alternative ROE methodologies.³⁰ Trial Staff states that, if the Commission ultimately decides to apply the framework proposed in Opinion No. 531, it would be necessary to reopen the record in order to allow participants

²⁵ PG&E Brief on Exceptions at 10.

²⁶ *Id.* at 14 (quoting *Emera Maine*, 854 F.3d 9).

²⁷ *Id.* at 11.

²⁸ *Id.* at 17.

²⁹ *Id.* at 20-21.

³⁰ Trial Staff Brief on Exceptions at 3.

to submit evidence and briefs.³¹ Trial Staff states that the D.C. Circuit's determination in *Emera Maine* that the Commission did not establish a rational connection between the record evidence and the Commission's decision to use non-DCF analyses to place the ROE applies here as well. According to Trial Staff, since certain capital market conditions have existed for a decade and since other market conditions have changed, there is no justification for a finding of anomalous market conditions. Finally, Trial Staff argues that the underlying data of the Risk Premium, CAPM, and Expected Earnings models is flawed, and produces distorted results that do not support the Initial Decision's placement of PG&E's ROE at the top of the zone of reasonableness.³² Trial Staff argues that the appropriate ROE placement is the median of the Commission's two-step DCF model.³³

19. Six Cities also argues that the Initial Decision erred in concluding that anomalous capital market conditions justified placing the ROE above the DCF-derived median and in accepting flawed alternative pricing models to establish the ROE. Six Cities asserts that the policies outlined in Opinion No. 531 do not apply.³⁴ Six Cities maintains that the DCF methodology accurately reflects investor expectations and is a reasonable estimate of utilities' cost of equity capital.

20. TANC argues that the Initial Decision erred in: (1) finding that anomalous market conditions existed during the study period; (2) failing to make a finding of fact or conclusion of law that TANC testified to regarding anomalous market conditions; (3) determining that the ROE should be adjusted from the point of central tendency; and (4) placing the recommended ROE at the top of the zone of reasonableness.³⁵ As a general matter, TANC argues that the Commission should apply the ROE policy in place when the record in the TO18 rate period closed, rather than applying the new approach it proposed in Opinion No. 531.³⁶ According to TANC, the Commission's newly proposed policy is incomplete and should not be applied to a proceeding with a complete record.

³¹ *Id.* at 8.

³² *Id.* at 14.

³³ *Id.* at 12.

³⁴ Six Cities Brief on Exceptions at 3-5.

³⁵ TANC Brief on Exceptions at 1-2, 7. SMUD, Modesto, and Santa Clara/M-S-R adopt and incorporate TANC's exceptions with regard to ROE. See SMUD Brief on Exceptions at 1; Modesto Brief on Exceptions at 4; Santa Clara/M-S-R Brief on Exceptions at 4.

³⁶ TANC Brief on Exceptions at 10.

TANC contends that a departure from the Commission's prior policy and a retroactive application of the Commission's new approach would impose burdens on parties that relied on the Commission's older policy when submitting their filings.³⁷

3. **Briefs Opposing Exceptions**

21. PG&E opposes the exceptions of Six Cities, TANC, and Trial Staff. As a general matter, PG&E maintains that the Commission should adopt an overall ROE for PG&E of 10.9%, representing its requested ROE of 10.4% plus the 50 basis point incentive adder for continuing participation in the California Independent System Operator Corporation (CAISO). PG&E reiterates its belief that it is not an "average risk" utility and that the Commission's practice of applying the two-step DCF model and a measure of central tendency to determine ROE should not apply. PG&E argues that adopting the 7.83% ROE as advocated by Six Cities, TANC, and Trial Staff would negatively affect PG&E's ability to attract capital for future investment.³⁸

22. CPUC observes that the rate base of CPUC-jurisdictional projects is more diverse and presents more risks than PG&E's FERC-jurisdictional rate base. CPUC argues that the 9.13% ROE established by the Initial Decision is far more than what is required to attract investment in such activities. Additionally, CPUC agrees with Six Cities' statement that comparing state ROEs to Commission-allowed ROEs is of limited value due to the different ratemaking approaches taken by various regulators.³⁹

23. TANC, Six Cities, and Trial Staff support the Initial Decision's use of the DCF to calculate the zone of reasonableness, and disagree with many of PG&E's exceptions. First, they dispute PG&E's claim that the Commission should modify its screening criteria in selecting PG&E's proxy group.⁴⁰ Second, Six Cities and Trial Staff reiterate the Commission's preference for IBES when selecting growth rate estimates.⁴¹ Third, TANC, Six Cities, and Trial Staff support the Initial Decision's application of Opinion No. 551's guidance to use a composite growth rate for the adjusted dividend yield component of the DCF calculation rather than PG&E's proposed use of the short-term

³⁷ *Id.* at 14.

³⁸ PG&E Brief Opposing Exceptions at 10-11.

³⁹ CPUC Brief Opposing Exceptions at 2-3.

⁴⁰ Six Cities Brief Opposing Exceptions at 8-12; Trial Staff Brief Opposing Exceptions at 11; TANC Brief Opposing Exceptions at 51.

⁴¹ Six Cities Brief Opposing Exceptions at 27; Trial Staff Brief Opposing Exceptions at 12.

growth rate.⁴² In addition, Six Cities argues that PG&E misapplies relevant case law when describing the Commission's section 205 and section 206⁴³ obligations when establishing a reasonable ROE.⁴⁴ TANC and Six Cities also maintain their position that the ROE calculation methodologies that the Commission proposed in recent proceedings such as *Emera Maine* should not apply to this proceeding.⁴⁵ Trial Staff argues that it is unclear whether the Commission's new ROE policy is expected to be applied to this proceeding.⁴⁶

4. Commission Determination

24. In light of developments since the Presiding Judge issued the Initial Decision, we direct additional briefs on the ROE issues in this proceeding. Specifically, on remand from the D.C. Circuit in *Emera Maine*, the Commission proposed a new methodology for determining whether an existing base ROE is unjust and unreasonable under the first prong of section 206 and for determining a new just and reasonable base ROE under the second prong of section 206 when an existing base ROE has been found to be unjust and unreasonable, and the Commission directed briefing on how the methodology should apply to the New England transmission owners' (NETOs) base ROE at issue in *Emera Maine*.⁴⁷ Subsequently, in two proceedings involving the base ROE of Midcontinent Independent System Operator, Inc. (MISO) transmission owners (MISO TOs)⁴⁸ and other cases involving disputed ROEs,⁴⁹ the Commission directed the participants to address, or stated that it expects participants to address, whether and how the Commission's ROE

⁴² TANC Brief Opposing Exceptions at 21; Six Cities Brief Opposing Exceptions at 30; Trial Staff Brief Opposing Exceptions at 13-14.j

⁴³ 16 U.S.C. § 824e (2018).

⁴⁴ Six Cities Brief Opposing Exceptions at 18-19.

⁴⁵ TANC Brief Opposing Exceptions at 40-41; Six Cities Brief Opposing Exceptions at 37.

⁴⁶ Trial Staff Brief Opposing Exceptions at 9.

⁴⁷ See *Coakley v. Bangor Hydro-Elec. Co., et al.*, 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order).

⁴⁸ See *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (MISO Briefing Order).

⁴⁹ See *Ark. Pub. Serv. Comm'n v. Sys. Energy Res.*, 165 FERC ¶ 61,119 (2018).

methodology proposed in the *Coakley* Briefing Order should apply to the facts of specific proceedings.

25. In the *Coakley* Briefing Order and MISO Briefing Order, the Commission proposed to establish a composite zone of reasonableness, giving equal weight to the DCF, CAPM, and Expected Earnings models.⁵⁰ The Commission proposed that, in order to find an existing ROE unjust and unreasonable under the first prong of section 206, that ROE must be outside a range of presumptively just and reasonable ROEs for a utility of its risk profile, absent additional evidence to the contrary. For an average risk single utility, that range would be the quartile of the composite zone of reasonableness centered on the measure of central tendency of the zone of reasonableness. For a below or above average single utility, that range would be the quartile of the zone of reasonableness centered on the measure of central tendency of the lower or upper half of the zone of reasonableness, respectively. The Commission proposed to determine a replacement ROE under the second prong of FPA section 206 using the above three models, plus the Risk Premium model.⁵¹ For an average risk single utility, the Commission proposed to determine the measure of central tendency of each zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models and average those ROEs with the Risk Premium ROE, giving equal weight to each of the four figures. The Commission proposed to use the measure of central tendency of the lower and upper halves of the zones of reasonableness to determine ROEs for single utilities of below and above average risk, respectively.⁵²

26. Finally, the Commission proposed generally to use the same proxy group screening criteria as outlined in Opinion No. 531.⁵³ However, the Commission proposed to apply a high-end outlier test to the results of the CAPM, Expected Earnings and DCF analyses, noting, among other things, that neither the CAPM nor Expected Earnings analyses include a long-term growth projection based on GDP that would normalize the ROEs produced by the model.⁵⁴ The Commission proposed to treat as high-end outliers any proxy company whose cost of equity estimated with a given model is more than 150% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a “natural break” analysis

⁵⁰ See, e.g., *Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 30.

⁵¹ *Id.* P 17.

⁵² *Id.* P 17 & n.62.

⁵³ *Id.* P 49.

⁵⁴ *Id.* P 52.

similar to the approach the Commission uses for low-end DCF analysis results.⁵⁵ In the MISO Briefing Order the Commission explained that, as in the *Coakley* Briefing Order proceeding, the “scope of the paper hearing . . . includes all aspects of [the] proposed methodology.”⁵⁶

27. Additionally, on November 21, 2019, the Commission issued Opinion No. 569 in which it applied a revised methodology for analyzing existing base ROEs under section 206 of the FPA.⁵⁷ The revised methodology applied in Opinion No. 569 used the DCF model and CAPM in the Commission’s analysis, instead of the four models as was proposed in the *Coakley* Briefing Order and MISO Briefing Order.⁵⁸ On May 21, 2020, the Commission issued Opinion No. 569-A to grant rehearing on certain issues.⁵⁹

28. Because the Commission has proposed to change its approach for determining just and reasonable base ROEs, we will reopen the record here for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning the Commission’s revised ROE methodology adopted in Opinion Nos. 569 and 569-A, and whether and how that revised methodology should apply to the facts of this proceeding. Therefore, we establish a paper hearing proceeding to provide the participants, including Trial Staff, the opportunity to submit additional evidence and argument concerning the limited issue of whether and how to apply the revised ROE methodology adopted in Opinion Nos. 569 and 569-A to determine PG&E’s ROE. As

⁵⁵ *Id.* P 53.

⁵⁶ MISO Briefing Order, 165 FERC ¶ 61,118 at P 20 (“In this order, as in the *Coakley* Briefing Order, we do not make any final determinations with respect to the proposed new methodology for analyzing the base ROE component of rates under section 206 of the FPA. The scope of the paper hearing established in this order includes all aspects of this order's proposed methodology.”).

⁵⁷ *Ass’n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019), *order on reh’g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020).[.

⁵⁸ *See, e.g., id.* PP 37, 276.

⁵⁹ Opinion No. 569-A granted rehearing to: (1) allow the use of the Risk Premium model; (2) give the short-term growth rate 80% weighting and the long-term growth rate 20% weighting in the two-step DCF model; (3) modify the high-end outlier test; (4) consider the use of Value Line short-term earnings growth estimates in the CAPM in future proceedings; and (5) calculate the ranges of presumptively just and reasonable base ROEs by dividing the overall composite zone of reasonableness into equal thirds. Opinion No. 569-A, 171 FERC ¶ 61,154.

stated above, initial briefs shall be due 60 days from the date of this order. Responses to those initial briefs shall be due 30 days later. No answers or additional briefs will be permitted.

B. Cost of Long-Term Debt

29. PG&E forecasted the cost of debt that it would incur for debt issuances that it expected to make during Period II (2017) by starting with recorded, end-of-year data from Period I (2015) and then estimating the long-term debt costs that it would incur during the remainder of 2016 and calendar year 2017. Specifically, PG&E started with its utility cost of debt of 5.09% as of May 31, 2016, and used (1) a forecast of future interest rates from IHS Global Insight for 2016 and 2017 to estimate changes to the interest rates on variable rate debt; and (2) a forecast of the three-month commercial paper rate for future interest rates on tax-exempt Pollution Control bonds, resulting in an average cost of debt forecast for 2017 of 5.13%.⁶⁰

1. Reasonableness of Forecasted Cost of Debt

a. Initial Decision

30. The Presiding Judge observed that PG&E forecast four new issuances of long-term debt for 2017, and that all were made at significantly lower cost than forecasted.⁶¹ The Presiding Judge thus found that there had been known and measurable changes to PG&E's long-term debt cost that would reduce its Period II cost of long-term debt. Therefore, the Presiding Judge found that PG&E's cost of debt, as forecasted, was unjust and unreasonable, and should be reduced.⁶²

31. In making this finding, the Presiding Judge explained that, in general, the Commission's preference is to rely on test year data, if it was "reasonable when made"⁶³ and that the Commission will rely on such data "unless it can be demonstrated that the estimates were either unreasonable when made or, if reasonable when made, subsequent events indicate that to use them as a basis for future projections would yield unreasonable

⁶⁰ Ex. PGE-0013 at 2:15-3.7.

⁶¹ Initial Decision, 165 FERC ¶ 63,001 at P 180 (citing PG&E Filing, Ex. PGE-0021 (Period II Statements) at 73, Ex. CIT-0015 at 2, and Ex. CIT-0063 (PG&E Data Response) at 1).

⁶² *Id.* P 181.

⁶³ *Id.* P 182 (citing *Sw. Pub. Serv. Co. v. FERC*, 952 F.2d 555, 557 (D.C. Cir. 1992) (*Southwestern Public Service*)).

results.”⁶⁴ The Presiding Judge stated that with respect to such subsequent events, the Commission has allowed the use of an adjustment to actual data to reflect “changes in the rate of return regardless of scale”⁶⁵ and that the Commission has described the rationale for this policy as follows:

Capitalization costs differ from other costs Interest rates and other security yields have tended to rise and fall rather sporadically and often unexpectedly over time without equally visible and convincing evidence of offsetting cost trends. We shall therefore continue to resist piecemeal, post-test year changes in other cost factors, but we will accord to financing costs the different and separate treatment that we think they deserve.⁶⁶

32. The Presiding Judge stated that the D.C. Circuit recognized the distinction between data related to capital structure and rate of return, explaining that “[t]he Commission does draw a distinction between changes in rate of return and all other changes, allowing a spot adjustment for the former even where the change is *slight*.”⁶⁷ The Presiding Judge stated that cost of debt is a component of a utility’s rate of return and that the record shows that there have been known and measurable changes in PG&E’s long-term debt cost rate. The Presiding Judge stated that even if it is assumed that PG&E’s estimates were reasonable when made, subsequent events – the actual debt issuances – “indicate that to use [the estimates] as a basis for future projections would yield unreasonable results.”⁶⁸ The Presiding Judge found that for PG&E’s proposed cost of debt to be just and reasonable, PG&E must recalculate that cost, using its actual long-term debt issuances and properly calculated coupon rates for 2017.⁶⁹

⁶⁴ *Id.* (citing *S. Cal. Edison Co.*, Opinion No. 55, 8 FERC ¶ 61,099, at 61,375 (*SoCal Edison*), *reh’g denied*, 9 FERC ¶ 61,006 (1979); *Southwestern Public Service*, 952 F.2d at 556 (“Where challengers of the proposed rate show that use of the estimates would be ‘unreasonable’ . . . even though the estimates were reasonable when made, the Commission will order a ‘spot adjustment’ in the light of more current data.”)).

⁶⁵ *Id.* (citing *Southwestern Public Service*, 952 F.2d at 558).

⁶⁶ *Id.* P 183 (citing *Union Elec. Co.*, 47 FPC 144, 155-56 (1972)).

⁶⁷ *Id.* P 184 (citing *Southwestern Public Service*, 952 F.2d at 558 (emphasis in original)).

⁶⁸ *Id.* P 185 (citing *SoCal Edison*, 8 FERC at 61,375).

⁶⁹ *Id.* P 186.

b. Briefs on Exceptions

33. PG&E contends that the Initial Decision threw out PG&E's forecast without identifying any issues with its forecast methodology, and seemed to conclude that any divergence between the forecast and after-the-fact actual data would yield "unreasonable results."⁷⁰ PG&E argues that this approach is fundamentally inconsistent with the Commission's "reasonable when made" standard and is unsupported by *SoCal Edison*, on which the Initial Decision relied. PG&E notes that the Commission explained in *SoCal Edison* that "[t]he challenging party must demonstrate that the particular expense was...*substantially* in error because of subsequent events which were not reasonably foreseeable at the time such estimates were developed."⁷¹ PG&E also notes that in *SoCal Edison*, the Commission concluded that the estimate should be adhered to in that case, notwithstanding the fact that actual costs were different than the forecast in several respects.⁷² PG&E argues that the Presiding Judge made no finding in the Initial Decision that its forecast was "*substantially* in error" and contends that adopting the approach in the Initial Decision would reject the Commission's long-standing preference to rely on test year data and, as a result, no forecast would ever be accepted unless it happened to match exactly the actual experience after the forecast was made and right up until the hearing.⁷³ PG&E contends that its forecast was reasonable when made and relied on independent, third party data sources, and that its forecast should be used in establishing the cost of debt for the forecast period.⁷⁴

c. Briefs Opposing Exceptions

34. TANC, Trial Staff, Six Cities, and SWP contend that the Initial Decision correctly found that PG&E's cost of long-term debt as forecasted is unjust and unreasonable, given known and measureable changes that would reduce PG&E's Period II cost of long-term debt, and that PG&E's proposed cost of debt must be reduced.⁷⁵ TANC disagrees with

⁷⁰ PG&E Brief on Exceptions at 27-28.

⁷¹ *Id.* at 28 (citing *SoCal Edison*, 8 FERC at 61,375 (citation omitted, emphasis in original)).

⁷² *Id.* at 29.

⁷³ *Id.*

⁷⁴ *Id.*

⁷⁵ TANC Brief Opposing Exceptions at 43-45; Trial Staff Brief Opposing Exceptions at 16-17; Six Cities Brief Opposing Exceptions at 41-44; CDWR Brief Opposing Exceptions 3-5.

PG&E that the Initial Decision had to first find that PG&E's forecast was "substantially in error" before finding the forecast would yield unreasonable results, asserting that Commission precedent requires no such finding.⁷⁶ TANC contends that, unlike in *SoCal Edison*, PG&E's debt estimates are not based on recent trends and cannot be relied upon.⁷⁷ Six Cities argues that given the Commission's policy allowing for the use of post-filing data for rate of return and the unreasonable rates resulting from the use of PG&E's forecasted cost of debt, the Initial Decision properly determined that PG&E's cost of long-term debt should be updated to reflect actual data.⁷⁸

d. Commission Determination

35. We affirm the Presiding Judge's determination that PG&E's cost of debt, as forecasted, is unjust and unreasonable and must be reduced. PG&E argues that that the Initial Decision had to first find that PG&E's forecast was "substantially in error" before finding the forecast would yield unreasonable results. We disagree. In *Southwestern Public Service*, the D.C. Circuit explained that in *SoCal Edison*, the Commission restated its policy permitting spot adjustments to reflect changes in *any* area of costs or revenues, so long as the changes were unforeseeable and "*substantially in error*" and would yield unreasonable rates.⁷⁹ However, *Southwestern Public Service* went on to state that "[t]he Commission does draw a distinction between changes in rate of return and all other changes, allowing a spot adjustment for the former even where the change is *slight*."⁸⁰ As the Initial Decision notes, *Southwestern Public Service* emphasized the different treatment of rate of return cost in quoting an earlier Commission decision: "We . . . continue to resist piecemeal, post-test year changes in other cost factors, but we will accord to financing costs the different and separate treatment that we think they deserve."⁸¹ *Southwestern Public Service* concluded that Commission precedent reflects two independent exceptions to the general policy against spot adjustments of estimates that were reasonable when made. Specifically, the court found that spot adjustments may be used to reflect (1) changes in the rate of return regardless of scale; and (2) substantial deviations between estimates and later data that would result in unreasonable rates. As

⁷⁶ TANC Brief Opposing Exceptions at 44.

⁷⁷ *Id.* at 45.

⁷⁸ Six Cities Brief Opposing Exceptions at 44.

⁷⁹ *Southwestern Public Service*, 952 F.2d at 557-558 (emphasis in original).

⁸⁰ *Id.* at 558 (emphasis in original).

⁸¹ *Id.* (citing *Pub. Serv. Co. of New Mexico*, 10 FERC ¶ 61,053 (1980) (quoting *Union Elec. Co.*, 47 FPC 144)).

the D.C. Circuit explained in *Southwestern Public Service*, the two exceptions do not conflict; rather, they exist side by side.⁸²

36. Cost of debt is a component of a utility's rate of return. PG&E argues that the Initial Decision had to first find that PG&E's forecast was "substantially in error" before finding the forecast would yield unreasonable results.⁸³ However, as discussed above, rate of return is afforded different treatment than other cost components.⁸⁴ Accordingly, we disagree with PG&E's arguments concerning the "substantially in error" requirement and conclude that it does not apply to PG&E's forecast of long-term debt. Instead, as discussed above, the Commission will allow the use of an adjustment to actual data to reflect changes in the rate of return regardless of scale, even if estimates were reasonable when made and the change is slight. Here, the record shows that there have been known and measurable changes in PG&E's long-term debt cost rate, as discussed below.

37. In the Initial Decision, the Presiding Judge included a table that depicted PG&E's forecasted and actual amounts associated with four new issuances of long-term debt for 2017 (Period II). The table demonstrates issuances were made at significantly lower costs than forecasted:

Table 1	Debt Amount		Coupon Rate	
	Forecasted	Actual	Forecasted	Actual
New Issuance Q1 2017 (10-year)	\$245 million	\$400 million	4.54%	3.30%
New Issuance Q1 2017 (30-year)	\$455 million	\$200 million	5.54%	4.00%
New Issuance Q4 2017 (10-year)	\$289 million	\$1,150 million	4.54%	3.30%
New Issuance Q4 2017 (30-year)	\$536 million	\$850 million	5.54%	3.95%

⁸² *Southwestern Public Service*, 952 F.2d at 558.

⁸³ PG&E Brief on Exceptions at 28.

⁸⁴ *See supra* PP 47-48.

38. These differences show that there were known and measurable changes in PG&E's long-term debt cost rate. As discussed above, Commission precedent allows spot adjustments to be used for long-term debt forecasts, even if the estimates were reasonable when made, to reflect: (1) changes in the rate of return regardless of scale; and (2) substantial deviations between estimates and later data that would result in unreasonable rates.⁸⁵ We find that the Presiding Judge correctly applied the Commission's precedent here, and affirm this finding. Accordingly, we direct PG&E to recalculate its cost of long-term debt using its actual costs for 2017 in a compliance filing to be submitted within 60 days after the Commission order on the paper hearing we established above concerning the application of the Commission's proposed revised ROE methodology discussed above.

2. Use of Net Proceeds to Calculate Long-Term Debt Costs

39. PG&E proposed to calculate its cost of debt by dividing the annual payments that it must make on each debt issuance by the net proceeds of the issuance, which is the face value of the debt minus the issuance costs and any cash discount.⁸⁶

a. Initial Decision

40. The Presiding Judge concluded that the Commission's decision in *System Energy Resources, Inc.* dictated using the gross proceeds of the debt issuance to calculate PG&E's cost of debt, rather than net proceeds.⁸⁷ The Presiding Judge explained that in *SERI*, the company proposed to use the net proceeds method to calculate the cost-of-debt component of its capital structure, arguing that use of the gross proceeds method caused the company to under-recover its cost. The Commission rejected this argument and held that the cost-of-debt component should reflect the "company's total obligation [to its creditors] with respect to long-term debt."⁸⁸ Moreover, in denying rehearing in the *SERI* proceeding, the Commission concluded that the gross proceeds methodology "allows for a more accurate picture of [a company's] capital structure and, in turn, results in the correct calculation of [a company's] cost of capital."⁸⁹ Because PG&E made no attempt

⁸⁵ *Id.*

⁸⁶ See Ex. PGE-0046 (Rebuttal Testimony of Marques A. Cruz) at 11:12-12:3.

⁸⁷ Initial Decision, 165 FERC ¶ 63,001 at P 189 (citing *Sys. Energy Res., Inc.*, Opinion No. 446, 92 FERC ¶ 61,119 (2000) (*SERI*), *order on reh'g*, Opinion No. 446-A, 96 FERC ¶ 61,165 (2001)).

⁸⁸ *Id.* (citing *SERI*, 92 FERC at 61,449).

⁸⁹ *Id.* P 190 (citing Opinion No. 446-A, 96 FERC at 61,740; *Portland Nat. Gas Transmission Sys.*, Opinion No. 524, 142 FERC ¶ 61,197, at PP 263-265 (2013) (finding

to distinguish *SERI* in either of its post-hearing briefs, the Presiding Judge directed PG&E to use the gross proceeds method to recalculate its cost of debt.⁹⁰

b. Briefs on Exceptions

41. PG&E contends that although it did not distinguish *SERI*, it did explain that the applicable Commission regulation permits a utility to use net proceeds. PG&E states that clause B(6) of section 35.13 (h)(22)(ii) of the Commission's regulations provides that the cost of money to be used in the calculation of the weighted cost of long-term debt "is the yield to maturity at issuance based on the interest rate and *net proceeds* to the utility determined by reference to any generally accepted table of bond yields."⁹¹ PG&E notes that its witness demonstrated that the use of net proceeds is the only methodology that allows a utility to recover the full costs of its debt financing, and that no party presented testimony or examples to rebut this fact.⁹² PG&E argues that on that basis, the Commission should approve PG&E's use of net proceeds in this proceeding.⁹³

42. Trial Staff contends that the Initial Decision erred in finding that *SERI* dictates using the gross proceeds method, and that PG&E's proposal to use net proceeds to calculate its long-term debt costs is appropriate.⁹⁴ Trial Staff explains that the issue is whether PG&E's proposal to use net proceeds to calculate its long-term debt cost rate is appropriate, not whether the use of such method is appropriate to calculate the debt component of its proposed capital structure. Trial Staff asserts that *SERI* addresses the use of gross proceeds for long-term debt principal outstanding, to calculate the debt

that the *SERI* holding is not limited to electric utilities and that a natural gas pipeline must use the gross proceeds method); *El Paso Nat. Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at PP 583-585 (2013) (affirming the Presiding Judge's finding that the gross proceeds method must be used to compute the debt ratio for pipeline's capital structure)).

⁹⁰ *Id.* P 191.

⁹¹ PG&E Brief on Exceptions at 30 (citing 18 C.F.R. § 35.13(h)(22)(ii)(B)(6) (2020) (emphasis added)).

⁹² *Id.* at 30-31 (citing Ex. PGE-0046 at 13:9 – 19:14).

⁹³ *Id.* at 31. PG&E adds that, in the event that the Commission interprets *SERI* to be an obstacle to that result, it should reconsider its analysis in *SERI* and allow for the use of the net proceeds method, arguing that the *SERI* decision is simply incorrect. *Id.*

⁹⁴ Trial Staff Brief on Exceptions at 27.

component of the capital structure.⁹⁵ Trial Staff states that in *SERI*, the Commission approved a proposed switch to the embedded cost method for determining the long-term debt cost rate, but rejected the proposed switch to a net proceeds method for deriving the long-term debt ratio. Trial Staff argues that the gross proceeds methodology is appropriate to use to calculate the debt ratio but is not appropriate to calculate PG&E's long-term debt costs.⁹⁶ Trial Staff also notes that *SERI* indicates that the embedded cost of debt calculation considers discounts, which is clearly not the use of the gross proceeds method.⁹⁷

c. Briefs Opposing Exceptions

43. TANC opposes PG&E's and Trial Staff's argument that PG&E can use net proceeds to calculate its cost of debt, contending that Commission regulations require PG&E to use gross proceeds to compute its long-term debt costs.⁹⁸ TANC cites the Commission's explanation in *SERI* that the capital structure should reflect gross proceeds for debt because this method reflects the company's total obligation with respect to long-term debt.⁹⁹ TANC thus argues that the Commission should affirm the Initial Decision's directive that PG&E use the gross proceeds method to recalculate its cost of debt.¹⁰⁰

d. Commission Determination

44. The Presiding Judge explained that in *SERI*, the Commission rejected the company's proposal to use the net proceeds method to calculate the cost of debt component of its capital structure. However, as pointed out by Trial Staff, that decision addressed the use of gross proceeds for long-term debt principal outstanding to calculate the long-term debt ratio, not the long-term debt costs. Accordingly, we find *SERI* is distinguishable from the facts before us here. The Commission has previously stated that cost of debt should be on a net proceeds basis so that the utility can fully recover the

⁹⁵ *Id.* at 27-28.

⁹⁶ *Id.* at 28.

⁹⁷ *Id.* at 29 (citing *SERI*, 92 FERC at 61,447-48 & n.37).

⁹⁸ TANC Brief on Exceptions at 45-46.

⁹⁹ *Id.* at 47 (citing *SERI*, 92 FERC at 61,740).

¹⁰⁰ *Id.*

underwriter's compensation and the expenses of financing.¹⁰¹ Furthermore, section 35.13(h)(22)(ii)(a) of the Commission's regulations states:

The weighted cost [of long-term debt] is calculated by: (1) Multiplying the cost of money for each issue under clause (B)(6) below by the principal amount outstanding for each issue...

In turn, clause (B)(6) states that the "cost of money" is:

the yield to maturity at issuance based on the interest rate and net proceeds to the utility determined by reference to any generally accepted table of bond yields.

45. Accordingly, we agree with PG&E and Trial Staff and find that the use of net proceeds to calculate the long-term debt cost rate is appropriate. We therefore reverse the Initial Decision on this issue and conclude that PG&E's approach is just and reasonable.

3. Remaining Issues

46. In its filing, PG&E forecast a split 10-year and 30-year bond issuances as 35% and 65%, respectively.¹⁰² PG&E used a forecast of future interest rates from IHS Global Insight Inc. for 2016 and 2017 to estimate changes to the interest rates on PG&E's variable rate debt and a forecast of the three-month commercial paper rate for future interest rates on tax-exempt Pollution Control bonds.¹⁰³

a. Initial Decision

47. The Presiding Judge stated that PG&E's forecasted split of 10-year and 30-year bond issuances and forecasted interest rate estimates are part of a larger matter, i.e., whether PG&E used the correct methodology in forecasting its long-term debt. The Presiding Judge found that because the preceding analysis substitutes PG&E's actual cost of debt during 2017 with its forecasted cost of debt for that year, further questions regarding the validity of PG&E's forecast methodology are moot.¹⁰⁴

¹⁰¹ See, e.g., *Mich. Gas Storage Co.*, 87 FERC ¶ 61,038 at 61,165-66 (1999).

¹⁰² PG&E Initial Brief at 20.

¹⁰³ *Id.* at 17.

¹⁰⁴ Initial Decision, 165 FERC ¶ 63,001 at P 192.

b. Briefs on Exceptions

48. PG&E notes that since the Presiding Judge made no determination with respect to the above noted issues, instead finding them moot, there was nothing specifically to which PG&E can take exception with respect to its forecasted split of 10-year and 30-year bond issuances and its interest rate estimates.¹⁰⁵ That said, PG&E reiterates that events affecting it, including the fact that it was, at the time of the hearing, on a credit watch for possible downgrade, underscore why after-the-fact second-guessing of “reasonable when made” forecasts is not, and should not be, the Commission’s approach.¹⁰⁶

49. TANC concurs with the Initial Decision’s determination to use actual 2017 long-term debt costs, and agrees that such ruling obviates the need to decide these issues.¹⁰⁷ However, TANC states that if the Commission overturns the Initial Decision and determines PG&E’s debt on a forecast basis, TANC argues that PG&E’s forecasts for its split of 10-year and 30-year bond issuances and its interest rate estimates are unjust and unreasonable.¹⁰⁸

c. Briefs Opposing Exceptions

50. PG&E continues to argue that its forecasts for its split of 10-year and 30-year bond issuances and interest rate estimates are just and reasonable,¹⁰⁹ and TANC and SWP raise objections to various aspects of PG&E’s forecast methodology.¹¹⁰

d. Commission Determination

51. We affirm the Presiding Judge’s finding that, since we are directing PG&E to use its actual cost of debt during 2017 with its forecasted cost of debt for that year,¹¹¹ further questions regarding the validity of PG&E’s forecast methodology are moot. We note that

¹⁰⁵ PG&E Brief on Exceptions at 31.

¹⁰⁶ *Id.* at 32-33.

¹⁰⁷ TANC Brief on Exceptions at 41.

¹⁰⁸ *Id.* at 42-46.

¹⁰⁹ PG&E Brief Opposing Exceptions at 34-35.

¹¹⁰ TANC Brief Opposing Exceptions at 49-52; SWP Brief Opposing Exceptions at 4-5.

¹¹¹ *See supra* P 48.

PG&E stated that since the Presiding Judge found these issues moot, there was nothing specifically to which PG&E can take exception with respect to its forecasted split of 10-year and 30-year bond issuances and its interest rate estimates. We also note that TANC concurs with the Initial Decision's determination to use actual 2017 long-term debt costs, and that such ruling obviates the need to decide these issues. Therefore, we do not address PG&E's and TANC's arguments on PG&E's forecasted split of 10-year and 30-year bond issuances and its interest rate estimates.

C. Capital Structure

52. PG&E proposed a target capital structure of 47.00% long-term debt, 1.00% preferred equity and 52.00% common equity for 2017. According to PG&E, the same target capital structure was established by CPUC in Decision 12-12-034 on December 20, 2012.¹¹²

1. Initial Decision

53. The Presiding Judge stated that the Commission prefers to use the applicant's proposed capital structure if it satisfies a three-prong test, where the applicant "(1) issues debt that is not guaranteed by another entity, (2) has a bond rating, and (3) has an equity ratio that (a) is within the historical range approved by the Commission, and (b) is not excessive in comparison with the equity ratio of the proxy-group companies."¹¹³ The Presiding Judge found that PG&E satisfied this test because it issues its own bonds and has its own bond rating, and PG&E's capital structure is within the range allowed for utilities by the Commission.¹¹⁴ The Presiding Judge noted that historically, the Commission has allowed a maximum equity ratio of 68.86% (minimum debt ratio of 31.14%) and a maximum debt ratio of 64.76% (minimum equity ratio of 35.24%).¹¹⁵

54. The Presiding Judge also analyzed Trial Staff's forecast, which asserted that PG&E's capital structure at the end of Period II (December 31, 2017) should be 52.00%

¹¹² PG&E Filing, Ex. PGE-0021 (Period II Statements) at 70; Ex. S-0009 (Workpapers in Support of Trial Staff Testimony) at 463.

¹¹³ Initial Decision, 165 FERC ¶ 63,001 at P 194 (citing *Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, at 61,667 (1997), *order on reh'g*, 84 FERC ¶ 61,084, at 61,415 (1998); *Enbridge Pipeline s (Southern Lights) LLC*, 139 FERC ¶ 63,015 (2012); *ITC Holdings Corp.*, 121 FERC ¶ 61,229, at P 49 (2007)).

¹¹⁴ *Id.* P 195 (citing Ex. S-0006 (Testimony of Douglas Green) at 72:20-73:1-6).

¹¹⁵ *Id.* (citing *Pac. Gas Transmission Co.*, 62 FERC ¶ 61,109, at 61,778-79 (1993); *Allegheny Power*, 106 FERC ¶ 61,241, at PP 25-27 (2004)).

common equity, 0.68% preferred equity, and 47.32% long-term debt.¹¹⁶ The Presiding Judge found that implementing PG&E's forecasted capital structure rather than that the capital structure forecasted by Trial Staff will increase the company's cost of service. Because Trial Staff's forecasted capital structure allocates a lower share to PG&E's preferred stock than does PG&E's forecast, the cost of PG&E's preferred stock, 5.52%, will be higher than the cost of PG&E's debt.¹¹⁷ The Presiding Judge thus concluded that for PG&E's rate of return to be just and reasonable the utility must implement Trial Staff's proposed capital structure rather than PG&E's forecasted capital structure to avoid the increase of cost of service.¹¹⁸ The Presiding Judge was not persuaded by PG&E's contention that it would have to maintain two separate capital structures, one for the Commission and one for CPUC, while the deviation of only 0.32%, between the two forecasted capital structures is too small to justify requiring it to carry this burden. The Presiding Judge concluded that "ratepayers deserve to pay no more than their cost of service" and "that consideration outweighs any concern one might have for PG&E's administrative burdens."¹¹⁹

2. Briefs on Exceptions

55. PG&E contends that the Initial Decision departs from the Commission's "three-prong test" for using actual capital structure, and instead relies on Trial Staff's forecast.¹²⁰ PG&E claims that the parties did not make a compelling argument for why it is necessary or appropriate for PG&E to change its capital structure.¹²¹ PG&E argues that the difference between its as-filed forecast and Trial Staff's forecast adopted in the Initial Decision is very small – a shift of 0.32% from preferred equity to long-term debt. In PG&E's opinion, that small difference is not sufficient to demonstrate that its proposed capital structure forecast was not reasonable when made and does not demonstrate that PG&E's estimate was "*substantially* in error," as required by Commission precedent.¹²² PG&E adds that the Commission should not order it to maintain two ever-so-slightly

¹¹⁶ *Id.* P 196 (citing Ex. S-0006 at 71:9-13).

¹¹⁷ *Id.* P 202.

¹¹⁸ *Id.* PP 201-202.

¹¹⁹ *Id.* P 203.

¹²⁰ PG&E Brief on Exceptions at 33 (citing Initial Decision, 165 FERC ¶ 63,001 at PP 194, 196–199).

¹²¹ *Id.* at 34.

¹²² *Id.* at 33-34.

different capital structures – one for its Commission-jurisdictional electric transmission business and a different one for its CPUC-jurisdictional businesses.¹²³

3. Briefs Opposing Exceptions

56. TANC contends that the Commission should deny PG&E’s exception on this issue because its contention that the parties did not make a compelling argument for a different capital structure is irreconcilable with Trial Staff’s testimony and therefore is baseless.¹²⁴

57. Trial Staff states that the Initial Decision properly found that PG&E must implement its proposed capital structure.¹²⁵ Trial Staff argues that PG&E does not dispute its forecast and that it recognizes that CPUC’s capital structure does not bind the Commission.¹²⁶ Further, Trial Staff cites the Initial Decision’s conclusion that “[r]atepayers deserve to pay no more than their cost of service,” and that that consideration outweighs any of PG&E’s concerns about administrative burden.¹²⁷

4. Commission Determination

58. We affirm the Presiding Judge’s finding that PG&E should adopt the capital structure proposed by Trial Staff’s witness. In developing his proposal, Trial Staff’s witness largely adopted PG&E’s target capital structure, which was established by the CPUC in 2012, but made adjustments to it based on more recent data. For example, Trial Staff’s long-term debt forecast was based on PG&E’s actual and forecasted debt issuances through December 31, 2017, using more recent FERC Form No. 1 data, that was obtained through discovery requests in this proceeding, and PG&E’s forecasted debt issuances through the end of 2017.¹²⁸ Because Trial Staff’s proposed capital structure is updated and more precise than PG&E’s, we find, on balance, that Trial Staff’s proposal is more persuasive than PG&E’s proposal.

59. Meanwhile, PG&E’s argument against adopting Trial Staff’s calculation focuses on the administrative burden of having to maintain two slightly different capital structures for its Commission-jurisdictional electric transmission business and its CPUC-

¹²³ *Id.* at 33-34.

¹²⁴ TANC Brief Opposing Exceptions at 53 (citing Ex. S-0006 at 71-76).

¹²⁵ Trial Staff Brief Opposing Exceptions at 17.

¹²⁶ *Id.* at 18.

¹²⁷ *Id.* at 18–19 (citing Initial Decision, 165 FERC ¶ 63,001 at P 203).

¹²⁸ See Ex. S-0006 at 71-76; Trial Staff Initial Brief at 61-63.

jurisdictional businesses.¹²⁹ However, we conclude that the fact that PG&E believes maintaining two capital structures would be administratively burdensome is not persuasive, given that the CPUC-approved capital structure PG&E proposes to use is from 2012, and Trial Staff's adjustments reflect more recent data, as discussed above.¹³⁰ We therefore adopt the capital structure calculated by Trial Staff and direct PG&E to adjust its rate base accordingly on compliance.

D. Depreciation Rates

60. PG&E developed rates of depreciation for ten of its transmission plant accounts using the traditional, straight-line methodology.¹³¹ First, PG&E ascertained the original costs of plant in the account and added the net salvage amounts.¹³² Second, PG&E subtracted from that sum the amount of depreciation that has already been expensed, yielding the future or remaining accruals, which is the dollar amount of the plant remaining in the account to be depreciated. Third, PG&E determined the average remaining life of the facilities (the average life, in years, of how long facilities already in service are expected to last) by selecting the appropriate "survivor curves." The remaining accruals (undepreciated amounts) for each account were divided by the average remaining life to determine the account's average annual accrual (i.e., depreciation expense). That amount was then divided by the original cost of the facilities

¹²⁹ See Initial Decision, 165 FERC ¶ 63,001 at P 201. PG&E also argues that under Commission precedent its estimate can be rejected only if it is found to be substantially in error. See PG&E Brief on Exceptions at 33-34. . However, PG&E does not explain how the "substantially in error" standard applies to determining a utility's capital structure.

¹³⁰ We also note that the Commission is not bound by state commission decisions when examining wholesale rates. See, e.g., *Piedmont Mun. Power Agency v. Duke Energy Carolinas, LLC*, 162 FERC ¶ 61,109, at P 32 (2018).

¹³¹ PG&E Filing, Ex. PGE-0010A (Testimony of Ned. W. Allis) at 9, Table PGE-0010A-2.

¹³² Net salvage is a part of depreciation and either subtracts from or adds to what a company may collect through depreciation, depending on whether, on a net basis, a company received funds upon the retirement of an item, or incurred costs to retire an item. PG&E proposes net salvage amounts that add to depreciation in all of its accounts, ranging in amounts from 20% to 110% of the original costs.

to determine the depreciation rates. Using this methodology, PG&E proposed a composite depreciation rate of 3.26%.¹³³

61. TANC and Trial Staff followed the same methodology in calculating their proposed depreciation rates. TANC recommended reducing that rate to 1.94%, which would lower PG&E's proposed Transmission Revenue Requirement (TRR) by \$119 million.¹³⁴ Trial Staff proposed a composite rate of 2.08%, which would lower PG&E's proposed TRR by \$107 million.¹³⁵ Two of the components that factor into the calculation of the depreciation rates were disputed by the parties and are discussed below – the average remaining lives and net salvage amounts.

1. Average Remaining Service Lives and Dispersion Patterns (i.e., Iowa Curves)

62. The term “survivor curve,” as used by the participants in this proceeding, describes two patterns that are depicted on graphs. One is a pattern of small triangles or squares that depict an account's historic retirement dispersions—the percentage of facilities retired at different ages. These are referred to as “observed survivor curves.” The other is a smooth curve that purports to depict the account's future dispersion patterns. The participants have selected these curves from a family of 31 standardized survivor curves called “Iowa Curves”¹³⁶ that provide standardized patterns of retirement dispersion.¹³⁷ Average remaining life is determined by calculations involving the portion of the graph below the curve.¹³⁸

a. Initial Decision

63. The Presiding Judge explained that three categories of Iowa Curves, designated by the letters L, S and R,¹³⁹ are relevant to this proceeding, and that each letter represents a

¹³³ Ex. PGE-0010A at 6:7-10, 8, Table PGE-0010A-1.

¹³⁴ TANC, Ex. TNC-0005 (Testimony of James Garren) at 8, Table TNC-0005-1.

¹³⁵ Trial Staff, Ex. S-0001 (Testimony of Kevin J. Pewterbaugh) at 4:11-14, 7:14-15.

¹³⁶ So called because they were developed at Iowa State University.

¹³⁷ Ex. TNC-0005 at 11-12.

¹³⁸ For a more detailed description of how Iowa Curves work, see Initial Decision, 165 FERC ¶ 63,001 at PP 214-224.

¹³⁹ These letters describe the location of the mode relative to the average service

different dispersion pattern and also have numerical suffixes that differentiate the dispersion patterns further, *e.g.*, “R1,” “S2,” *etc.*¹⁴⁰ The Presiding Judge stated that the curves also have numerical prefixes that designate the average service life of the facilities (the number of years that a new unit of plant is expected to last).¹⁴¹

64. The Presiding Judge stated that before selecting an Iowa Curve, one must organize the historical data that shows past dispersion patterns; one means of doing so is to create an “original life table”¹⁴² and then use computer programs to mathematically determine which Iowa Curves most closely match the data in the original life tables.¹⁴³ The Presiding Judge stated that the programs use a “least squared differences” approach to determine the best mathematical fit, in which they square the difference between each data point contained in the original life table and the corresponding data point graphically represented in the Iowa Curve. The Iowa Curve with the least difference from the original life table is deemed the best mathematical fit.¹⁴⁴ The Presiding Judge stated that there are two methods of developing data with which to populate original life tables; (1)

life of the facility. An “S” (symmetrical) curve would be used if the mode coincides with the average service life; an “L” curve if the mode was at a younger age than (to the left of) the average service life; and an “R” curve if the mode falls after (to the right of) the average service life.

¹⁴⁰ Initial Decision, 165 FERC ¶ 63,001 at P 217 (citing Ex. PGE-0010A at 16:27-17:6, 18-22).

¹⁴¹ *Id.* (citing Ex. TNC-0005 at 4:15-16). For example, an Iowa Curve designated 48-S1 is designed to fit facilities with an S1 dispersion pattern and an average service life of 48 years.

¹⁴² An original life table contains six columns showing: (1) the age of the plant component, starting with 0.0 years, moving to 0.5 years, then proceeding at one-year intervals and ending with the oldest component; (2) the remaining accruals (the dollar amount that remains exposed to depreciation) at the beginning of each age interval; (3) the dollar amounts of the plant retirements during the age interval; (4) the retirement ratio (the ratio of the dollar amount of retirements during the interval to the dollar amount of the remaining accruals at the beginning of the interval); (5) the survival ratio (the ratio of the dollar amount of remaining accruals at the end of the interval to the dollar amount of the remaining accruals at the beginning of the interval); and (6) the percentage of surviving plant at the beginning of each interval. For an example, see PG&E’s original life tables for its Account No. 352.01, contained on pages 4-9 of Exhibit PGE-0029.

¹⁴³ Initial Decision, 165 FERC ¶ 63,001 at PP 218-220.

¹⁴⁴ *Id.* PP 220-224.

the “actuarial” method, which is based on actual historical data, and (2) the STAGE method, which involves statistical aging of PG&E’s facilities to calculate their likely vintages.¹⁴⁵ The Presiding Judge explained that another means of organizing unaged historical data is the Simulated Plant Record, which does not involve creation of original life tables.¹⁴⁶ The Presiding Judge stated that this method is used if the retirement dates or annual plant balances are known, but the vintages of the facilities are either not available or the paucity of data regarding such vintages precludes reliance upon them.¹⁴⁷ The Presiding Judge found that the actuarial method appeared to be the most reliable way of the three methods of organizing the data used to mathematically or visually compare the various curves.¹⁴⁸

65. The Presiding Judge noted that the participants actively dispute nine of the ten accounts, agreeing that the Iowa Curve selected for Account 352.02 should be the same as that selected for Account 352.01, because the former account lacks sufficient data upon which to otherwise select an appropriate curve.¹⁴⁹ The Presiding Judge stated that although PG&E, TANC, and Trial Staff all performed mathematical computations ranking Iowa Curves on a least squared basis, PG&E provided no mathematical analysis to support its Iowa Curve recommendations¹⁵⁰ and TANC’s analyses were suspect because they used the less accurate STAGE method and contained mathematical errors.¹⁵¹ The Presiding Judge found that the analyses Trial Staff prepared using PG&E’s actuarial tables are based on the soundest underlying data, and gave weight to the proposed Iowa Curves that most closely resemble the Iowa Curves ranked in Trial Staff’s mathematical analyses.¹⁵²

66. The Presiding Judge stated that TANC’s witness added data points with zero data to his original life tables, which make it more likely that his mathematical and visual

¹⁴⁵ *Id.* PP 225-232.

¹⁴⁶ *Id.* P 223.

¹⁴⁷ *Id.* P 236.

¹⁴⁸ *Id.* PP 242-247.

¹⁴⁹ *Id.* P 212 (citing Ex. TNC-0005 at 33:18-22; Ex. S-0001 at 28:7-29:5; Ex. PGE-0045 (Rebuttal Testimony of Ned W. Allis) at 59:1-4).

¹⁵⁰ *Id.* PP 250-251.

¹⁵¹ *Id.* PP 252-254.

¹⁵² *Id.* PP 255-262.

comparisons will favor Iowa Curves that dictate longer average remaining lives and, therefore, lower depreciation rates, while PG&E's decisions to exclude selected data points beyond certain ages invariably favor Iowa Curves that dictate shorter average remaining lives and, therefore, higher depreciation rates.¹⁵³ Specifically, the Presiding Judge observed that PG&E's witness effectively disregards from 20 to 56 data points in his curve-fitting analysis of the nine disputed accounts.¹⁵⁴

67. The Presiding Judge explained that the National Association of Regulatory Utility Commissioners' 1996 publication, *Public Utility Depreciation Practices* (NARUC Manual), provides an authoritative reference for determining when exclusions of data, called "Truncation Cuts" or "T-cuts", are advisable and when they are not.¹⁵⁵ The Presiding Judge stated that PG&E's assigning less importance to certain data points is equivalent to eliminating them by T-cut.¹⁵⁶ The Presiding Judge explained that the purpose of T-cuts is to remedy irregular dispersion patterns and other irregularities, and that the NARUC Manual places principal emphasis on bimodality, which occurs when retirements hit a second peak in the frequency of retirements, each with its own mode.¹⁵⁷ The Presiding Judge stated that the NARUC Manual identifies two ways in which T-cuts can undermine the reliability of a service life analysis and should not be used: (1) a T-cut that excludes only a few ages can change the shape and remaining life of the best fit curve; and (2) T-cuts can create a "stub curve," which is an observed survivor curve that does not reach 0% surviving.¹⁵⁸ The Presiding Judge noted that the NARUC Manual also states that problems are exacerbated when the T-cut occurs near the mode of the retirement frequency curve, i.e., the steepest portion of the survivor curve and therefore, T-cuts near or at the mode of the retirement frequency curve should be avoided.

¹⁵³ *Id.* P 275.

¹⁵⁴ *Id.* P 270 & Table 3.

¹⁵⁵ *Id.* PP 276-277 & n.340 (citing Ex. TNC-0217 (excerpts from the NARUC Manual) at 2).

¹⁵⁶ *Id.* P 278.

¹⁵⁷ *Id.* PP 278-280. In statistics, the mode of a data set is the value that appears most often. As relevant here, it is the point, measured in years, when retirements in terms of historic installed costs are most frequent.

¹⁵⁸ Initial Decision, 165 FERC ¶ 63,001 at PP 284-287. The NARUC Manual explains that because the average remaining life is represented by the area under the complete curve, stub curves must be smoothed and extended to 0% surviving. NARUC Manual at 120.

68. The Presiding Judge observed that PG&E's T-cuts create problems against which the NARUC Manual cautions, including making T-cuts at or near the mode of the retirement frequency curve, or making T-cuts before the mode year.¹⁵⁹ The Presiding Judge also stated that the NARUC Manual cautions against the creation of stub curves that do not extend beyond 50% surviving, and noted that a number of PG&E's visual T-cuts occur well above that percentage.¹⁶⁰ The Presiding Judge stated that the Commission requires justifications for exclusions of data made in the course of service life estimates, and that PG&E did not provide adequate justifications for its T-cuts.¹⁶¹

69. The Presiding Judge provided a comparison of the Iowa Curves selected by the participants for each of the nine disputed accounts.¹⁶² The Presiding Judge found that for all nine accounts, PG&E employed T-cuts without adequate justification, which resulted in PG&E selecting Iowa Curves with shorter average remaining lives and thus higher depreciation rates. The Presiding Judge thus concluded that Trial Staff's proposed Iowa Curves were the most appropriate of those proposed for the transmission accounts at issue. The Presiding Judge found that, as a prerequisite to its depreciation rates being deemed just and reasonable, PG&E must recalculate those rates using the average remaining lives that Trial Staff prescribed. The Presiding Judge made similar findings for all of the accounts – that PG&E employed T-cuts without adequate justification.¹⁶³

70. With respect to Account 354 – Towers and Equipment, the Presiding Judge stated that TANC and Trial Staff selected an 86-R2.5 curve, and PG&E selected a 75-R4 curve.¹⁶⁴ The Presiding Judge explained that Trial Staff's mathematical analyses, using

¹⁵⁹ Initial Decision, 165 FERC ¶ 63,001 at PP 288-298.

¹⁶⁰ *Id.* PP 297-299. The Presiding Judge noted that the NARUC Manual allows that creation of such a curve may be permissible if the curve has so few retirements that no placement band meets that test. *Id.* at n.364.

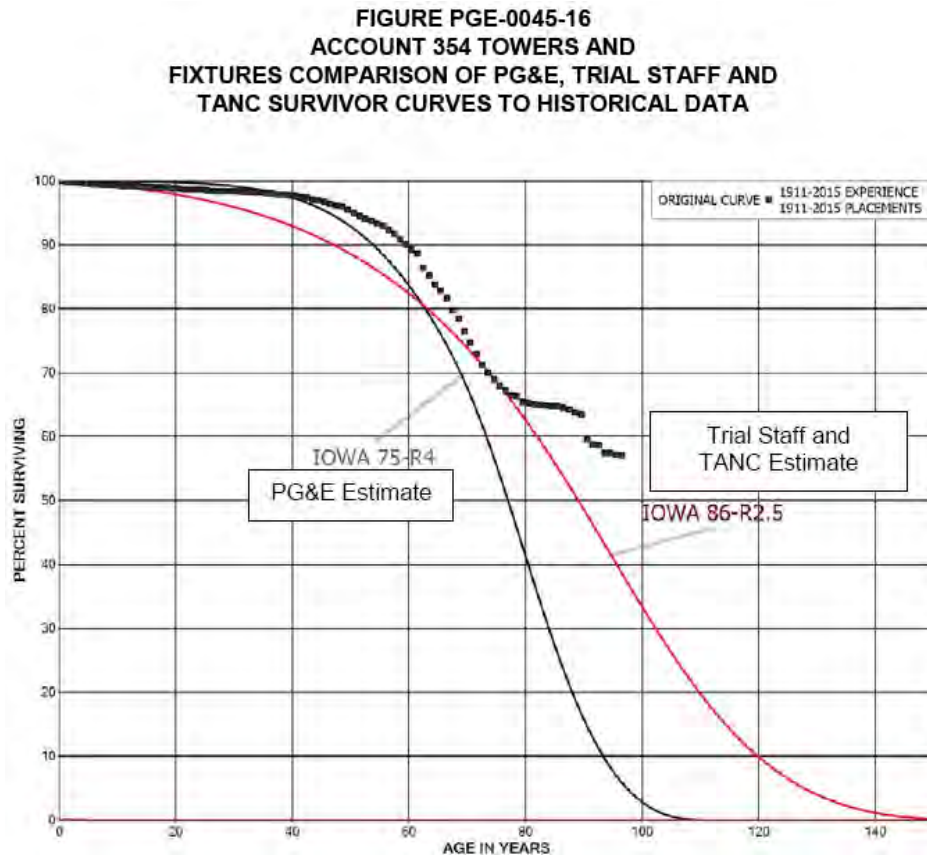
¹⁶¹ *Id.* P 300 & n.366 (citing *S. Cal. Edison Co.*, 53 FERC ¶ 61,408, at 62,428 n.92 (1990) (rejecting average service life estimates where “the selective exclusion of certain of Edison's recorded data has not been justified”) (*1990 SoCal Edison Order*)).

¹⁶² *Id.* PP 310-486. As noted above, all participants agreed to use the same Iowa Curve selected for Account 352.02 as the one selected for Account 352.01.

¹⁶³ We discuss two of the accounts as discussed in the Initial Decision and in our determination below, as they illustrate the rationale that is applicable to all of the accounts.

¹⁶⁴ Initial Decision, 165 FERC ¶ 63,001 at P 360 (citing Ex. TNC-0005 at 39:5-11, 41:3-6; Ex. S-0001 at 28:7-29:5; Ex. PGE-0029 (Workpapers Supporting Ex. PGE-001A)

the actuarial, STAGE and Simulated Plant Record methods, taken together, strongly favor the 86-R2.5 curve.¹⁶⁵ The Presiding Judge included Figure PGE-0045-16 from PG&E's rebuttal testimony, which visually compares the 86-R2.5 curve and the 75-R4 curve with a STAGE observed survivor curve:



71. First, the Presiding Judge stated that a visual comparison of the two curves with a STAGE-observed survivor curve favors the 86-R2.5 curve.¹⁶⁶ Specifically, the Presiding Judge stated that although the 75-R4 curve more closely tracks the original curve through roughly age 62, the 86-R2.5 more closely tracks the original curve through the remaining years, which end at 96.5.¹⁶⁷ Next, the Presiding Judge noted that in the workpapers accompanying direct testimony, PG&E made a T-cut at age 79.5, justified on the ground

at 47)).

¹⁶⁵ *Id.* PP 361-363.

¹⁶⁶ *Id.* PP 364-366.

¹⁶⁷ *Id.* P 365.

that retirement ratios decreased significantly beyond that age.¹⁶⁸ However, the Presiding Judge stated that documents provided by PG&E during discovery showed that 2,683 of PG&E's steel structures are between 104 and 113 years old, and thus rejected PG&E's justification.¹⁶⁹

72. The Presiding Judge stated that PG&E's witness did not point to any dispersion irregularities discussed in the NARUC Manual that might serve as a justification for any of his T-cuts in his written testimony and data responses, but during his cross-examination at hearing, he invoked bimodality as a basis for his disregard of data points beyond a certain age.¹⁷⁰ The Presiding Judge stated that PG&E's witness cited to a large flat area beginning around age 75, arguing that it indicated bimodality.¹⁷¹ However, the Presiding Judge found that PG&E's description of bimodality does not comport with the NARUC Manual's definition as "the presence of two peaks on the retirement frequency curve,"¹⁷² i.e., two modes, rather than the existence of two trends in that pattern. The Presiding Judge also concluded that the observed survivor curve for Account 354 fit the description of bimodality contained in the NARUC Manual.¹⁷³

73. Further, the Presiding Judge found that PG&E's witness' "evolving" attempts to defend his T-cut for Account 354 do not survive scrutiny and that his placement of that T-cut disregards the instructions contained in the NARUC Manual.¹⁷⁴ The Presiding Judge stated that PG&E's witness makes his T-cut near the mode year of 79.5, and that this mode year is greater than the 75 year average service life of his selected Iowa Curve. Also, the Presiding Judge stated that although the NARUC Manual cautions against creating stub curves that terminate above 50% surviving, PG&E's witness creates a stub curve that terminates at 67.98% surviving. For these reasons, the Presiding Judge declined to adopt PG&E's proposed 75-R4 curve for this account. The Presiding Judge

¹⁶⁸ *Id.* P 368 and n.441 (citing Ex. PGE-0029 at 49; Ex. TNC-0216 (PG&E Data Response) at 2).

¹⁶⁹ *Id.* P 374 & n.455 (citing Ex. PUC-0161 (PG&E Data Response) Atch03 at tab "Total summary – pareto", columns A-B, line 18).

¹⁷⁰ *Id.* PP 377-378. As noted above, bimodality occurs when retirements hit a second peak in the frequency of retirements, each with its own mode.

¹⁷¹ *Id.* P 379 & n.465 (citing Tr. 1656:13-14 (Allis)).

¹⁷² *Id.* P 380 & n.467 (citing Ex. TNC-0217 at 2).

¹⁷³ *Id.* P 381.

¹⁷⁴ *Id.* PP 382-383.

also stated that because Trial Staff's mathematical analysis strongly favors the 86-R2.5 curve and a visual comparison also favors it, one must conclude that the 86-R2.5 curve best predicts Account 354's future dispersion patterns.¹⁷⁵

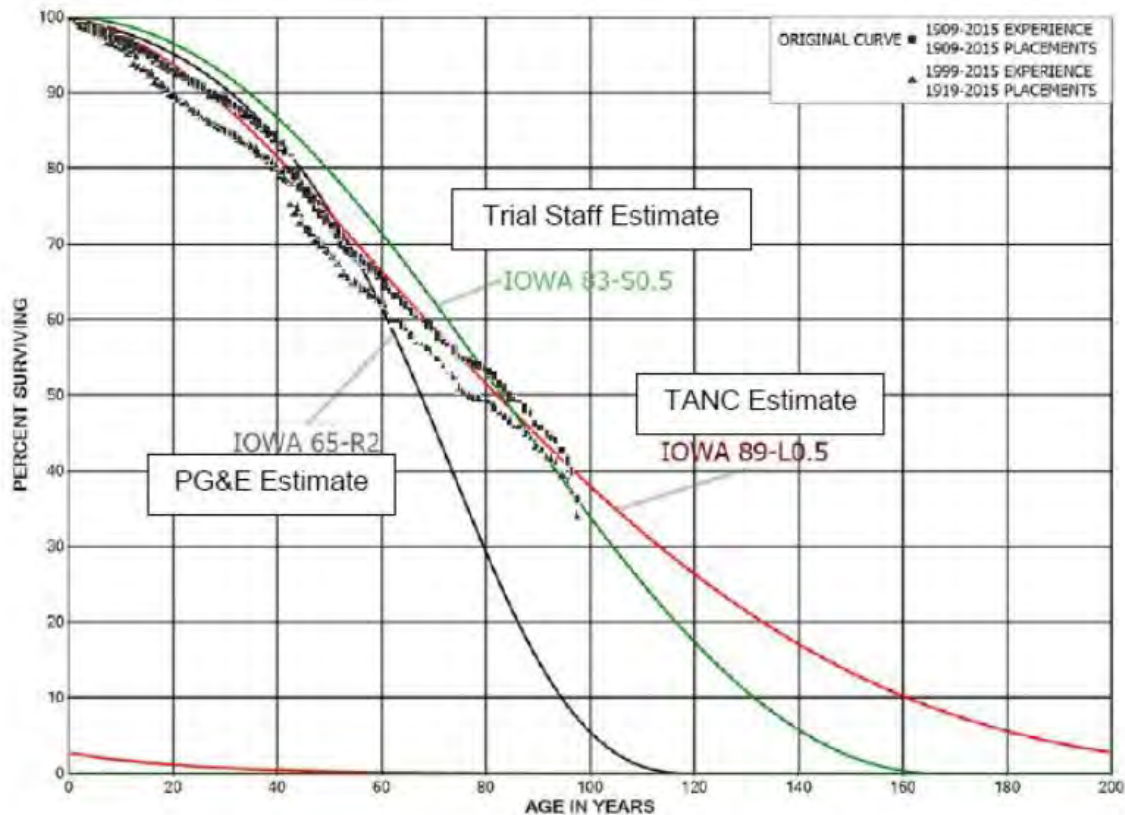
74. With respect to Account 356 – Overhead Conductors and Devices, the Presiding Judge stated that TANC selected an 89-L0.5 curve, Trial Staff selected an 83-S0.5 curve, and PG&E selected a 65-R2 curve.¹⁷⁶ The Presiding Judge stated that Trial Staff's mathematical analyses most favor TANC's 89-L0.5 curve and Trial Staff's 83-S0.5 curve over PG&E's 65-R2 curve.¹⁷⁷ The Presiding Judge included a graph that visually compared the three curves with the observed survivor curves prepared by PG&E using the actuarial and STAGE methods, shown here:¹⁷⁸

¹⁷⁵ *Id.* P 384.

¹⁷⁶ *Id.* P 412 (citing Ex. TNC-0005 at 46:8-10; Ex. S-0001 at 29:6-10; Ex. S-0003 (Supporting Schedules of Kevin J. Pewterbaugh) at 14; Ex. PGE-0029 at 75).

¹⁷⁷ *Id.* P 416.

¹⁷⁸ *Id.* P 418 & n.507 (citing Ex. PGE-0045 at 37&79). The Presiding Judge noted that TANC created this graph in its initial brief by overlaying two graphs in PG&E's witness' rebuttal and that PG&E did not dispute the accuracy of TANC's overlay.



75. The Presiding Judge rejected TANC’s 89-L0.5 curve on two bases, first because it projects a retirement-of-last-unit year that is roughly 2.9 times the average service life of the curve, and second, based on Trial Staff’s un rebutted statement that such a projection is not an accurate forecast of electric transmission plant dispersion.¹⁷⁹ Next, the Presiding Judge stated that the comparison between the two remaining Iowa Curves and the actuarial-observed survivor curve (consisting of triangles) and STAGE-observed survivor curve (consisting of squares) favor PG&E’s 65-R2 curve for the first 70 years and 60 years, respectively. However, the Presiding Judge stated that thereafter, the comparisons favor Trial Staff’s 83-S0.5 curve.¹⁸⁰

76. The Presiding Judge stated that PG&E’s witness, in his direct testimony, made a T-cut at age 60.5, stating in his workpapers that he gave “more consideration” to data points through this age because the data through that age fit “mid-mode R curves” the best, and contending that the later ages showed “a trend toward a lower mode curve with a very long tail”, which in turn indicated “maximum lives far beyond what could

¹⁷⁹ *Id.* P 419.

¹⁸⁰ *Id.* P 421.

reasonably be expected for overhead conductors and devices.”¹⁸¹ The Presiding Judge observed that in his rebuttal testimony, PG&E’s witness took a different tack, stating that “data points through around age 50 should be given more consideration than later data points” and that “data beyond age 50 ... should be given less consideration than that of data up around 50 or 55.”¹⁸² The Presiding Judge stated that, although PG&E’s witness was not clear on whether the T-cut is to be made at age 50.5 or 55.5, he clearly disregarded data points beyond the latter year.

77. In addition, the Presiding Judge found that PG&E first justified T-cuts in general by noting that the value of exposures decreases as the facilities age.¹⁸³ The Presiding Judge stated that although the NARUC Manual acknowledges that a low level of exposures can produce irregularities, he noted that the exposure level for Account 356 is \$62,070,239 at age 55.5, which is not a level that would create dispersion irregularities.¹⁸⁴ The Presiding Judge stated that PG&E further contends that its truncation of data is warranted, because “the retirement pattern begins to change between ages 50 and 60” and “[t]he initial pattern is consistent with the mortality characteristics of the assets in the account, whereas the trend in later ages is not.”¹⁸⁵ The Presiding Judge stated that to demonstrate the alleged change in the retirement pattern, PG&E’s provides a graph that includes all of the historical data points for Account 356, shown here:¹⁸⁶

¹⁸¹ *Id.* P 423 & n.510 (citing Ex. PGE-0029 at 75).

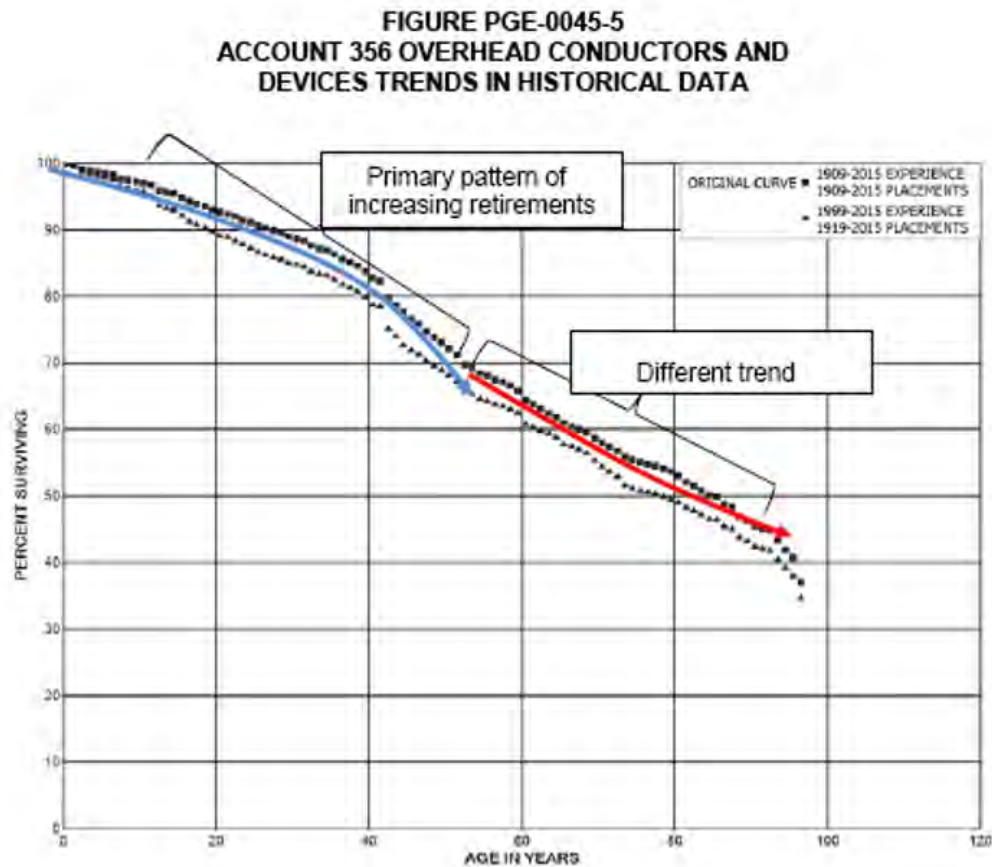
¹⁸² *Id.* P 424 & nn.511, 512 (citing Ex. PGE-0029 at 41).

¹⁸³ *Id.* P 425 & n.513 (citing Ex. PGE-0045 at 39:11-30 (citing Ex. PGE-0029 at 78-79 (original life tables using STAGE method))).

¹⁸⁴ *Id.* P 425.

¹⁸⁵ *Id.* P 426 & n.517 (citing Ex. PGE-0045 at 40:8-12).

¹⁸⁶ *Id.* P 427 & n.518 (citing Ex. PGE-0045 at 40, Figure PGE-0045-5).



78. The Presiding Judge stated that the graph provides no visual support for PG&E's contention that there is a material change in the retirement pattern "between ages 50 and 60" and that a change in the observable trend reflected in the historical data would not justify excluding evidence of that trend from its study.¹⁸⁷ The Presiding Judge found that PG&E's witness provided no evidence of the irregularities cited in the NARUC Manual that might justify his T-cuts, such as bimodality or irregularities due to inadequate exposures. The Presiding Judge explained that PG&E's T-cut is 19.5 data points before the mode of the selected Iowa Curve and therefore can fit any number of curves, and that this problem is exacerbated by the fact that the mode year of the selected curve, 74.5, is appreciably greater than his proposed average service life of 65 years. Accordingly, the Presiding Judge rejected PG&E's T-cut for Account 354.¹⁸⁸

79. The Presiding Judge noted that PG&E claimed that Trial Staff's curve was deficient because it assumed approximately one-third of PG&E's overhead conductors,

¹⁸⁷ *Id.* P 428.

¹⁸⁸ *Id.* P 430.

totaling approximately 6,000 miles, will be in service for more than 100 years. The Presiding Judge stated that PG&E's witness said that "estimate forecasts that over 30% of the assets in the account will be in service more than 100 years, despite that (*sic*) none have actually reached that age."¹⁸⁹ The Presiding Judge asserted that a spreadsheet PG&E provided in response to a CPUC data request contradicted this contention, stating that, as of 2016, 575 of PG&E's transmission overhead conductors had been in service 100 years or longer, some as long as 114 years.¹⁹⁰ The Presiding Judge noted that PG&E argued that the foregoing is a misinterpretation of the spreadsheet, because the data response states that the installation dates of 1900 and 1901 are default dates that PG&E filled in because it lacked the actual dates and that 1910, 1911 and 1912 are typographical errors for 1901.¹⁹¹ However, the Presiding Judge stated that a review of the spreadsheet shows this to be a disingenuous argument, explaining that although the vintage dates 1900 and 1901 appear frequently, the spreadsheet contains numerous other overhead conductors over 100 years old with installation dates not covered by the explanation contained in PG&E's data response, including 1902, 1903, 1906-1909, and 1913-1915, noting that the installation dates 1910-1912 appear infrequently.¹⁹²

80. The Presiding Judge also stated that the assumption that over 6,000 miles of PG&E's transmission overhead conductors will remain in service for more than 100 years is directly supported by PG&E's historical data.¹⁹³ The Presiding Judge explained that age 96.5 is the oldest vintage shown in PG&E's actuarial original life table for Account 356, and the percent surviving associated with that age is 35.16%. The Presiding Judge noted that as of 2016, PG&E had 18,437 miles of overhead conductors, thus 6,000 miles would represent 32.54% of the assets in this account.¹⁹⁴ The Presiding Judge opined that it is reasonable to predict that the percent surviving at age 100.5 will be reasonably close to 32.54%.

¹⁸⁹ *Id.* P 432 & n.522 (citing Ex. PGE-0045 44:6-10).

¹⁹⁰ *Id.* P 433 & n.523 (citing Ex. PUC-0184 (PG&E Data Response); Ex. PUC-0184Atch01 at tab "Transmission OH Conductor").

¹⁹¹ *Id.* P 434 & n.524 (citing PG&E Reply Br. at 67 (citing Ex. PUC-0184Atch01)).

¹⁹² *Id.* P 435 & n.525 (citing Ex. PUC-0184, Att. 01 at tab "Transmission OH Conductor").

¹⁹³ *Id.* P 437.

¹⁹⁴ *Id.* & n.528 (citing Ex. PUC-0107 (PG&E Data Response) at 96).

81. Finally, the Presiding Judge noted that PG&E contended that the foregoing argument is based on one data point, which, in turn, is “based on a very small amount of data for assets that are not representative of PG&E’s current transmission system” and should be eliminated by a T-cut.¹⁹⁵ The Presiding Judge stated that in forecasting percent surviving for years not covered by the original life table, one necessarily starts with the last data point, which will probably exhibit relatively low dollar values for retirements and exposures, and that PG&E does not explain why these dollar amounts should somehow invalidate the forecast of percent surviving and therefore rejected PG&E’s argument on this point. The Presiding Judge then concluded that Trial Staff’s mathematical analyses and PG&E’s visual comparison favor the 83-S0.5 curve, and that curve most accurately predicts the future retirement patterns of Account 356.¹⁹⁶

b. Briefs on Exceptions

82. PG&E argues that the Initial Decision erred by adopting the recommendations of Trial Staff’s witness, who recommended unreasonably long service life parameters that were not supported by the record.¹⁹⁷ PG&E asserts that Trial Staff’s proposals for calculating average service lives would result in PG&E having longer average service lives than similarly-situated utilities in California, namely Southern California Edison Company (SoCal Edison) and San Diego Gas & Electric Company (SDG&E).¹⁹⁸ Next, PG&E argues that the Initial Decision focuses almost exclusively on the mathematical life analyses of each party without giving weight to life estimation, which is based on informed judgment and is supported by the NARUC Manual, adding that PG&E’s witness has physically inspected PG&E’s property, while Trial Staff’s and TANC’s witnesses have not.¹⁹⁹

83. PG&E objects to the Initial Decision’s finding that its witness provided no mathematical analysis to support his Iowa Curve recommendations, arguing that its witness provided detailed mathematical and visual analyses of each plant account in his direct testimony and in responses to numerous data requests.²⁰⁰ PG&E also argues that the Initial Decision erred in interpreting the Commission’s statement in a 1990 SoCal

¹⁹⁵ *Id.* P 438 & n.530 (citing PG&E Reply Br. at 67).

¹⁹⁶ *Id.* P 439.

¹⁹⁷ PG&E Brief on Exceptions at 35.

¹⁹⁸ *Id.* at 36-38.

¹⁹⁹ *Id.* at 39-41.

²⁰⁰ *Id.* at 41 & n.145 (citing Initial Decision, 165 FERC ¶ 63,001 at P 251).

Edison decision as being applicable to the use of T-cuts, contending that the discussion in that decision is related to net salvage analysis rather than life analysis.²⁰¹ PG&E contends that the Initial Decision incorrectly concluded that its witness uses selective information in plotting the graphs for his visual comparison, asserting that he provided graphs using both the actuarial and STAGE methods.²⁰²

84. PG&E also objects to the Initial Decision's finding that no T-cuts should be made for any account, arguing that the NARUC Manual states that careful selection of a T-cut can greatly enhance the reliability of the analysis.²⁰³ PG&E states that the Initial Decision relies on the NARUC Manual advising against making a T-cut at or near the mode of the survivor curve and against using a short stub survivor curve. PG&E contends that considerations such as bimodality and making a T-cut near the mode of the curve are often in conflict and the analyst must use informed judgment to weigh the competing factors and make the most reasonable determination. PG&E argues that its witness considered these factors while Trial Staff's and TANC's witnesses did not.²⁰⁴

85. Next, PG&E takes issue with the Presiding Judge's perception that its witness' technical explanations of his actuarial analysis in discovery, rebuttal, and cross-examination appear to have "evolved."²⁰⁵ PG&E argues that its witness' terminology only slightly changed to describe a significant decrease in retirements, and to explain the meaning of his words used to describe "trends in the data," "leveling-off period," and "bimodality" were the same.²⁰⁶ PG&E asserts that it was appropriate for its witness to make T-cuts to ensure the results of the analyses reflected the most reasonable estimate of the future.²⁰⁷

86. PG&E focuses on Account 354, Towers and Equipment to demonstrate that its T-cuts are appropriate.²⁰⁸ It explains that the discussion of T-cuts in the NARUC Manual is

²⁰¹ *Id.* at 41-42 and n.151 (citing *1990 SoCal Edison Order*, 53 FERC at 62,427-428).

²⁰² *Id.* at 42-43.

²⁰³ *Id.* at 43-46.

²⁰⁴ *Id.*

²⁰⁵ *Id.* at 44.

²⁰⁶ *Id.* at 45.

²⁰⁷ *Id.*

²⁰⁸ *Id.* at 47. PG&E states that it takes exception to the rulings on each account but

in a section on “Data Irregularities,” and contends that PG&E’s data reflects these irregularities.²⁰⁹ It notes that older data for much of its transmission assets are typically things such as lines running to old power houses in the mountains, which its witness claimed were not representative of PG&E’s assets generally and are not subject to upgrades and capacity increases that have happened as the load in California has grown much more significantly over the last 60 years.²¹⁰ In support of this assertion, PG&E depicts a graph for Account 354, indicating the types of data irregularities to which the NARUC Manual speaks.²¹¹ PG&E explains that, from age 75 through age 90, there is a clear leveling-off period followed by another decrease in the curve, representing a “stair step” pattern, and that from age 80 through 100, the data level off and then exhibit a second steeper grade of the curve, demonstrating a second mode and thus bimodality.²¹² PG&E notes that the NARUC Manual advises that it is appropriate to use a T-cut to remove these irregularities. PG&E states that the Presiding Judge relies on the NARUC Manual’s advice that a T-cut should not be made near the mode of the curve. However, PG&E argues that since Account 354 exhibits bimodality, and because the leveling-off and a second mode occurs beginning around age 75, it would be impossible to make a T-cut that eliminates bimodality while also making a T-cut that is not near the mode of the survivor curve.²¹³ PG&E contends that the realities of the historical data for Account 354 mean that not all of the NARUC Manual’s instructions on the use of a T-cut can be simultaneously satisfied, and that PG&E must instead use informed judgment to determine which of the competing instructions is more important – removing bimodality or making a T-cut near the mode of the curve.

87. PG&E asserts that the NARUC Manual recognizes the need to consider all information and make an appropriate, informed determination.²¹⁴ PG&E argues that in

has focused its objections and on support for PG&E’s witness’ use of a T-cut by focusing its discussion and analysis of the rulings for Account 354.

²⁰⁹ *Id.*

²¹⁰ *Id.*

²¹¹ *Id.* at 48.

²¹² *Id.* at 48-50.

²¹³ *Id.* at 51.

²¹⁴ *Id.* at 52 & n.186 (citing Ex. S-0041 (Excerpts from NARUC Manual) at 2). PG&E explains that when discussing stub survivor curves, the NARUC Manual states that “the analyst may be forced to choose between a more reliable longer stub, which by necessity reflects older data, and a less reliable shorter stub, which reflects more recent

this case, elimination of bimodality is more important than avoiding making a T-cut near the mode of the curve.²¹⁵ PG&E therefore argues that the Initial Decision's adoption of Trial Staff's proposals and its rejection of the "informed judgment" provided by its witness as required under the Commission's rules, authoritative depreciation textbooks, and longstanding depreciation practices was clearly improper.²¹⁶ PG&E also objects to the Initial Decision's conclusion that its witness had "no technical training that would allow him to visually or technically understand the life characteristics of transmission equipment," stating that its witness is a trained and certified depreciation expert.²¹⁷

88. Finally, PG&E states that the Initial Decision's adoption of Trial Staff's survivor curves means that the Commission believes that one third of PG&E's overhead conductors - over 6,000 circuit miles of conductor - will be in service for more than 100 years.²¹⁸ PG&E argues that this expectation is inconsistent with both engineering studies and industry information, both of which support maximum lives of these assets in the 80- to 90-year range, and is inconsistent with common sense.²¹⁹

c. Briefs Opposing Exceptions

89. TANC contends that since PG&E did not provide supporting argumentation for its exceptions to the Initial Decision's specific findings on the plant accounts other than Account 354, PG&E has waived its right to challenge any of the Initial Decision's determinations on those nine accounts.²²⁰ TANC and Trial Staff also contend that the Initial Decision thoroughly analyzed the testimony and arguments of all three depreciation witnesses in this case and correctly determined that the Iowa Curves proposed by Trial Staff are the appropriate and reasonable curves for PG&E's transmission plant accounts.²²¹ TANC argues that the conclusion in the Initial Decision

vintages and, therefore, is more likely to reflect the future."

²¹⁵ *Id.*

²¹⁶ *Id.* at 52-53.

²¹⁷ *Id.* at 54 & n.196 (citing Initial Decision, 165 FERC ¶ 63,001 at P 307).

²¹⁸ Although PG&E focuses its arguments on Account 354, this specific argument goes to Account 356 (Overhead Conductors and Devices).

²¹⁹ PG&E Brief on Exceptions at 54-55.

²²⁰ TANC Brief Opposing Exceptions at 54-56.

²²¹ *Id.* at 56-57; Trial Staff Brief Opposing Exceptions at 19-27.

that its witness used selective information in plotting the graphs for his visual comparison is supported by the record evidence.²²² Trial Staff states that it used the most complete set of PG&E's historical data and also applied all of the available mathematical Iowa Curve fitting methodologies to select the best fitting Iowa Curves.²²³

90. TANC and Trial Staff argue that the Commission should reject PG&E's claim that the Iowa Curves need to be consistent with those used by SoCal Edison and SDG&E, arguing that a utility's depreciation rate should be determined through an independent review of that utility's actual historical data rather than other utilities' experience.²²⁴ TANC contends that the Commission should reject PG&E's arguments that the Initial Decision erred in finding that its witness has provided no mathematical analyses to support his Iowa Curve recommendations.²²⁵ TANC notes that the Initial Decision did acknowledge the existence of PG&E's witness' mathematical analyses, but ultimately determined that the analysis did not support his Iowa Curve recommendations. TANC also argues that PG&E is incorrect in its claim that the Initial Decision erred in interpreting the Commission's statement in an earlier decision to the effect that "[t]he Commission requires justifications for exclusions of data made in the course of service life estimates," as being applicable to the use of a truncation cut or T-cut.²²⁶

91. TANC and Trial Staff contend that the Commission should affirm the Initial Decision's finding that PG&E's witness failed to justify the exclusion of significant amounts of PG&E's historical data from his Iowa Curve analysis through the use of T-cuts.²²⁷ TANC contends that PG&E's attempt to justify its T-cut for Account 354 remains unpersuasive and should be rejected for the same reasons provided by the Initial Decision. Trial Staff states that the NARUC Manual makes it clear that T-cuts are only appropriate when needed to exclude unreliable data, but that PG&E's T-cuts remove important actual data, which makes its proposed results unreasonable.²²⁸

²²² TANC Brief Opposing Exceptions at 62-64.

²²³ Trial Staff Brief Opposing Exceptions at 20.

²²⁴ TANC Brief Opposing Exceptions at 58-60; Trial Staff Brief Opposing Exceptions at 21-22.

²²⁵ TANC Brief Opposing Exceptions at 60-64.

²²⁶ *Id.* at 61-62 (citing *1990 SoCal Edison Order*, 53 FERC ¶ 61,408).

²²⁷ *Id.* at 64-69; Trial Staff Brief Opposing Exceptions at 24-27.

²²⁸ Trial Staff Brief Opposing Exceptions at 24-25.

92. Trial Staff explains that the Initial Decision carefully analyzed PG&E's complete set of data to determine whether irregularities made the data unreliable, focusing on the possible existence of bimodality, or the presence of two peaks on the retirement curve. Trial Staff asserts that PG&E's conclusory arguments that bimodality justifies its witness' T-cuts falls far short of the NARUC Manual standard, which states that "[m]inor stair steps or flat areas of curves may be ignored. Where appropriate, *significant* occurrences should be removed from consideration."²²⁹ Trial Staff also states that the Initial Decision correctly acknowledged that T-cuts are not appropriate in situations where a T-cut would occur near the mode of a frequency curve or would result in the creation of a stub curve that does not extend beyond 50% surviving.²³⁰ Trial Staff asserts that PG&E's T-cuts are incorrect for these very reasons, stating that for example, in Account 354, PG&E's witness proposes truncating with nearly 70% surviving and makes his T-cut before the mode, a clear violation of the principles set forth in the NARUC Manual.²³¹ Trial Staff concludes that the Initial Decision correctly found that its proposed Iowa Curves are the most appropriate for PG&E's transmission plant accounts at issue and that PG&E must recalculate a composite depreciation rate based on the average remaining lives prescribed by Trial Staff.²³²

d. Commission Determination

93. We affirm the Presiding Judge's determination that Trial Staff's proposed Iowa Curves are the most appropriate for all of the transmission accounts at issue. Our review indicates that the Presiding Judge thoroughly analyzed the record evidence presented by participants in determining which Iowa Curves are the best fit in calculating PG&E's depreciation rates. As an initial matter, with respect to PG&E's assertion that the Initial Decision erred in finding PG&E's witness provided no mathematical analyses, we disagree. The Initial Decision did not find that PG&E's witness provided no mathematical analyses, as PG&E claims; rather the Initial Decision observed the witness' performed mathematical computations ranking Iowa Curves on a least squared basis. However, as discussed below, we find that the witness did not use the results of those analyses for his average service life recommendations. Indeed, PG&E's recommended Iowa Curves were typically located to the left of the truncated original curve (based in part on historical data), which reduces the average service life and results in an increase in the depreciation expense. For the reasons discussed below, we agree with the

²²⁹ *Id.* at 25 & n.82 (citing NARUC Manual at 122 (emphasis added); Ex. TNC-0217 at 2).

²³⁰ *Id.* at 25-26.

²³¹ *Id.* at 26-27.

²³² *Id.* at 27.

Presiding Judge that PG&E's explanations of irregularities in the original curves and justifications for its truncations of data were not persuasive.

94. PG&E argues that the Initial Decision should have given more weight to its service life estimation, which was based on the informed judgment of its witness, who PG&E argues has physically inspected PG&E's property, while Trial Staff's and TANC's witnesses have not. However, as the Presiding Judge observes, PG&E's witness admits that he has visited less than one percent of PG&E's key transmission facilities and admits that he has no technical training that would allow him to visually or technically understand the life characteristics of transmission equipment.²³³ As explained below, we believe that there is adequate support in the record to adopt the service lives recommended by Trial Staff's witness and TANC's witness and this is consistent with the NARUC Manual.²³⁴

95. We also find unpersuasive PG&E's claim that the Iowa Curves need to be consistent with those used by the other investor-owned utilities in California (SoCal Edison and SDG&E). The Presiding Judge stated that, to the extent PG&E is similarly situated with certain other utilities, PG&E's historical dispersion patterns provide a better predictor of its future dispersion patterns than the dispersion patterns of other utilities.²³⁵ We agree. A principal consideration was whether the data in the record is sound and can be used to determine the appropriate Iowa Curves (as advocated by Trial Staff), or if the data is flawed, making it appropriate to exclude significant amounts of older data in determining appropriate Iowa Curves (as advocated by PG&E). While it is acceptable to use data from other utilities if the utility's historical data is lacking or flawed,²³⁶ the record in this proceeding for many of the accounts contains over 100 years of data,²³⁷ and we find that the Presiding Judge carefully examined this record in reaching his conclusions. Moreover, we find that the original life tables provided by PG&E represent

²³³ Initial Decision, 165 FERC ¶ 63,001 at PP 306-307.

²³⁴ NARUC Manual at 128.

²³⁵ *Id.* P 375.

²³⁶ In addressing net salvage values proposed by PG&E and Trial Staff, the Presiding Judge did consider whether values were "in line" with similarly situated SoCal Edison and SDG&E, because no parties in the proceeding accepted PG&E's net salvage data as flawless.

²³⁷ PG&E's plant is grouped in various accounts or asset classes. For most of the asset classes, PG&E provided continuous records of retirements from 1909 through 2015. See Ex. PGE-0010A at 10; Ex. PGE-0029 (showing original life tables with data from 1909 to 2015 for many of the accounts).

a reasonable underlying data set because PG&E used, among other tools, the actuarial method, which the NARUC Manual states is the preferred approach.²³⁸

96. When the Presiding Judge asserted that a spreadsheet PG&E provided in the hearing in response to a CPUC data request stated that, as of 2016, 575 of PG&E's transmission overhead conductors had been in service 100 years or longer, some as long as 114 years,²³⁹ PG&E argued that the foregoing was a misinterpretation of the spreadsheet, because the record evidence states that the installation dates of 1900 and 1901 are placeholder dates that PG&E reflected because it lacked the actual dates and that years reflected as 1910, 1911 and 1912 are typographical errors for the year 1901.²⁴⁰ The Presiding Judge stated that a review of the spreadsheet showed this to be a disingenuous argument, explaining that although the vintage dates 1900 and 1901 appear frequently, the spreadsheet reflected numerous other overhead conductors over 100 years old with installation dates not covered by the explanation contained in PG&E's record evidence, including 1902, 1903, 1906-1909, and 1913-1915, noting that the installation dates 1910-1912 appear infrequently.²⁴¹ PG&E made no other claims that the historical data were flawed or incorrect.²⁴² Therefore, we find that both Trial Staff and the Initial Decision correctly relied on PG&E's actual historical data for determining the appropriate average service lives for the accounts at issue.

97. With respect to the "informed judgment" of PG&E's witness, the Presiding Judge addressed his informed judgment when the witness asserted that the design of certain assets in the account have changed in ways that support a shorter average service life.²⁴³

²³⁸ The NARUC Manual states that actuarial methods yield more reliable results though they require more detailed data than other methods. NARUC Manual at 81, 111.

²³⁹ Initial Decision, 165 FERC ¶ 63,001 at P 433 & n.523 (citing Ex. PUC-0184 (PG&E Data Response); Ex. PUC-0184Atch01 at tab "Transmission OH Conductor").

²⁴⁰ *Id.* P 434 & n.524 (citing PG&E Reply Br. at 67 (citing Ex. PUC-0184Atch01)).

²⁴¹ *Id.* P 435 & n.525 (citing Ex. PUC-0184, Att. 01 at tab "Transmission OH Conductor").

²⁴² We note that PG&E did not squarely assert in its Brief on Exceptions that the historical data were flawed and thus it arguably waived this argument. See 18 C.F.R. § 385.711(c)(2) (2020) (arguments not raised on exceptions to an initial decision are waived). Nonetheless, we address the arguments PG&E raised at hearing on this issue.

²⁴³ Initial Decision, 165 FERC ¶ 63,001 at PP 341-343.

The Presiding Judge explained that in *Southern California Edison*,²⁴⁴ the Commission made clear that service life estimates must be based on more than mere conjecture. In discussing Account 354 (Towers and Fixtures), PG&E's witness acknowledges that most of the best fitting curves have average service lives of 80 years or more – longer than typical estimates of other utilities. He also avers that “higher mode curves are reasonable for towers, as retirements often occur for an entire line (towers and wires) when the line is upgraded or obsolete.”²⁴⁵ Providing justification for his recommended average service life of 75 years, study relied upon by PG&E's witness' explains that older towers were made of lattice steel and newer towers are more often tubular and made with galvanized steel. Noting that PG&E has no plans to paint its lattice towers, PG&E's witness states that although the 500 kV lines are younger in age (35 to 50 years), the towers may not last as long as the older 230 kV lines because the design of the 500 kV towers requires more maintenance.²⁴⁶ We find PG&E's witness' assertions are speculative and will reject them.²⁴⁷

98. Next, we find that PG&E is incorrect in its claim that the Initial Decision erred in interpreting the Commission's statement in the *1990 SoCal Edison Order* to the effect that “[t]he Commission requires justifications for exclusions of data made in the course of service life estimates,” as being applicable to the use of a T-cut. PG&E claims that the discussion in the *1990 SoCal Edison Order* is related to net salvage analysis rather than life analysis, and does not establish precedent with regard to the use of a T-cut. However, we find that the relevant discussion in that order involved SoCal Edison selecting an Iowa Curve using historical data, then shortening the average service life by six years to account for various alleged life-shortening factors. The Commission rejected SoCal Edison's downward adjustment to average service life, finding that selective exclusion of certain of SoCal Edison's recorded data had not been justified.²⁴⁸ We conclude that the Commission's reasoning in the *1990 SoCal Edison Order* is relevant to the selection of the appropriate Iowa Curve in determining PG&E's depreciation rates.

²⁴⁴ *Southern Cal. Edison Co.*, 38 FERC ¶ 61,040, at 61,107 (1987).

²⁴⁵ Exhibit PGE-0029 at page 47 of 122.

²⁴⁶ *Id.*

²⁴⁷ For example, the record includes a 2010 study by Quanta Technology (Quanta Report), commissioned by PG&E as part of its development of a maintenance and inspection program for its steel towers, that shows that with proper maintenance and repairs, PG&E's towers and structures have been shown to be capable of providing service for well over 100 years.

²⁴⁸ See *1990 SoCal Edison Order*, 53 FERC at 62,428 n.92.

99. We agree with the Initial Decision that PG&E has not supported its use of T-cuts. PG&E contends that not all of the NARUC Manual's instructions on the use of a T-cut can be simultaneously satisfied, and that PG&E must instead use informed judgment to determine which of the competing instructions is more important – removing bimodality or making a T-cut near the mode of the curve. However, the NARUC Manual is clear that T-cuts are only appropriate when needed to exclude unreliable data, such as bimodality, and thus careful selection of a T-cut can greatly enhance the reliability of the resulting analysis. As the Presiding Judge stated, PG&E's T-cuts for a number of accounts contravene the instructions contained in the NARUC Manual because they are too close to the mode, or are before the mode even though the mode year is greater than the average service life.²⁴⁹ In addition, the NARUC Manual also cautions against the creation of stub curves that do not extend beyond 50% surviving, but the record shows that a number of PG&E's visual T-cuts occur well above that percentage.

100. Finally, we agree with the findings in the Initial Decision, and the NARUC Manual that caution against considering minor stair steps or flat areas of curves that may be ignored. We first note that PG&E's witness in his written testimony and data responses did not point to any data dispersion irregularities and only during his cross-examination did he invoke bimodality as a basis for his disregard of data points.²⁵⁰ We agree with the Presiding Judge and Trial Staff that PG&E has not supported any bimodality with respect to age. Rather than one or two minor "stair steps" that should be ignored, a mode on a standard retirement frequency curve should dominate several years on either side of the mode with significant retirement experience. However, we do agree with the evidence provided in the Quanta Report that PG&E's 500 kV lines are unique and cannot be compared with other voltage levels and that PG&E's transmission assets experience locational bimodality (explained below). Nonetheless, we find that PG&E's witness failed to provide or support any bimodal retirement frequency curve nor demonstrate any bimodality with respect to age.

101. We note that PG&E's specific arguments in its Briefs on Exceptions focus on Account 354 (Towers and Fixtures), explaining that these arguments applied to all accounts at issue.²⁵¹ In this order, we specifically discuss Account 354 below, as well as Account 356 (Overhead Conductors and Devices), to demonstrate the flaws in PG&E's reasoning. As discussed further below, the flaws in PG&E's reasoning for these two accounts are very similar to the other accounts and thus our determinations with respect

²⁴⁹ Initial Decision, 165 FERC ¶ 63,001 at PP 290-296.

²⁵⁰ *Id.* P 377.

²⁵¹ As noted above, PG&E makes one argument about Account 356 (Overhead Conductors and Devices).

to these two accounts are equally applicable to all of the accounts at issue in this proceeding.²⁵²

102. For Account 354, TANC and Trial Staff selected an Iowa Curve with an 86-year average service life, while PG&E chose one with a 75-year average service life. The Presiding Judge noted that PG&E's witness had chosen to plot only a STAGE observed survivor curve (original) and, in performing this analysis, he had excluded a substantial number of historical data points (specifically, 21 data points from Ages 75.5 to 96.5).²⁵³ In his rebuttal testimony, PG&E's witness justified the truncation on the grounds that the smaller level of exposures beyond age 75 can result in more erratic movement making these older data points less reliable, and the trend in the data beyond age 75 was not consistent with the assets in that account.²⁵⁴ Specifically, PG&E's witness argued that he expected retirements in Account 354 to increase after age 75, not decrease, and for the assets generally to be retired by age 100.²⁵⁵

103. The record evidence in this proceeding undermines PG&E's assumption. Notably, Exhibit PUC-0161, which PG&E provided in discovery, shows that 2,683 of PG&E's steel structures are between 104 and 113 years old.²⁵⁶ Our review of Exhibit No. PUC-0161Atch3 indicates that 11,956 of PG&E's steel structures are aged 88.5 years or older.²⁵⁷ Based on PG&E's claims, these structures are approaching imminent retirement and are at the end of their service life; however, the discovery response also included a document by Quanta Technology²⁵⁸ that states steel structures are durable assets with

²⁵² Because we find our reasoning with respect to Accounts 354 and 356 is applicable to all of the accounts in dispute, we do not address TANC's argument that PG&E's decision to address only Account 354 means that PG&E has waived its right to challenge the Initial Decision's determinations regarding those other accounts.

²⁵³ See *id.* P 270, Table 3.

²⁵⁴ Ex. PGE-0045 at 73.

²⁵⁵ *Id.*

²⁵⁶ Initial Decision, 165 FERC ¶ 63,001 at P 374 & n.455 (citing Ex. PUC-0161 Att. 03).

²⁵⁷ See Ex. PUC-0161 (PG&E Data Response) Atch03 at tab "Total summary – pareto" lines 3-5.

²⁵⁸ Quanta Technology is a PG&E contractor that in 2010 assisted PG&E in designing a maintenance and inspection program for PG&E's steel towers.

long service-life capabilities if properly maintained.²⁵⁹ The document states that the predominant practice in the industry for management of structures is to repair or refurbish structures and components. The document acknowledges that the question of refurbishment or replacement of a structure is largely an economic decision dependent on the degree of deterioration or damage present. As pertinent here, the document states that “the long expected service life of structures, the durability of materials, and the ability to replace parts of the structure or reinforce a foundation, drive a predominant philosophy of repair or refurbish.”²⁶⁰ The Quanta Report also analyzed data for PG&E’s steel structure failures by Damage Type.²⁶¹ The report states that the most frequent age of structure failures²⁶² is around age 40 in the Worn/Aged category, age 50 in the Buckled/Bent category, and age 75 in the Rusted category. However, these Damage Types can occur at any time during a property unit’s life. In addition, the depreciation analyses performed by PG&E’s witnesses ignore all of the steel towers and structures that were installed and have been properly maintained for over 100 years. Accordingly, we disagree with PG&E that their data show any type of irregularities or bimodality after the age of 75 years.

104. PG&E states that the NARUC Manual discusses T-cuts in a section called “Data Irregularities,” and claims that its data experience the types of irregularities described there.²⁶³ PG&E cites its witness’ testimony, in which he claimed that older data for many of PG&E’s assets are typically things such as lines running up mountains to old power houses which are not representative of PG&E’s assets generally. PG&E’s witness went on to explain that these older assets are not subject to things like capacity upgrades that have happened as the load in California has grown much more significantly over the last 60 years. Thus, PG&E’s witness argued that PG&E’s accounts are not, for the most part, fully homogeneous, as that term is defined in the NARUC Manual.²⁶⁴ While the predominant force of retirement for transmission assets over the last 60 years may have been due to upgrades in capacity or re-conductoring of transmission lines, PG&E’s witness did not address whether this dominant trend reflected in his original curve has been increasing or decreasing and they appear to be decreasing over the last 20 years.

²⁵⁹ See Ex. PUC-0161 and Atch04 – Quanta Technologies on Structures at 5, 27.

²⁶⁰ *Id.* at 55.

²⁶¹ Quanta Report at 41-43.

²⁶² The Quanta Report defines “failure” as an indication that a *component* requires significant maintenance or replacement. Failure, as defined, does not mean the complete failure of a structure.

²⁶³ PG&E Brief on Exceptions at 47.

²⁶⁴ *Id.*

Specifically, these upgrades and reconductoring would appear to be a primary reason for structures and towers that could be maintained for well over 100 years to be retired earlier than necessary in their service life and this dominant retirement force should reduce the expected service life of the other remaining units.

105. Accordingly, we believe that an 86-year average service life is the most accurate because it includes all retirements from PG&E's capacity upgrades and all forces of retirement for an assumed largely homogeneous group because there was no evidence shown for the separation of different modes. Specifically, the data that PG&E chose shows only retirements that occurred during the experience band for the years 1999 through 2015 and for all forces of retirement for the installations that occurred from 1919 through 2015.²⁶⁵ The Commission typically determines depreciation rates by FERC Account unless there is evidence shown for the separation of different modes.²⁶⁶ PG&E has not shown good cause to remove its 500 kV system or older transmission lines from its analyses. Thus, the accounts should be treated as homogeneous for the purpose of determining depreciation rates. Accordingly, we reject PG&E's witness' proposed 75-year average service life as unreliable because he unjustifiably excluded significant historical data. We affirm the Presiding Judge's selection of Trial Staff's proposal, and direct PG&E to use an 86-year average service life as conservative because it more closely reflects use of all the historical data for the last 96 years.

106. For Account 356, TANC selected an Iowa Curve with an 89-year average service life, Trial Staff chose one with an 83-year average service life, and PG&E chose one with a 65-year average service life. We find that PG&E has not supported its proposal to use a 65-year average service life, and that the Presiding Judge's selection of Trial Staff's 83-year average service life is the best fit and the most reasonable selection. The Presiding Judge adequately addressed PG&E's argument that selection of Trial Staff's Iowa Curve will assume that over 6,000 circuit miles of overhead conductor could be in service for more than 100 years. With respect to PG&E's concern that selection of Trial Staff's Iowa Curve will assume that conductors will be in service for over 100 years, this concern is due to the tail end of Trial Staff's selected 86-R2.5 dispersion of retirements. However, only the 86-year average service life is used to determine the average remaining life, which ultimately determines PG&E's depreciation expense. The dispersion of retirements is exceptionally wide due to the inclusion of retirements of

²⁶⁵ Ex. PGE-0029 (Workpapers Supporting Ex. PGE-001A) at 81-83).

²⁶⁶ See NARUC Manual at 19 ("Rather than depreciating each item by itself (unit depreciation) or depreciating one single group containing all utility plant, a group contains homogeneous units of plant which are alike in character, used in the same manner throughout the utility's service territory, and operated under the same general conditions").

conductors necessitated from the re-conductor of transmission lines but significant amounts of exposures remaining in service. Specifically, the Presiding Judge stated that a spreadsheet provided by PG&E showed that, as of 2016, 575 of PG&E's transmission overhead conductors had been in service for 100 years or longer, some as long at 114 years.²⁶⁷ However, these 575 strands of conductor were not included the analyses of PG&E's witness.

107. The Presiding Judge noted that 96.5 years was the oldest vintage in PG&E's witness' actuarial life tables for Account 356, and the percent surviving associated with that age is 35.16%.²⁶⁸ PG&E's witness truncated 36 data points (from ages 60.5 – 96.5)²⁶⁹ for this account, explaining that this data was not representative of PGE's transmission system at large. However, PG&E demonstrated no difference between conductor installations over 60 years old or any reason why newer conductor installations could not last as long as the installations that were truncated.

108. PG&E also argues that the 83-year average service life used in Trial Staff's proposed Iowa Curve is inconsistent with both engineering studies and industry information which support maximum lives of these assets in the 80- to 90-year range.²⁷⁰ However, we find that Trial Staff's proposed Iowa Curve with an 83-year average service life is properly within that range. PG&E has not shown any plans to remove large amounts of conductor installations because they have reached the end of their service life and as noted above, its data show that conductors can last more than 100 years. The 83-year average service life reflects the best fit curve for the actuarial data for Account 356 and includes 60 years of re-conductor retirements from PG&E's significant load growth along with all other forces of retirement. Therefore, we affirm the Presiding Judge's selection of Trial Staff's 83-year average service life for Account 356 because it more closely reflects use of all the historical data

109. As to why PG&E's steel structures could last longer than the structures of other California utilities, another PG&E witness states "the length of time that a steel structure could stay in-service is dependent on the characteristics of the location in which that structure is installed."²⁷¹ The evidence in the Quanta Report also supports that PG&E's

²⁶⁷ Initial Decision, 165 FERC ¶ 63,001 at P 433 & n.523 (citing Ex. PUC-0184; Ex. PUC-0184 Att. 01 at tab "Transmission OH Conductor").

²⁶⁸ *Id.* P 437.

²⁶⁹ *Id.* P 270 and Table 3.

²⁷⁰ PG&E Brief on Exceptions at 55.

²⁷¹ Tr. at 1394 (PG&E witness Dasso).

existing steel structures have shown to have average service that are considerably greater than average industry data. Specifically, having studied 796 PG&E records, the Quanta Report concluded that transmission structures located in a coastal region to have peak age [mode] failure of about 60, with the peak age failure for structures in a valley or mountain region about 70.

110. As noted by the Presiding Judge, 96.5 years was the oldest vintage in PG&E's witness' actuarial life tables for all nine disputed accounts. Further, PG&E's witness effectively disregards through his use of T-cuts from 20 to 56 data points in his curve-fitting analysis of the nine accounts.²⁷² His Iowa Curve recommendations typically went through the data until his T-cuts, and then abruptly shifted to the left and downward, which project significant retirement experience, shorter average service lives and average remaining lives, and thus higher proposed depreciation rates. We agree with the Presiding Judge that PG&E's witness' T-cuts for all of the accounts run contrary to the guidance set forth in the NARUC Manual, for example by being too close to or before the mode or resulting in stub curves that do not extend beyond 50% surviving. We agree that PG&E's witness has provided no evidence of the irregularities cited in the NARUC Manual that might justify the foregoing T-cuts, such as bimodality or irregularities due to inadequate exposures. Accordingly, we find that PG&E failed to support its proposed Iowa Curves and affirm the Presiding Judge's determination that Trial Staff's proposed Iowa Curves are the most appropriate for all of the transmission accounts at issue and will produce depreciation rates that are just and reasonable. We therefore direct PG&E to recalculate its proposed depreciation rates on compliance using the average remaining lives that Trial Staff's witness prescribes.

2. Net Salvage and Cost of Removal Ratios

111. Net salvage value is the remaining value of a retired property less the cost incurred to decommission and remove the property. The net salvage ratio is the net salvage value divided by the original cost of the facility being retired, expressed as a percentage.²⁷³ Net salvage ratios are frequently negative because the cost of removing property often exceeds its salvage value at retirement. Negative net salvage ratios increase the overall depreciation expense that must be collected over the useful life of such property.²⁷⁴ The Commission has previously cited the guidelines for depreciation set forth in the NARUC

²⁷² Initial Decision, 165 FERC ¶ 63,001 at P 270 & Table 3.

²⁷³ NARUC Manual at 322; *see also* Initial Decision, 165 FERC ¶ 63,001 at PP 489-490. Hereafter, we will not include the "percent" unit to describe net salvage ratio values.

²⁷⁴ Initial Decision, 165 FERC ¶ 63,001 at P 490.

Manual.²⁷⁵ For net salvage calculation, the NARUC Manual suggests that past salvage and cost of removal data be used to project future values. It also suggests that data should be adequately quality controlled. For example, if certain transactions are considered to be unrepresentative of the future, they should be removed from the data.²⁷⁶ The Commission has typically accepted analysis that uses the straight-line method of depreciation.²⁷⁷ Additionally, the Commission has previously noted that net salvage ratios must be consistent with costs typically seen in the electric industry.²⁷⁸ To that end, industry data may be considered when determining appropriate net salvage ratios.

112. To determine net salvage ratios, PG&E's witness relied heavily on PG&E's historical data from 1996-2015 and considered three-year moving averages and the most recent five-year averages. PG&E's witness noted that costs of removal have been increasing.²⁷⁹ PG&E's witness then created account-by-account recommendations for the net salvage ratios by coupling the historical data with general trends seen by PG&E.

a. Initial Decision

113. The Presiding Judge stated that PG&E's calculations are generally most likely to replicate PG&E's future experiences. To calculate the historical net salvage ratio for its transmission plants, PG&E used historical data to divide the account's annual net salvage cost by the original cost of the facilities retired. PG&E's witness used multiple methodologies to calculate annual net salvage ratios for 1996-2015, including a 20-year average, three-year rolling averages, and a five-year average for 2011-2015. The Presiding Judge concluded that PG&E's methodology is consistent with Commission methodology.²⁸⁰ Although Trial Staff's witness argued that PG&E's witness recommends lower net salvage ratios than historical experience would dictate, the Presiding Judge concluded that PG&E's witness had used historical experience to conservatively adjust the net salvage ratios.

²⁷⁵ See, e.g., *Entergy Servs. Inc.*, 142 FERC ¶ 61,022 at P 40 (2013) (*Entergy Services*).

²⁷⁶ NARUC Manual at 157-164.

²⁷⁷ *Depreciation Accounting*, Order No. 618, 92 FERC ¶ 61,078 (2000).

²⁷⁸ See *Entergy Services*, 143 FERC ¶ 61,116 at P 113.

²⁷⁹ Ex. PGE-001A (Testimony of Ned W. Allis) at 36-41.

²⁸⁰ Initial Decision, 165 FERC ¶ 63,001 at PP 489-501.

114. The Presiding Judge explained that TANC's witness applied two methodologies to calculate net salvage ratios, one consistent with Commission precedent and another method that is non-traditional.²⁸¹ TANC's witness considered the net salvage ratios of 82 companies, reviewing the maximum and minimum net salvage ratios, and the mean, mode, and average ratios. The Presiding Judge observed that TANC's methodology gives more weight to the historical data which TANC's witness perceived to be more reliable.²⁸² However, the Presiding Judge also observed that the companies reflected in TANC's industry analysis did not include any utilities that operate inside California.²⁸³

115. The Presiding Judge next explained Trial Staff's assertion that PG&E's historical data was insufficient, and therefore the net salvage ratios of other companies should be considered. Trial Staff used industry comparisons for 22 companies to calculate the industry average for specific accounts. Trial Staff also examined the historical data provided by PG&E's witness, removed outliers from historical data, and then compiled 20-year average net salvage ratios for each account.²⁸⁴ The Presiding Judge noted that while two California utilities were included in Trial Staff's analysis, they made up only a small percentage of the total industry analysis.²⁸⁵

116. The Presiding Judge rejected several of TANC's arguments. TANC maintained that PG&E's historical data is too flawed to support PG&E's analysis.²⁸⁶ Based on conclusions drawn from a review of workpapers which that accompanied PG&E's witness, TANC contended that PG&E's historic data frequently shows removal costs associated with no retirement assets, as well as negative cost of removal and negative gross salvage values. The Presiding Judge concluded that TANC's counsel was not qualified to review the data and recordkeeping irregularities from an internal audit and how those might bear on a depreciation analyst's ability to use historical data on which those workpapers are based. Further, the Initial Decision noted that TANC's testimony did not raise data concerns, and therefore PG&E was unable to address such concerns in its rebuttal testimony.²⁸⁷ The Presiding Judge also asserted that almost all industry

²⁸¹ *Id.* P 496 (citing Ex. TNC-0005 (Testimony of James Garren)).

²⁸² *Id.* PP 495-497.

²⁸³ *Id.* P 512.

²⁸⁴ *Id.* PP 493-500.

²⁸⁵ *Id.* P 511.

²⁸⁶ *Id.* P 505.

²⁸⁷ *Id.* PP 505-508.

statistics used by Trial Staff and TANC consisted of companies operating outside of California, making them difficult to compare to PG&E. The Presiding Judge noted that PG&E's witness stated that California has higher labor costs and more stringent environmental regulations, which can result in higher removal costs.²⁸⁸

117. The Presiding Judge then considered an account-by account analysis. For Account 352.01 & 352.02, Structures and Improvements, the Presiding Judge determined PG&E's and Trial Staff's net salvage ratio of negative 20%, or (20),²⁸⁹ most appropriate, noting the similarity to SoCal Edison's and SDG&E's values for the same accounts. For Account 353.01, Station Equipment, the Presiding Judge proposed a net salvage of (60), preferring PG&E's methodology and noting that the net salvage ratio is in line with SDG&E's salvage ratio for the same account. For Account 353.02, Step up Transformers, the Presiding Judge stated that historical data should take precedence which the data is adequate and found Trial Staff's recommended net salvage ratio of (1) best suits the account. For Account 354, Towers & Fixtures, the Presiding Judge determined PG&E's witness recommended ratio of (100) is most appropriate, again noting the value is in line with SoCal Edison's and SDG&E's net salvage values for the same account. For Account 355, Poles & Fixtures, the Presiding Judge accepted PG&E's proposed net salvage value of (80), finding the ratios are in line with SoCal Edison's and SDG&E's values for the same account. For Account 356, Overhead Conductors & Devices, the Presiding Judge again determined PG&E's net salvage ratio of (110), finding the value is comparable to SoCal Edison's and SDG&E's values for that account. For Account 357, Underground Conduit, the Presiding Judge approved a net salvage ratio of 0, which aligned with proposals of PG&E, Trial Staff and TANC. For Account 358, Underground Conductors & Devices, the Presiding Judge found Trial Staff's proposed net salvage ratio of (14) is best suited to the account and noted the ratio is between those of SoCal Edison's and SDG&E's values for the same account. For Account 359, Roads & Trails, the Presiding Judge supported PG&E's proposed ratio of (10), noting the values are in line with the average net salvage ratios for 1996-2015.²⁹⁰ Upon reviewing all accounts, the Presiding Judge determined that PG&E must use the methodology proposed by Trial Staff's witness to recalculate its depreciation rates for Account 353.2, Step-Up Transformers, and Account 358, Underground Conductors and Devices.²⁹¹

118. When assessing the non-traditional methods proposed to calculate net salvage ratios, the Presiding Judge rejected TANC's argument that the traditional method of

²⁸⁸ *Id.* PP 509-513.

²⁸⁹ Hereafter, we refer to negative net salvage ratios in parentheses.

²⁹⁰ *Id.* PP 514-561.

²⁹¹ *Id.* P 577.

determining net salvage ratios overcharges current customers. TANC's witness proposed calculating the account's average annual net salvage value for the most recent five years and then multiplying it by the average remaining life of the account's facilities. To calculate net salvage ratio, the net salvage amount would then be divided by the original cost of the facilities. The Presiding Judge supported Trial Staff's explanation that PG&E is collecting amounts that should enable it to recover the costs that will be incurred to retire the account's facilities in the future, and are not designed to match current costs. The Presiding Judge concluded that using TANC's approach would result in recovering far less than the original cost for the account's facilities.²⁹²

119. SWP proposed a methodology termed the "flat real recovery method" for each account, which aims to provide "intergenerational equity."²⁹³ SWP contended that current customers are subsidizing future customers because, while straight-line depreciation is captured equally over a period of time, the present value of money exceeds the future value due to inflation. The Presiding Judge rejected SWP's methodology, noting that the Commission has endorsed straight-line depreciation and that straight-line methodology is widely used.²⁹⁴ Further, the Presiding Judge pointed to Trial Staff's rationale that this methodology introduces uncertainty into the depreciation calculation, and the proposed salvage cost allocation is inconsistent with the allocation of other depreciation expenses.²⁹⁵

b. Briefs on Exceptions

120. TANC argues that the Initial Decision erroneously excused PG&E from satisfying its burden of proof to fully justify its proposed net salvage estimates.²⁹⁶ TANC notes that the Presiding Judge found counsel unqualified to discuss irregularities in PG&E's data. TANC maintains that the data used by PG&E's witness is not only unreliable, but numerous data entries in the net salvage calculations are not possible. For example, TANC points to removal costs being recorded for years in which there were no retirements and cites numerous deficiencies found by PG&E's internal audits, such as

²⁹² *Id.* PP 562-566.

²⁹³ See Ex. SWP-0001 (Testimony of David Marcus) at 12-16.

²⁹⁴ We note that no briefs were filed in support of SWP's proposed technique or the Presiding Judge's determination to dismiss the approach.

²⁹⁵ Initial Decision, 165 FERC ¶ 63,001 at PP 567-576.

²⁹⁶ TANC Brief on Exceptions at 46-47.

misstated plant and accumulated depreciation balances.²⁹⁷ TANC disagrees with the Presiding Judge's determination that TANC's depreciation expert did not discuss PG&E's recordkeeping irregularities in his testimony, which precluded PG&E from addressing such concerns on rebuttal. TANC contends that PG&E was given the opportunity to defend the quality of its data and address concerns on its accuracy.²⁹⁸

121. TANC also takes exception to the Initial Decision's and PG&E's reliance on the net salvage ratios of SoCal Edison and SDG&E to support PG&E's calculations, maintaining that PG&E's data is out of line with the other California utilities. TANC notes that the most recently authorized net salvage values for SoCal Edison and SDG&E are not found in the record, and request that the Commission take official notice of the most recent authorized values.²⁹⁹ TANC provides a table that illustrates that, for six accounts, the net salvage ratios calculated using PG&E's historical data exceed the authorized values for SoCal Edison and SDG&E. TANC then compares the net salvage ratios accepted by the Initial Decision to those of SoCal Edison and SDG&E, demonstrating that the PG&E's ratios exceed those of the other utilities in four of six accounts. TANC also cites the lack of record evidence that explains how the SoCal Edison and SDG&E net salvage ratios were determined.³⁰⁰

122. In its analysis, TANC reiterates that the net salvage ratios accepted by the Presiding Judge exceed that of SoCal Edison and SDG&E for Account 353.01 – Station Equipment, Account 354 – Towers and Fixtures, Account 356 – Overhead Conductors and Devices, and Account 359 – Roads and Trails.³⁰¹ For Account 355 – Poles and Fixtures, TANC notes anomalies in PG&E's data as well as the comparison to outdated SDG&E and SoCal Edison ratios.³⁰² For Account 358 – Underground Conductors and Devices, TANC notes that the net salvage ratio approved by the Presiding Judge, which was proposed by Trial Staff, exceeds the ratio request by PG&E, and again cites to outdated data in the record for SoCal Edison and SDG&E.³⁰³

²⁹⁷ *Id.* at 48-49.

²⁹⁸ *Id.* at 55-59.

²⁹⁹ *Id.* at 52, 64.

³⁰⁰ *Id.* at 51-53, 62-64.

³⁰¹ *Id.* at 66, 67, 70, 72.

³⁰² *Id.* at 67-68.

³⁰³ *Id.* at 71-72.

123. Trial Staff maintains that PG&E's historical data is flawed and results in net salvage values that are far more negative than the average utility net salvage ratio,³⁰⁴ and contends that the Initial Decision erred in accepting PG&E's net salvage calculations for five accounts. Trial Staff examines how PG&E's net salvage ratios vary significantly from PG&E's historical average.³⁰⁵ Trial Staff also asserts that the industry averages presented by Trial Staff's witness are adequately adjusted by five percentage points to account for the higher costs the Presiding Judge noted in California.³⁰⁶

124. Trial Staff analyzes five accounts in which the Presiding Judge accepted PG&E's net salvage estimates that differed from Trial Staff's.³⁰⁷ For Account 353.01, Station Equipment, Trial Staff's witness stated that much of the equipment is easy to remove and therefore PG&E's proposed net salvage value of (60) is unreasonable. Trial Staff notes that SoCal Edison has a net salvage ratio of (5) for this account, which is even lower than the value of (15) that Staff proposed. Trial Staff notes that a ratio of (60) will collect approximately \$56 million more in depreciation annually than Trial Staff's proposed value of (15)%. For Account 354, Towers and Fixtures, Trial Staff notes that historical data would indicate a net salvage ratio of (146), but PG&E has proposed (100)%, while industry average is just (34). Similarly, for Account 355, Poles and Fixtures, Trial Staff notes that PG&E's witness rejected PG&E's historical data which demonstrated a ratio of (148)%, and instead proposed (80)%. For Account 359, Roads and Trails, Trial Staff notes historical data indicates a ratio of (40)%, but PG&E's witness proposed (10)%.

c. Briefs Opposing Exceptions

125. PG&E contends that TANC and Trial Staff failed to show that the Initial Decision erred in its ruling on PG&E's net salvage values. PG&E asserts that TANC and Trial Staff repeated arguments that the Presiding Judge found unpersuasive. Further, PG&E states that on exceptions, TANC has attempted to introduce new arguments and information that were not in the record, and has mischaracterized information.³⁰⁸ PG&E also maintains that the net salvage calculations adopted by the Initial Decision, which largely follow PG&E's methodology, are superior for several reasons. First, PG&E states that the methodology is endorsed by the NARUC Manual, whereas the approaches

³⁰⁴ Trial Staff Brief on Exceptions at 31.

³⁰⁵ *Id.* at 33.

³⁰⁶ *Id.* at 34.

³⁰⁷ *Id.* at 36-40.

³⁰⁸ PG&E Brief Opposing Exceptions at 55.

of TANC and Trial Staff were unconventional.³⁰⁹ Additionally, PG&E's methodology utilized 20 years of historical, record data, rather than averages of unrelated utilities.³¹⁰ PG&E also argues that it correctly used comparable data from other California utilities, such as SoCal Edison and SDG&E, whereas other methodologies used broader industry averages. PG&E also points to the Presiding Judge's agreement that California has higher costs than industry averages.³¹¹

d. Commission Determination

126. We affirm in part and reverse in part the Presiding Judge's determinations with respect to PG&E's proposed net salvage values. Specifically, we affirm the Presiding Judge with respect to Accounts 352.01 (Structures & Improvements), 352.02 (Structures & Improvements – Equipment), 353.02 (Station Equipment – Step-Up Transformers), and 357 (Underground Conduit), for which no exceptions were filed by the parties. We also affirm the Presiding Judge with respect to accounts 353.01 (Station Equipment), 354 (Towers & Fixtures), 356 (Overhead Conductors & Devices), and 359 (Roads & Trails). However, we reverse the Presiding Judge with respect to accounts 355 (Poles & Fixtures) and 358 (Underground Conductors & Devices). Our determination on each of these accounts is discussed more fully below.

127. We note that the use of historical data to calculate net salvage ratios is appropriate here as it aligns with the methodology reflected in the NARUC Manual.³¹² When it is shown that historical data is insufficient to calculate net salvage ratios, industry data can be considered.³¹³ Trial Staff and TANC object to PG&E's use of historical data to calculate net salvage ratios and instead, favor the use of industry data. We agree with the Presiding Judge that PG&E's historical data is sufficient for the purpose of calculating net salvage values, except as otherwise discussed below.

i. Account 353.01, Station Equipment

128. For Account 353.01, Station Equipment, the Presiding Judge concluded that PG&E's proposed net salvage of (60) for this account was most appropriate. He

³⁰⁹ *Id.* at 38-39.

³¹⁰ *Id.* at 36-40.

³¹¹ *Id.* at 45-46.

³¹² NARUC Manual at 157-158.

³¹³ See *Entergy Services*, 143 FERC ¶ 61,116 at P 113 (references "consistent with costs typically seen in the electric industry").

reasoned that PG&E's recommendation was based on historical data showing that PG&E's net salvage ratio averaged (82) over 20 years and indicated that his conclusion was tempered by Trial Staff's industry statistics showing ratios ranging from 15 to (60). The Presiding Judge also noted that PG&E's proposed net salvage value for this account was in line with the net salvage ratio for SDG&E of (60) for this account and reasoned that (60) is less negative than PG&E's historical 20-year average ratio of (82) and lower than Trial Staff's calculation of an average ratio, based on PG&E's historical data with outliers removed, (78).³¹⁴

129. The Presiding Judge examined and declined to accept Trial Staff's recommendation of (15), which was based on an industry average of (10) adjusted downward to give some recognition to the historical data and TANC's proposed net salvage value based on the threshold for the most negative quartile among companies identified (20). The Presiding Judge reasoned that the industry statistics upon which Trial Staff and TANC witnesses rely provided little support for their positions, observing that none of the companies in TANC's survey are similarly situated to PG&E, and that the number of such companies in Trial Staff's survey was too small to give weight to the industry average.

130. We affirm the Initial Decision on this issue and find that PG&E's proposed net salvage ratio of (60) for Account 353.01 is most appropriate. We note for Account 353.01, the Presiding Judge has considered the methodology used by PG&E, and further considered the historical values analyzed by Trial Staff in which outlier transactions have been removed, as informed by the NARUC Manual. Further, the Presiding Judge has considered the net salvage ratios for similarly situated utilities SoCal Edison and SDG&E, and finds the proposed net salvage value for this account in line with those values.³¹⁵ Finally, we find that the Presiding Judge gave reasoned consideration to the methodologies proposed by TANC and Trial Staff, and reasonably rejected those proposals for the reasons identified above, and therefore we reject the arguments raised by TANC and Trial Staff in their briefs on exceptions to the Initial Decision.

ii. Account 354, Towers & Fixtures

131. For Account 354, Towers and Fixtures, the Presiding Judge concluded that PG&E's proposed net salvage of (100) for this account was most appropriate. He reasoned that PG&E's recommendation was based on historical data showing that PG&E's net salvage ratio averaged (145) over 20 years. The Presiding Judge also notes PG&E's proposed net salvage value for this account was in line with SDG&E's and

³¹⁴ Initial Decision, 165 FERC ¶ 63,001 at PP 519-525.

³¹⁵ The Presiding Judge relied on the net salvage ratios available in the record for SoCal Edison and SDG&E. See Ex. S-0005.

SoCal Edison's ratios of (100) and (70), respectively, for this account. Further, he reasoned that (100) is less negative than PG&E's historical 20-year average ratio of (145) and lower than Trial Staff's calculation of an average ratio (based on PG&E's historical data) with outliers removed, (112).³¹⁶

132. The Presiding Judge examined and declined to accept Trial Staff's recommendation of (39), which is based on an industry average of (34) adjusted downward to give some recognition to the historical data and TANC's proposed net salvage value based on the threshold for the most negative quintile among his companies (41). The Presiding Judge reasoned that the industry statistics upon which Trial Staff and TANC witnesses rely provided little support for their positions observing that none of the companies in TANC's survey are similarly situated to PG&E, and that they should have focused on SoCal Edison and SDG&E.³¹⁷

133. We affirm the Initial Decision on this issue, and find that PG&E's proposed net salvage ratio of (100) for Account 354 is most appropriate. Similar to his analysis for Account 353.01, the Presiding Judge has considered the methodology used by PG&E, and further considered the historical values analyzed by Trial Staff in which outlier transactions have been removed, as informed by the NARUC Manual. Further, the Presiding Judge has considered net salvage ratios for similarly situated utilities, i.e., SoCal Edison and SDG&E, and finds the proposed net salvage value for this account in line with those values. We find the Presiding Judge's analysis, and his consideration and rejection of other proposed approaches, to be reasonable, and, nothing in the briefs on exceptions to the Initial Decision persuade us otherwise. Accordingly, we affirm his decision.

iii. Account 355, Poles & Fixtures

134. For Account 355, Poles and Fixtures, the Presiding Judge concluded that PG&E's proposed net salvage of (80) for this account was most appropriate. He reasoned that PG&E's recommendation was based on historical data for this account showing that PG&E's net salvage ratio averaged (148) over 20 years. The Presiding Judge also noted that PG&E's proposed net salvage value for this account was supported by SDG&E's net salvage value of (100) for this account as reflected in its 2014 FERC Form 1, and a 2003 proposed SoCal Edison ratio of (115).³¹⁸ Trial Staff's analysis resulted in a historical ratio of (69) with outliers removed. The Presiding Judge found Trial Staff's removal of outliers from the historical data for this account unsupported, and thereby rejected those

³¹⁶ Initial Decision, 165 FERC ¶ 63,001 at PP 530-536.

³¹⁷ *Id.* PP 533-535.

³¹⁸ Initial Decision, 165 FERC ¶ 63,001 at PP 537-544.

adjustments, noting that if PG&E experiences an atypical ratio in one 20-year period, it will likely experience another atypical ratio in the subsequent 20-year period.³¹⁹

135. We overturn the Presiding Judge's determination in the Initial Decision, which authorized PG&E's proposed net salvage value of (80) for Account 355. First, we find that PG&E has not justified its proposal. PG&E's proposed ratio of (80) is significantly less than the average calculated by PG&E using its historical data, (148). This indicates that PG&E finds that its historical data needed significant adjustment. We find that Trial Staff's analysis of the PG&E's historical data, in which it removed outliers, is consistent with the NARUC Manual, which states that transactions considered to be unrepresentative of the future should be removed from the historical data.³²⁰ Therefore, we find that the Presiding Judge erred in dismissing Trial Staff's adjustment to remove outliers from the historical data. Trial Staff's analysis also aligns with a more recent net salvage ratio for a California investor-owned utility than what the Presiding Judge relied on in authorizing PG&E's proposal. Specifically, the Presiding Judge compared PG&E's proposed ratio of (80) to a ratio proposed by SoCal Edison in 2003. However, we find a more recent net salvage ratio available in SoCal Edison's 2014 Form 1 data, which is (70) for this account.³²¹ For these reasons, we overturn the Presiding Judge and authorize a net salvage ratio of (69), consistent with Trial Staff's analysis.

iv. Account 356, Overhead Conductors & Devices

136. For Account 356, Overhead Conductors & Devices, the Presiding Judge concluded that PG&E's proposed net salvage of (110) for this account was most appropriate. He reasoned that P&E's recommendation was based on historical data showing that PG&E's net salvage ratio averaged (129) over 20 years. The Presiding Judge also notes PG&E's proposed net salvage value for this account was in line with SoCal Edison's and SDG&E's ratios of (80) and (100), respectively. He further reasoned that (110) is less negative than PG&E's historical 20-year average ratio of (129) and lower than Trial Staff's calculation of an average ratio based on PG&E's historical data with outliers removed, (119).³²²

137. The Presiding Judge examined and declined to accept Trial Staff's recommendation of (45), which is based on an industry group average of (40) adjusted downward to give some recognition to the historical data and TANC's proposed net

³¹⁹ *Id.* PP 542-544.

³²⁰ NARUC Manual at 158.

³²¹ Ex. S-0005 at 7.

³²² Initial Decision, 165 FERC ¶ 63,001 at PP 545-550.

salvage value based on the threshold for the most negative quartile among identified companies (50). The Presiding Judge notes that TANC'S witness previously submitted a value of (125) for distribution overhead conductors in a state proceeding. He notes that the historical data that PG&E's witness uses appears reliable.³²³

138. We affirm Initial Decision on this issue, and find that PG&E's proposed net salvage ratio of (110) for Account 356 is most appropriate. We note that for Account 356, the Presiding Judge has considered the methodology used by PG&E and has further considered the historical values analyzed by Trial Staff in which outliers have been removed, as recommended by the NARUC Manual. Further, the Presiding Judge has considered the net salvage ratios available for SoCal Edison and SDG&E as similarly situated utilities, and found the proposed net salvage value for this account in line with those values. As with Accounts 353.01 and 354, we find that the Presiding Judge's analysis was reasonable and in accordance with the NARUC Manual's recommendations for calculating net salvage, and we therefore reject the arguments raised by TANC and Trial Staff in their briefs on exceptions to the Initial Decision.

v. Account 358, Underground Conductors & Devices

139. For Account 358, Underground Conductors & Devices, PG&E requested a ratio of (10). The Presiding Judge noted that TANC proposed a ratio of (6) and Trial Staff proposed a ratio of (14). He also noted that during the period, 1996-2015, PG&E's average net salvage ratio for this account was (71). The Presiding Judge observed that Trial Staff's witness based his recommended ratio of (14) on the average of his utility group (9), adjusted to give consideration to the historical data. He also noted that the witness expressed concern about the years that show a recovery of costs, but reflect no retirements, but in so doing did not reject of PG&E's historical data entirely.

140. The Presiding Judge concluded that Trial Staff's proposed net salvage ratio of (14) was best suited to the account, basing his finding on Trial Staff's methodology, which considers industry statistics yielding an industry average of (9) with a downward adjustment to (14) to give some recognition to the historical data. He reasoned that the ratio is midway between the ratios of the two entities in Trial Staff's industry group that are similarly situated to PG&E, SoCal Edison,(20), and SDG&E,(10).³²⁴ The Presiding Judge explained that Trial Staff's decision to give some consideration to the historical data appears warranted and stated that the 20-year period over which PG&E's ratio has

³²³ *Id.* P 546.

³²⁴ *Id.* P 556 (citing Ex. S-0005 at 11).

been averaged would appear to smooth out the distortions resulting from the years in which removal costs without retirements have been recorded.³²⁵

141. We note the Presiding Judge approved a ratio lower than that which PG&E proposes. Further, we observe the Presiding Judge deviated from the methodology he used to analyze other net salvage accounts where he relied upon PG&E's historical data as reflective of PG&E's historical experience, and instead based his finding on Trial Staff's approach. Trial Staff's witness calculated an industry average for each account based on authorized and proposed net salvage ratios from 22 companies. Trial Staff takes the historical data into consideration as well as the high removal costs in California and applies a (5) adjustment to the industry average net salvage ratios. While the industry average likely warrants adjustment to apply to California, a (5) adjustment appears unsupported and to be lacking sufficient justification for its application to the industry data.

142. We also note PG&E proposed its currently authorized value, (10)%, which indicates the company believes this value is sufficient to recover net salvage costs for this account. We further note a net salvage ratio of (10) for this account is within the zones supported by Trial Staff's analysis, i.e., 0 to (40), and TANC's analysis, i.e., 0 to (35). This value, while less than SoCal Edison's net salvage value for the same account, is equal to the value in the record for SDG&E. Accordingly, we find that PG&E has supported its proposed value. We therefore reverse the Initial Decision and find that PG&E's proposed value of (10) for Account 358 is more appropriate for this account.

vi. Account 359, Roads & Trails

143. For Account 359, Roads & Trails, the Presiding Judge concluded that PG&E's proposed net salvage of (10) for this account was most appropriate. He reasoned that P&E's recommendation was based on historical data showing that PG&E's net salvage ratio for the period 1996-2015 averaged (40) with outliers, and lower than Trial Staff's calculation of an average ratio (based on PG&E's historical data) with outliers removed, (20). The Presiding Judge stated that the 20-year average is more significant than the

³²⁵ During two of the years PG&E recorded removal costs without retirements, 1996 and 2001, the removal costs recorded were \$35 and \$340. During two of the intervening years, 1997 and 2000, PG&E recorded \$22,805 in retirements without any removal costs. During the period 2001-2008, PG&E recorded removal costs without retirements during five years, 2001-2003 and 2005-2006, and negligible retirement costs the other two years. However, due to retirements totaling \$2,163,418 in 2008, retirements for the eight-year period totaled \$2,169,282, whereas removal costs totaled \$1,538,867. PG&E's average net salvage ratio for the period was (71), the same as the 20-year average. *Id.* P 556 n. 634 (citing Ex. PGE-0029 at 106).

most recent five-year average (supported by TANC) and resolves distortions and anomalies in individual years.

144. The Presiding Judge examined and declined to accept Trial Staff's recommendation of (6), which was calculated based upon utilities in an industry group, and adjusted downward to give some recognition to the historical data, and TANC's proposed net salvage value of zero (0) based on an analysis that considers the prior five year period where no removal costs were incurred for this account.

145. We affirm the Initial Decision on this issue, and find that PG&E's proposed net salvage ratio of (10) for Account 359 is most appropriate. The NARUC Manual states that transactions considered to be unrepresentative of the future should be removed from the historic data.³²⁶ We note for Account 359, the Presiding Judge has considered the methodology used by PG&E, and further considered the historical values analyzed by Trial Staff in which outlier transactions have been removed, as advised by the NARUC Manual.

E. Capital Additions

146. PG&E developed its forecasted Period II weighted average balance for gross plant in service (i.e., PG&E's rate base) in two steps. First, PG&E has added and subtracted the forecasted 2016 plant additions and retirements, respectively, from the Period I end-of-year gross plant to arrive at a forecasted Period II beginning gross plant balance. Second, PG&E has added and subtracted, respectively, the forecasted monthly 2017 plant additions and retirements from the forecasted Period II beginning gross plant balance to arrive at twelve month-end balances. The weighted average gross plant balance for Period II is an average based on these thirteen balances.³²⁷

1. Capital Additions Forecast

a. Initial Decision

147. In examining PG&E's proposal, the Presiding Judge stated that the D.C. Circuit has set out criteria for assessing the justness and reasonableness of a utility's forecasts. Under the D.C. Circuit's opinion in *Villages of Chatham & Riverton v. FERC*,³²⁸ "[t]he utility must demonstrate that its estimates were reasonable when made, either by

³²⁶ NARUC Manual at 158.

³²⁷ Initial Decision, 165 FERC ¶ 63,001 at P 592 (citing Ex. PGE-0010 (Testimony of Beatrix H. Greenwell) at 28:16-23).

³²⁸ 662 F.2d 23 (D.C. Cir. 1981) (*Chatham*).

explaining the chain of reasoning that is employed to arrive at its projections, or by comparing its estimates with actual data, and so establishing their accuracy.”³²⁹ Thus, the Presiding Judge stated that the reasonableness of PG&E’s forecast turns on either: (1) the chain of reasoning PG&E used to determine an accurate in-service date; or (2) PG&E’s track record in accurately forecasting such dates. Finding scant information in the initial and reply briefs, the Presiding Judge observed that PG&E provided no explanation of how it ensures in-service dates are accurate. Moreover, the Presiding Judge was not persuaded by PG&E’s explanation of the utility’s procedures, and concluded that PG&E did not establish a coherent method for reasonably forecasting its operative dates and capital additions.³³⁰ Therefore, the Presiding Judge found that PG&E failed prong 1 of the *Chatham* test that requires to demonstrate that its estimates were reasonable when made by explaining the chain of reasoning that is employed to arrive at its projections.³³¹

148. Further, the Presiding Judge found that PG&E failed the second prong of the *Chatham* test, which evaluates the variance between the company’s forecasted and actual capital additions, because PG&E has a history of over-forecasting its capital additions by an average of 4.95%.³³² The Presiding Judge noted that PG&E asserted that CPUC’s testimony showed that PG&E’s actual capital additions exceeded the forecasts for 2006, 2009, 2010, 2013, and 2014, but found those figures to be misleading.³³³ The Presiding Judge instead relied on Six Cities’ testimony comparing forecasts and actual capital additions for seven consecutive years from 2007-2015, showing that PG&E’s has over-forecast during this seven-year period by 4.95%.³³⁴

149. Next, the Presiding Judge considered two proposed reductions to PG&E’s proposal based on PG&E’s past over-projections of capital additions and consequent

³²⁹ Initial Decision, 165 FERC ¶ 63,001 at P 595 (citing *Chatham* 662 F.2d at 29).

³³⁰ *Id.* PP 589, 597-600, 602, 607 (citing Ex. PGE-0043, Rebuttal Testimony of Bangalore Vijayraghavan).

³³¹ *Id.* P 607.

³³² *Id.* PP 608-609 (citing Ex. CIT-0045 (Six Cities Analysis of PG&E Projected Capital Additions vs. Actual Capital Additions) at 1).

³³³ *Id.* P 610 & n.692 (citing PG&E Initial Br. at 44 (citing Ex. PUC-0001 (Testimony of Geneva Looker); Tr. at 1925:9-1928:10 (Looker))).

³³⁴ *Id.* P 609 & n.691 (citing Ex. CIT-0045 at 1).

over-recoveries but declined to use them.³³⁵ The Presiding Judge reasoned that to continue to factor PG&E's past over-forecasts in determining its cost of service, regardless of the merits of the its current forecast, would amount to imposing a formula-rate regime on PG&E, when PG&E has exercised its right to use stated rates. Instead, the Presiding Judge chose to focus on PG&E's failure to properly forecast the operative dates of its capital additions for 2017.³³⁶ The Presiding Judge explained that capital expenditures go into the utility's rate base until the facility goes into service, and properly forecasting the service date is thus key to an accurate forecast.³³⁷ As the Presiding Judge explained, how much a capital addition adds to rate base in a given year turns not only on the size of the addition but also when it is added to rate base. The Presiding Judge noted that, because the calculation of rate-base size for the year is based on a thirteen-month average rather than on the end-of-year balance, a project that goes into rate base during January of the year adds 12/13 of its value to rate base, whereas a project that goes into rate base during December of the year adds only 1/13 of its value.³³⁸ The Presiding Judge found that the evidence painted a picture "of a company that projects operative dates with little regard for contingencies that might postpone them."³³⁹ Therefore, the Presiding Judge concluded that PG&E must remove \$76.839 million from its rate base to make its capital additions just and reasonable.³⁴⁰

b. Briefs on Exceptions

150. PG&E claims that the Initial Decision's conclusion that it is better for PG&E to over-forecast does not cite to record evidence and contends that the Initial Decision's finding reveals a strong bias against stated rates versus formula rates.³⁴¹ PG&E also

³³⁵ *Id.* PP 618-619 (citing Ex. CIT-0046 (Six Cities Analysis of Impact of Reducing PG&E's Capital Additions) and Ex. S-0023 (Testimony of Joseph R. Hoffman) at 10-16-12:12).

³³⁶ *Id.* P 620.

³³⁷ *Id.* P 593.

³³⁸ *Id.* P 611 (citing Ex. PGE-0010 at 28:20-23).

³³⁹ *Id.* PP 614- 615 (citing Ex. TNC-0018 (Testimony of David Cohen) at 19:10-20:5, Ex. PGE-0043 at 5:1-12, Ex. TNC-0183 at 4, and Tr. 1175:23-1177:1 (Vijayraghavan)).

³⁴⁰ *Id.* P 621; *see also id.* P 617 (citing *NEPCO Mun. Rate Comm. v. FERC*, 668 F.2d 1327, 1340 (D.C. Cir. 1981) (*NEPCO*)).

³⁴¹ PG&E Brief on Exceptions at 56.

contends that it properly justified its capital additions forecast.³⁴² In support, PG&E points to three witnesses that explained the forecast process, and asserts the Initial Decision erred in presuming their claims lacked credibility. PG&E argues that the Presiding Judge ignored its witness' testimony that PG&E's performance has recently improved and misinterpreted testimony that was presented to describe the capital expenditures PG&E was forecasting it would make.³⁴³ Regardless, PG&E contends that even if it did not make the required chain of reasoning showing, the final capital additions for 2016 were very close to the amount projected in 2017.³⁴⁴

151. Further, PG&E argues that it is impossible to give a precise forecast of when each project will be operational.³⁴⁵ PG&E contends that the Initial Decision erroneously relied on one data response to reach its conclusion,³⁴⁶ and disputes the Initial Decision's methodology that requires the utility to update its filed forecast to one made 18 months later.³⁴⁷ PG&E disagrees with the Initial Decision's finding that it failed the *Chatham* test because, in contrast to the circumstances there, PG&E did not base its forecast on absurd estimates or lack of information explaining the estimates. PG&E argues that its forecast was reasonable when made.³⁴⁸

152. CPUC states that the Initial Decision properly found that PG&E's capital additions forecast was not just and reasonable. CPUC argues that the Presiding Judge's decision to disallow \$77.839 million from PG&E's rate base, resulting in a TRR reduction of roughly \$12 million, is based on a well-reasoned review of the substantial evidence in the case, including an analysis showing PG&E's conclusory and inconsistent testimony.³⁴⁹

153. TANC contends that the Initial Decision failed to consider additional evidence on the record when finding that PG&E's capital additions forecast was unjust and

³⁴² *Id.* at 56-57.

³⁴³ *Id.* at 57-58.

³⁴⁴ *Id.* at 59.

³⁴⁵ *Id.* at 60.

³⁴⁶ *Id.*

³⁴⁷ *Id.* at 61.

³⁴⁸ *Id.*

³⁴⁹ CPUC Brief on Exception at 9.

unreasonable.³⁵⁰ First, TANC argues that any project not in the forecast is ineligible for inclusion in the rate base.³⁵¹ Therefore, TANC requests that the Commission disallow this practice.³⁵² TANC further contends that PG&E failed to use mitigating factors within its control that would help it accurately forecast capital expenditures and operative dates.³⁵³ TANC contends that the Initial Decision was correct to find PG&E does not have a coherent method for forecasting, but the Presiding Judge should consider additional evidence that identifies factors PG&E uses to delay its operative dates.³⁵⁴ Accordingly, TANC asks that the Commission consider this additional evidence.³⁵⁵

c. Briefs Opposing Exceptions

154. TANC contends that the Commission should deny PG&E's exceptions to the Initial Decision's finding because PG&E failed both prongs of the *Chatham* test.³⁵⁶ First, TANC contends, PG&E did not prove its capital additions forecast is just and reasonable because its argument to overturn the Initial Decision's findings relies on evidence the Presiding Judge stated was "no more than a litany of generalities."³⁵⁷ Second, TANC argues, PG&E did not prove that its historical data establishes that the capital additions forecast was just and reasonable when made.³⁵⁸ TANC states that the Initial Decision correctly rejected the evidence PG&E cites in its brief because that evidence did not consider the impact of capital additions on rate base.³⁵⁹ TANC contends that it demonstrated that the "Weighted Average Gross Plant in Service" varies depending on

³⁵⁰ TANC Brief on Exceptions at 77.

³⁵¹ *Id.* at 77-78.

³⁵² *Id.* at 78.

³⁵³ *Id.* at 77, 79 (citing Ex. TNC-0018 at 13:13-17:19 (identifying errors in PG&E's methodology for forecasting operative dates)).

³⁵⁴ *Id.* at 79.

³⁵⁵ *Id.* at 80.

³⁵⁶ TANC Brief Opposing Exceptions at 69.

³⁵⁷ *Id.* at 71-72.

³⁵⁸ *Id.* at 73.

³⁵⁹ *Id.* (citing Initial Decision, 165 FERC ¶ 63,001 at P 613).

the month during the test year the project becomes operational,³⁶⁰ and notes that PG&E's witness agreed with TANC's argument.³⁶¹

155. Six Cities contends that the Initial Decision's adjustment of PG&E's proposed capital additions was correct.³⁶² Six Cities agrees with the Initial Decision's finding that PG&E failed to establish "through a chain or reasoning or otherwise" that its proposed capital additions passed the *Chatham* test.³⁶³ Six Cities argues that PG&E ignores the discrepancy between its forecasted and actual capital additions.³⁶⁴ Six Cities claims the Initial Decision correctly relied on its witness' conclusion that PG&E historically over-forecasts its capital additions by approximately 4.59% annually.³⁶⁵ Six Cities also contends that the Initial Decision correctly denied as inconsistent and lacking credibility, PG&E's explanation for its over-forecasting methodology.³⁶⁶ According to Six Cities, PG&E's witness' argument against the suggested adjustment to its forecasted capital additions is that PG&E implemented several project management initiatives that are sufficient to satisfy the *Chatham* "chain of reasoning" prong.³⁶⁷ Six Cities argues that these initiatives do not satisfy the test because there is no sufficient evidence to show a relationship between the initiatives and PG&E's capital additions forecast.³⁶⁸ Six Cities further asserts that there is no evidence that these initiatives affect PG&E's ability to

³⁶⁰ *Id.* at 74.

³⁶¹ *Id.*

³⁶² Six Cities Brief Opposing Exceptions at 44.

³⁶³ *Id.* at 45.

³⁶⁴ *Id.* (citing *Chatham* 662 F.2d at 29 ("[d]isregarding disparities . . . is not consistent with the statutory allocation of the burden of proof to the utility," and that one way a utility can justify its cost estimates is to "demonstrate the congruence of its projections with actual results"))).

³⁶⁵ *Id.* at 46 (citing Ex. CIT-0045 at 1-10; Initial Decision, 165 FERC ¶ 63,001 at PP 611-613 (noting that it is appropriate to assess forecast accuracy on a weighted average basis and observing that Six Cities' witness' analysis reflects a weighted average)).

³⁶⁶ *Id.* at 48 (citing Initial Decision, 165 FERC ¶ 63,001 at PP 603-605).

³⁶⁷ *Id.* at 49.

³⁶⁸ *Id.* at 51.

meet its forecasted capital additions.³⁶⁹ Trial Staff supports the Presiding Judge's finding that PG&E's proposed capital additions forecast is unjust and unreasonable, as well as his reasoning in reaching this decision.³⁷⁰

156. PG&E contends that the D.C. Circuit's decision in *Cities of Anaheim, Riverside, Banning, Colton, & Azusa v. FERC*³⁷¹ correctly states that the Commission should not reject a test year forecast merely because it varies from the actual results.³⁷² PG&E contends that it made a reasonable test year forecast and the actual results, in terms of overall capital additions in the test year were very close to the forecast, noting that the mix of projects differed from that reflected in the forecast to the test year, and the operational dates differed from the test year.³⁷³

d. Commission Determination

157. We affirm the Presiding Judge's finding that PG&E's capital additions forecast will not produce just and reasonable rates. We disagree with PG&E's assertion that the Presiding Judge rejected the forecast merely because it varies from actual results. To make the determination on the justness and reasonableness of PG&E's proposal, the Presiding Judge correctly applied the two-prong *Chatham* test to evaluate PG&E's proposed capital additions forecast and concluded that PG&E failed both prongs. The record shows that the Presiding Judge, consistent with *Chatham*, carefully examined the chain of reasoning employed by PG&E to arrive at its proposed forecast and concluded that PG&E failed it because it provided no evidence (other than conclusory statements) describing procedures for assuring the accuracy of PG&E's forecasts, including the forecasted in-service dates.³⁷⁴ We agree that PG&E failed to support its proposed forecasts of capital additions.

158. We also disagree with PG&E's allegation that the Presiding Judge ignored the evidence it presented to show that its performance has recently improved. The Initial Decision fully addressed this issue in paragraph 613. Specifically, the Presiding Judge

³⁶⁹ *Id.*

³⁷⁰ Trial Staff Brief Opposing Exceptions at 27-29.

³⁷¹ 669 F.2d 799, 804 (D.C. Cir. 1981) (*Anaheim*).

³⁷² PG&E Brief Opposing Exceptions at 56 (citing Initial Decision, 165 FERC ¶ 63,001 at PP 489-586).

³⁷³ *Id.*

³⁷⁴ Initial Decision, 165 FERC ¶ 63,001 at PP 597-607.

reasoned that net capital additions, i.e., additions minus retirements, are what impact the rate base, not gross capital additions.³⁷⁵ We are also not persuaded that the Presiding Judge should have considered the witness testimony only for the narrow purpose it was presented. The Presiding Judge drew conclusions based on relevant data and calculations submitted into the record. In this case, we defer to the Presiding Judge's judgment as to which evidence was relevant to which issue.³⁷⁶ We also note that with regard to the credibility of witnesses, and the amount of weight to be accorded to particular testimony or evidence, the Presiding Judge was the trier of fact, had the opportunity to observe the witnesses' live testimony and demeanor, and was thus in the best position to evaluate the witnesses' credibility.³⁷⁷ PG&E has provided us with no reason to question the Presiding Judge's observations in this regard.

159. In addition, consistent with the second prong of the *Chatham* test, the Presiding Judge considered the discrepancies between prior forecasts performed by PG&E and actual data for previous years and concluded that there is a pattern of over-forecasting and not considering various contingencies in regard to projected in-service dates.³⁷⁸ We agree with the Presiding Judge's observation that there would be little incentive not to include its over-forecasts in in-service dates, and that the persistent forecasting problems documented in the record results in a capital additions forecast that is not just and reasonable.³⁷⁹ In reaching these conclusions, the Presiding Judge considered record evidence showing the persistent inaccuracies in PG&E's forecasting of in-service dates to be the decisive factor and on this basis found that PG&E must remove \$76.839 million from its rate base.³⁸⁰ Neither PG&E nor any other party has offered an alternative

³⁷⁵ *Id.* P 613.

³⁷⁶ See, e.g., *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, Opinion No. 536, 149 FERC ¶ 61,116, at P 193 (2014).

³⁷⁷ See, e.g., *Inwood Lab. Inc. v. Ives Lab., Inc.*, 456 U.S. 844, 856 (1982) (holding that "determining the weight and credibility of the evidence is the special province of the trier of fact."); *El Paso Nat. Gas Co.*, 67 FERC ¶ 61,327, at 62,156 (1994) (finding that "[i]n matters where a decision had to be made as to the relative weight to be accorded the testimony of a witness, we will give great deference to the decision of the ALJ"); *Williams Nat. Gas Co.*, 41 FERC ¶ 61,037, at 61,095 (1987) (finding that "the rationale for affording deference to the determinations of the trier of fact on credibility is that the trier of fact is in the best position to evaluate such elusive factors as motive or intent").

³⁷⁸ Initial Decision, 165 FERC ¶ 63,001 at PP 613-619.

³⁷⁹ *Id.* P 615.

³⁸⁰ *Id.* PP 593, 611, 614-615.

reduction. We find that the Presiding Judge made a reasoned decision supported by record evidence.³⁸¹ We therefore affirm the Presiding Judge's finding and direct PG&E to remove \$76.839 million from its rate base.

2. Inclusion of Allegedly Imprudent Capital Costs

160. PG&E proposed that its TO18 TRR should include \$288.3 million in capital expenditures for a 3.5-mile 230 kV cable between the Embarcadero and Potrero Substations (Embarcadero-Potrero Project). According to PG&E, it developed the Embarcadero-Potrero Project to provide additional transmission capacity to the San Francisco 115 kV transmission cable system to allow for the shutdown of the Potrero power plant, as well as to provide an additional power source into the Embarcadero substation to improve service reliability to downtown San Francisco.³⁸² PG&E also proposed that its TO18 TRR should include approximately \$750 million for other projects.³⁸³

a. Initial Decision

161. First, the Presiding Judge addressed CPUC's assertion that PG&E's capital additions include imprudent capital costs.³⁸⁴ To analyze this assertion, the Presiding Judge relied on the standard of review set in *BP Pipelines (Alaska) Inc.*³⁸⁵ The Presiding Judge explained that under *BP Pipelines* "[t]o determine the prudence of an investment, the Commission evaluates whether a reasonable utility manager would have made the same investment under the same circumstances," and that a prudent determination is based upon what the utility knew the time it made the decision.³⁸⁶ Additionally, the

³⁸¹ We also disagree with PG&E's unsupported claim that the Presiding Judge's decision reveals a bias against stated rates as opposed to formula rates. The Presiding Judge found, correctly, that PG&E's forecasting was not just and reasonable due to persistent flaws in its forecasting, as discussed herein.

³⁸² See Ex. PGE-0009 (Testimony of PG&E Witness) at 17-18.

³⁸³ PG&E's other transmission projects are described in more detail in Ex. PGE-0009 at 19-64.

³⁸⁴ Initial Decision, 165 FERC ¶ 63,001 at P 622.

³⁸⁵ *Id.* P 623 (citing *BP Pipelines (Alaska) Inc.*, 153 FERC ¶ 61,233, at P 13 (2015) (*BP Pipelines*)).

³⁸⁶ *Id.*

Presiding Judge noted, there is a presumption of prudence until a challenging party creates serious doubt and the utility has the burden of dismissing those doubts.³⁸⁷

162. Next, the Presiding Judge considered CPUC's request to disallow \$73 million from PG&E's TRR to address the company's allegedly unjust and unreasonable practice of "self-approving" more than 60% of its capital additions finding this contention outside the scope of the current proceeding. The Presiding Judge reasoned that "simply showing that PG&E often bypasses CAISO when making capital additions is not evidence that the additions are unjust and unreasonable."³⁸⁸

163. Further, the Presiding Judge considered CPUC's contention that PG&E's expenditures on the Embarcadero-Potrero Project's cable exceeded just and reasonable costs by \$91.3 million.³⁸⁹ The Presiding Judge explained that PG&E filed for a Certificate of Public Convenience and Necessity (CPCN) with CPUC for the Embarcadero-Potrero Project with a final forecasted cost of \$196.8 million, while the forecast of the final cost of the Embarcadero-Potrero Project proposed by PG&E in this proceeding is \$288.3 million, which is \$91.3 million more than the forecast initially presented to and approved by CPUC.³⁹⁰

164. The Presiding Judge rejected CPUC's assertion that *Anaheim* applies and declined to defer to CPUC.³⁹¹ The Presiding Judge was not persuaded that, pursuant to *Anaheim*, CPUC's disallowance of capital costs incurred by PG&E was sufficient to rebut the presumption of prudence and shift the burden to PG&E to establish prudence of its expenders. The Presiding Judge reasoned that CPUC's characterization of \$196.8 million as the project's "maximum reasonable cost" is not equivalent to a determination that all costs in excess of the amount should be disallowed. In the Presiding Judge's view, CPUC's determination on capital costs in the CPCN proceeding was simply an adoption of PG&E's assessment, made prior to commencement of construction, as to what the

³⁸⁷ *Id.*

³⁸⁸ *Id.* PP 622, 625.

³⁸⁹ *Id.* PP 622, 627.

³⁹⁰ *Id.* PP 628, 632 (citing Ex. PUC-0001 at 28:27-29:1).

³⁹¹ *Id.* PP 634-635 (citing *Anaheim*, 669 F.2d at 799). The Presiding Judge explained that in *Anaheim*, the D.C. Circuit affirmed a Commission decision that "state disallowance of a cost incurred by a utility was sufficient to rebut the presumption of prudence and shift the burden to the utility to establish prudence of its expenditures." *Id.* P 635.

maximum cost of the project should be.³⁹² The Presiding Judge found that CPUC's claim that the final expense was above the amount PG&E told CPUC the Project would cost is not equivalent to a determination that all costs above this amount were imprudent and should be disallowed.³⁹³ The Presiding Judge was also not persuaded by the evidence presented by CPUC, specifically, three pages from a January 2015 report describing an internal audit that PG&E conducted to improve the efficiency of operations. The Presiding Judge concluded that the size, cost, and complexity of the Project meant some mistakes are inevitable but they do not constitute mismanagement³⁹⁴ or raise doubts to the prudence of the expenditures.³⁹⁵ The Presiding Judge also found CPUC's assertion of other issues including "whether PG&E's procedures related to capital additions, such as planning and prioritization, recordkeeping, cost estimating, and project cost containment are appropriate," did not warrant consideration as separate issue from the issue of alleged imprudent capital costs.³⁹⁶

b. Briefs on Exceptions

165. CPUC objects to the Initial Decision's conclusions on PG&E's "self-approved" transmission projects and the Embarcadero-Potrero Project. With respect to "self-approved" projects, CPUC first contends that the issue is within the scope of this case, and that the Presiding Judge erred in deciding otherwise.³⁹⁷ CPUC argues that the evidence it presents "demonstrates that PG&E's ad hoc practices to identify and pursue capital additions projects ensure that its rates cannot be just and reasonable because the practices result in capital additions that cannot be shown to be needed or cost effective."³⁹⁸ Accordingly, CPUC contends that the Presiding Judge's decision would leave the parties with no recourse to address these practices.³⁹⁹ CPUC also contends that

³⁹² *Id.* P 636.

³⁹³ *Id.* PP 634, 636.

³⁹⁴ *Id.* PP 641-43 (citing Ex. PUC-0018 (Jan. 2017 and Apr. 2013 CPUC Audit Reports)).

³⁹⁵ *Id.* P 644.

³⁹⁶ *Id.* P 651.

³⁹⁷ CPUC Brief on Exceptions at 10.

³⁹⁸ *Id.* at 10-11 (*emphasis omitted*).

³⁹⁹ *Id.* at 12.

the Initial Decision should have considered evidence that these practices are unjust and unreasonable.⁴⁰⁰

166. CPUC argues that PG&E must prove the scale of its self-approved projects and advancement practices and their impact on rates are “just and reasonable and not unduly discriminatory and preferential.”⁴⁰¹ CPUC identifies a list of PG&E’s self-approved projects to demonstrate the magnitude of this practice and claim that these projects add approximately \$750 million in capital additions to the utility’s rate base.⁴⁰² CPUC also argues that the record shows that PG&E does not have the necessary data or procedures to perform the data-driven, condition-based methodologies it claims it used to identify the capital additions.⁴⁰³ CPUC points to PG&E’s witness’ testimony describing the methodology used and argues that the evidence does not prove PG&E had appropriate procedures in place to comply with the methodology.⁴⁰⁴ Thus, CPUC concludes, PG&E could only apply an *ad hoc* process that relied on inaccurate and incomplete data.⁴⁰⁵

167. CPUC further contends that PG&E’s evidence to support its methodology reflects PG&E’s aspiration to perform data-driven and condition-based methodologies, but it did not apply these methods to the projects at issue.⁴⁰⁶ Additionally, CPUC claims that PG&E’s internal audits from 2012 to 2016 reflect the utility’s absence of records management procedures and lack of compliance with any that may have existed.⁴⁰⁷ CPUC claims that PG&E’s audits acknowledge that these issues could result in

⁴⁰⁰ *Id.* at 13.

⁴⁰¹ *Id.*

⁴⁰² *Id.* at 14-16.

⁴⁰³ *Id.* at 16.

⁴⁰⁴ *Id.* at 18.

⁴⁰⁵ *Id.*

⁴⁰⁶ *Id.* at 20, 23; *see also id.* at 21-23 (listing strategies).

⁴⁰⁷ *Id.* at 24; *see also id.* at 24-32 (list of internal audits). CPUC’s concerns with the audits include: (1) lack of procedures to comply with due dates and corrective work that is inappropriately delayed; (2) insufficient inspection of documents combined with supervisors’ failure to notice key errors within these records; (3) supervisors’ inconsistency adhering to or understanding records requirements; (4) missing or misfiled notifications and project documents; and (4) lack of control and consistency.

inaccurate forecasting of project costs.⁴⁰⁸ CPUC claims the audits evidence shows that PG&E's records management was so deficient that PG&E could not comply with its own standard.⁴⁰⁹ CPUC acknowledges that PG&E shows a need and desire for sufficient records management but argues that these processes were not in place prior to PG&E incurring the capital additions expenses at issue.⁴¹⁰

168. CPUC argues that PG&E's witness cross-examination testimony regarding project-by-project prioritization procedures is inconsistent with PG&E's claim of using data-driven, condition-based methodologies to prioritize projects.⁴¹¹ CPUC claims that PG&E's witness testimony in conjunction with the record shows that PG&E's procedures were limited, so its project-by-project analysis to rank transmission lines most in need of replacement relied on *ad hoc* procedures.⁴¹² CPUC contends that PG&E's ranking procedures are inadequate because of missing and inaccurate data and, therefore, the project prioritization procedure is not just and reasonable.⁴¹³

169. CPUC also argues that PG&E's Risk Informed Budget Allocation (RIBA) process, which uses a scoring system to identify and prioritize capital additions for transmission projects, is deficient because it does not establish a score until a transmission project is in the development phase.⁴¹⁴ CPUC contends that PG&E only identifies a RIBA score after it identifies and prioritizes a project as a part of its planning process to develop detailed budgets and work plans for the entire utility.⁴¹⁵ Next, CPUC contends that PG&E's

⁴⁰⁸ *Id.* at 31.

⁴⁰⁹ *Id.* at 32-33.

⁴¹⁰ *Id.* at 34.

⁴¹¹ *Id.* at 36.

⁴¹² *Id.* at 37.

⁴¹³ *Id.* at 39.

⁴¹⁴ *Id.* at 40 (citing PG&E Brief at 47 (representing that the RIBA process and other considerations “determine the ranking of which projects should have priority. Only after the projects were identified and ranked was a budget for the year applied to determine how much would be available for the Test Year”)).

⁴¹⁵ *Id.* at 41 (citing Ex. PGE-0037 (Rebuttal Testimony of Kevin Dasso) at 16:4-7 (RIBA ensures that projects having the greatest impact on the system safety and reliability are included in the portfolio of work put forth by the core operating Lines of Business)).

project advancement practices are not just and reasonable.⁴¹⁶ CPUC states that “[a]dvanced projects are capital addition projects that PG&E does not include in its capital additions forecast, but which are substituted for forecasted capital additions when those forecasted projects are delayed.”⁴¹⁷ According to CPUC, the Initial Decision acknowledges that this practice is dubious. CPUC contends it is unjust and unreasonable because PG&E does not notify parties that the projects are in rate base.⁴¹⁸

170. CPUC claims that the evidence demonstrates that PG&E’s self-approval and project advancement practices are not just and reasonable.⁴¹⁹ Therefore, CPUC contends that the Commission should remedy this issue by disallowing \$284.4 million (i.e., 25% of the costs of PG&E’s self-approved projects) from PG&E’s forecasted capital additions.⁴²⁰

171. Further, CPUC contends that the Initial Decision was incorrect when it found that the evidence did not show serious doubt about the prudence of PG&E’s cost overruns on the Embarcadero-Potrero Project.⁴²¹ CPUC agrees with the Commission’s holding in *BP Pipeline* “that a utility’s FERC-jurisdictional expenditures are presumed to be prudent, and that a party must provide more than a ‘bare allegation of imprudent’ to rebut this presumption, specifically, there must be ‘serious doubt’ about the prudence of an expenditure.”⁴²² However, CPUC contends that the Initial Decision failed to recognize that the record establishes serious doubt regarding PG&E’s expenditures.⁴²³ CPUC argues that the Initial Decision’s reliance on PG&E’s informal communication with CPUC and its decision not to enforce cost caps against the utility shifts the statutory

⁴¹⁶ *Id.* at 42.

⁴¹⁷ *Id.* (citing Ex. PGE-0043 at 2-8).

⁴¹⁸ *Id.* (citing Ex. PGE-0043 at 5:19-22).

⁴¹⁹ *Id.* at 44.

⁴²⁰ *Id.* at 46.

⁴²¹ *Id.*

⁴²² *Id.* at 47 (citing *BP Pipelines*, 153 FERC ¶ 61,233 at P 13).

⁴²³ *Id.* at 48.

burden of proof from demonstrating serious doubt to actively attempting to stop imprudent expenditures.⁴²⁴ CPUC claims this is unlawful.⁴²⁵

172. CPUC claims that cost overruns and project delays were a foreseeable consequence of PG&E's project mismanagement because the management was not proportionate to the complexity of the projects.⁴²⁶ CPUC argues that the Initial Decision should have recognized that PG&E's inability to explain its cost overrun of \$91.5 million and inconsistencies between PG&E's testimony on the Embarcadero-Potrero Project and the issue at bar raises serious doubt about the prudence of the utility's cost overruns.⁴²⁷ According to CPUC, the only reason PG&E provides for the cost overruns is that the estimate of \$196.8 million was premature and the contingency was too low.⁴²⁸ CPUC states that PG&E's witness testimony fails to identify any specific reason that the cost overruns are inconsistent with PG&E's records and what the utility represented to CPUC when it approved the CPCN application.⁴²⁹ CPUC claims that this evidence establishes serious doubt as to the prudence of PG&E's cost overruns.⁴³⁰

173. Additionally, CPUC contends that the record reflects that PG&E has an incentive to underestimate costs of its projects to CPUC, and that PG&E did so here.⁴³¹ CPUC disagrees with the Initial Decision's finding that CPUC's failure to reopen the CPCN proceeding is relevant to analysis of PG&E's prudence.⁴³² CPUC claims that this finding fails to acknowledge PG&E's decision not to have CPUC authorize the Embarcadero-

⁴²⁴ *Id.* at 48-49.

⁴²⁵ *Id.* at 49 (citing *Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, at 62,168-69 (1999), *order on reh'g* (quoting *Minn. Power & Light Co.*, 11 FERC ¶ 61,312 (1980)) (noting that the law provides that the required showing "cannot be so extensive that it in effect reverses the statutory burden of proof"))).

⁴²⁶ *Id.* at 49, 51.

⁴²⁷ *Id.* at 52.

⁴²⁸ *Id.* at 53-54.

⁴²⁹ *Id.* at 56.

⁴³⁰ *Id.*

⁴³¹ *Id.* at 56-57.

⁴³² *Id.* at 57.

Potrero Project's cost overrun is evidence that it imprudently managed the project.⁴³³ CPUC contends that this finding increases the burden to more than a showing of serious doubt.⁴³⁴ CPUC contends that no precedent supports the Initial Decision's finding that ultimately changes the burden of proof.⁴³⁵ CPUC also contends that while it acknowledges that *Anaheim* is distinct because it found certain expenditures were imprudent, the Initial Decision ignores important policy reasons raised in CPUC had raised as to why the Commission should apply the case.⁴³⁶

174. Finally, CPUC contends that its brief is sufficient to raise serious doubt about the prudence of PG&E's cost overruns on the Embarcadero-Potrero Project.⁴³⁷ CPUC claims the burden now lies with PG&E to show its cost overruns were prudent.⁴³⁸ CPUC claims the issue is not whether the project was prudent, but whether PG&E's expenditures were prudent.⁴³⁹ CPUC lists evidence it claims shows serious doubt including the fact that PG&E exceeded maximum reasonable costs, inconsistencies in PG&E's testimony, PG&E's failure to identify the reason for cost overruns, and that PG&E's actions were consistent with the natural incentive to under estimate costs during project approval.⁴⁴⁰ Therefore, CPUC contends that the Commission should shift the burden to PG&E to demonstrate with specific evidence that its costs were prudent.⁴⁴¹

c. Briefs Opposing Exceptions

175. PG&E explains that, in CPUC's pre-filed testimony and at hearing, it argued that PG&E's practice of "self-approval" of certain transmission projects violated

⁴³³ *Id.* at 57-58.

⁴³⁴ *Id.* at 58.

⁴³⁵ *Id.* at 59.

⁴³⁶ *Id.* at 61.

⁴³⁷ *Id.* at 62.

⁴³⁸ *Id.* at 63.

⁴³⁹ *Id.*

⁴⁴⁰ *Id.* at 66.

⁴⁴¹ *Id.* at 66-67.

Order No. 890⁴⁴² because those projects did not go through CAISO's transmission planning process.⁴⁴³ However, PG&E notes that, since that time, the Commission issued an order⁴⁴⁴ denying a complaint by CPUC and others making this claim, and that CPUC therefore has revised its argument here.⁴⁴⁵ PG&E argues that the Commission should reject CPUC's attempt to reframe the self-approval issue, which attempts to show PG&E's advancement practices are unjust and unreasonable.⁴⁴⁶ PG&E also states that it produced volumes of project files that describe the reasons for and scope of each project.⁴⁴⁷ Therefore, PG&E contends that CPUC did not offer sufficient evidence to prove that the projects nor the costs associated with the projects were imprudently included in the capital additions forecast.⁴⁴⁸ Further, PG&E argues that accepting CPUC's argument would harm the Commission's desire to encourage settlements.⁴⁴⁹

176. Further, PG&E disagrees with CPUC's exception that claims PG&E did not identify a majority of projects the utility advanced in its rate case that costs an estimated \$300 million.⁴⁵⁰ PG&E claims that the calculation CPUC used is incorrect and

⁴⁴² *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

⁴⁴³ PG&E Brief Opposing Exceptions at 59.

⁴⁴⁴ *See Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 (2018), *order denying reh'g*, 168 FERC ¶ 61,171 (2019).

⁴⁴⁵ PG&E Brief Opposing Exceptions at 60 (citing Initial Decision, 165 FERC ¶ 63,001 at P 601).

⁴⁴⁶ *Id.* at 60.

⁴⁴⁷ *Id.* at 61 (citing PG&E Reply Brief at 96; Ex. PGE-0038 (Testimony of David Gabbard) at 10:1-10; Ex. PGE-0043 at 7:11-19; Tr. 1497:10-24 (Rebuttal of David Gabbard)).

⁴⁴⁸ *Id.*

⁴⁴⁹ *Id.* at 62.

⁴⁵⁰ *Id.* at 56-57.

unsupported by an analysis on the record.⁴⁵¹ PG&E does not agree with CPUC's claim that it is responsible for demonstrating how CPUC's calculations are wrong.⁴⁵² PG&E rejects CPUC's contention and claims it included approximately 2,200 capital projects in this filing and "[t]he fact that a small subset of forecasted projects did not go operational... is to be expected."⁴⁵³ PG&E contends that no party proved its capital additions were unjust nor unreasonable, so the Commission should authorize a full recovery of the capital additions.⁴⁵⁴

177. With respect to the Embarcadero-Potrero Project, PG&E contends that CPUC's witness did not provide evidence that any expenditures for the Embarcadero-Potrero Project were imprudent.⁴⁵⁵ PG&E also states that the Initial Decision correctly concluded that *Anaheim* did not apply, claiming that *Anaheim* is distinguishable from the issue here because there was no evidence CPUC had considered and disallowed any costs PG&E has incurred in implementing the project as imprudent.⁴⁵⁶ PG&E states that the current case is beyond the scope of *Anaheim* because there is no state commission decision to which this Commission could defer.⁴⁵⁷

178. PG&E contends that TANC's exception shows the utility does a good job managing its capital additions portfolio because only six projects of 2,200 exhibited poor project management.⁴⁵⁸ PG&E states that those six projects only indicate that PG&E could have done a better job with implementation, not that its forecast is unreasonable.⁴⁵⁹ PG&E contends that TANC's exhibits merely demonstrates that PG&E is constantly working to improve its processes and procedures.⁴⁶⁰ Further, PG&E claims that CPUC's

⁴⁵¹ *Id.* at 57.

⁴⁵² *Id.* at 58.

⁴⁵³ *Id.*

⁴⁵⁴ *Id.* at 59.

⁴⁵⁵ *Id.*

⁴⁵⁶ *Id.* at 64.

⁴⁵⁷ *P Id.*

⁴⁵⁸ *Id.* at 65.

⁴⁵⁹ *Id.* at 66.

⁴⁶⁰ *Id.*

Brief on Exceptions incorrectly interprets PG&E's internal audit documents to claim the utility's processes are deficient and unable to produce reasonable capital additions forecasts.⁴⁶¹ PG&E asserts that these internal audits help it identify areas for improvement and provide feedback so the utility can improve over time.⁴⁶²

d. Commission Determination

179. The Commission has long held that “managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers” and that “the appropriate test to be used” in assessing the prudence of costs “is whether they are costs which a reasonable utility management...would have made, in good faith, under the same circumstances, and at the relevant point in time.”⁴⁶³ Even if a decision turns out to be incorrect in hindsight, the Commission's task is to review the prudence of a utility's actions and the costs resulting from the particular circumstances existing either at the time the costs were incurred or when the utility became committed to incur those expenses.⁴⁶⁴ As the Commission has also held, however, a presumption of prudence exists only until the challenging party creates a serious doubt as to the prudence of an expenditure. If this occurs, the regulated entity has the burden of proof to establish prudence.⁴⁶⁵

180. In this case, we find that CPUC has failed to raise serious doubts about the prudence of PG&E's capital expenditures at issue here. As relevant to the Embarcadero-Potrero Project expenditures, which is the only specifically identified transmission project for which CPUC makes a prudence challenge, the Initial Decision has addressed CPUC's arguments in detail in paragraphs 639-649, and we agree with the Presiding Judge's analysis on this issue. Specifically, we agree that, while CPUC raises concerns about the costs of the Embarcadero-Potrero Project, particularly the cost overruns from its initial forecast in the CPCN proceeding, any mistakes made by PG&E in developing this significant transmission project “do not constitute the kind of mismanagement that should raise serious doubts about the prudence of their expenditures.”⁴⁶⁶ On exceptions,

⁴⁶¹ *Id.* at 67.

⁴⁶² *Id.*

⁴⁶³ *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985).

⁴⁶⁴ *Id.*

⁴⁶⁵ *BP Pipelines*, 153 FERC ¶ 61,233 at PP 12-14.

⁴⁶⁶ Initial Decision, 165 FERC ¶ 63,001 at P 644.

CPUC gives us no reason to revisit the Presiding Judge’s analysis, and we find its challenge does not raise serious doubts about the prudence of the costs PG&E incurred.

181. In regard to the issue of PG&E’s “self-approved” projects, CPUC has failed to raise discrete issues and present specific evidence raising doubts pertaining to the prudence of capital costs of a specific transmission project. As the Commission has explained, whether costs were prudently incurred is a fact-specific inquiry and the Commission must examine the prudence of specific costs.⁴⁶⁷ It does not suffice to make general, sweeping allegations of imprudence without focusing on costs incurred with respect to specific transmission projects, as is the case with CPUC’s challenge to the “self-approved” projects. Accordingly, we find that CPUC has not raised serious doubts as to the prudence of costs associated with PG&E’s so-called “self-approved” transmission projects. We therefore affirm the Presiding Judge’s findings on these issues.⁴⁶⁸

F. Allocating Common, General and Intangible (CGI) Plant Costs

182. CGI plant is a category of FERC Account 101 – Electric Plant in Service, which is applicable to the production, transmission, and distribution functions of electric service. Common plant-in-service is plant used by both production and transmission, but cannot be associated with either function directly. General plant-in-service consists of items used for utility purposes which cannot be accounted for elsewhere, such as vehicles, communication equipment, and the company’s central headquarters and office furniture. Intangible plant consists of non-physical capital items, such as fees and expenses

⁴⁶⁷ *BP Pipelines*, 153 FERC ¶ 61,233 at P 88 (“[a]ny prudence determination, including this one, is highly *fact-specific* and based upon the record and circumstances presented by a particular record.”) (emphasis added); *New England Power Co.*, 31 FERC at 61,084 (stating that it is the “[Commission’s] duty to determine the prudence of *specific* costs...” (emphasis added).

⁴⁶⁸ We clarify one aspect of the Initial Decision, although it does not change the outcome of our determination. To the extent that the Initial Decision could be read as stating that *Anaheim* provides that for the evidentiary burden to shift to a utility, there must be a decision by a state agency disallowing proposed capital expenditures as imprudent, we disagree. Our reading of *Anaheim* reveals that the state disallowance of capital costs is just one of the examples where a serious doubt as to prudence of costs is raised. See *Anaheim*, 669 F.2d at 809 (“where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent”).

associated with the incorporation of the company, franchise fees, patent rights, and licenses.⁴⁶⁹

183. PG&E allocates CGI plant costs in two steps. First, whenever practical, PG&E identifies plant used by a single line of business and directly assigns that plant to the corresponding “Unbundled Cost Category” within which the line of business falls.⁴⁷⁰ PG&E allocates the remaining, “residual” CGI plant costs to Unbundled Cost Categories based on Operation and Maintenance (O&M) labor ratios.⁴⁷¹ For Period II, PG&E directly assigned roughly \$461.1 million of CGI costs to Network Transmission, and allocated \$191.3 million of CGI costs to Network Transmission through the use of O&M labor ratios.

1. Initial Decision

184. The Presiding Judge found that PG&E failed to establish that its direct assignment of CGI costs was just and reasonable. The Presiding Judge explained that in *Kern River Gas Transmission Co.*,⁴⁷² the Commission stated that costs should be directly assigned only if the method of assignment is consistent and the cost’s relationship to a specific line of business is obvious and reviewable.⁴⁷³ The Presiding Judge found that PG&E failed to demonstrate that the relationship between the CGI costs and the lines of business to which it seeks to assign those costs is reviewable.

185. The Presiding Judge found that *Kern River* is applicable to the CGI costs at issue in this proceeding, and governs the appropriateness of PG&E’s proposed direct assignment of CGI costs,⁴⁷⁴ because CGI plant items are functionally similar to A&G expense items, and that both items are often overhead in nature.⁴⁷⁵ The Presiding Judge noted that some parties contended that *Kern River* does not apply to CGI costs, invoking

⁴⁶⁹ Ex. S-0023 at 40.

⁴⁷⁰ Ex. PGE-0044 (Rebuttal Testimony of Beatrix H. Greenwell) at 3:16-20 (citing Ex. PGE-0010 at 9:10-10:1).

⁴⁷¹ Ex. PGE-0044 at 3:20-22.

⁴⁷² Opinion No. 386, 117 FERC ¶ 61,077 (2006) (*Kern River*).

⁴⁷³ Initial Decision, 165 FERC ¶ 63,001 at P 657 (citing *Kern River*, 117 FERC ¶ 61,077 at P 290).

⁴⁷⁴ *Id.* PP 659-675.

⁴⁷⁵ *Id.* P 659.

the Commission's decision in *Minnesota Power*, which held that General Plant costs should be allocated using labor allocators rather than plant allocators, and *Entergy*, in which the Commission applied *Minnesota Power* to both General and Intangible Plant.⁴⁷⁶ The Presiding Judge found those two cases to be distinguishable from the instant proceeding, explaining that in those cases, the Commission was choosing between the use of labor allocators and plant allocators, and was not addressing whether General and/or Intangible Plant costs should be directly assigned.⁴⁷⁷

186. The Presiding Judge explained that PG&E has the burden of establishing, among other things, that the relationships between its directly assigned costs and the function to which they are assigned are reviewable, including a showing that the documentation of its direct assignment of costs permits review of whether the transaction which gave rise to those costs actually occurred.⁴⁷⁸

187. The Presiding Judge stated that as part of her rebuttal testimony, PG&E's witness provided a three-page spreadsheet showing basic information regarding all CGI plant costs directly assigned during 2015.⁴⁷⁹ The Presiding Judge stated that PG&E's witness cited two planning orders as examples of documentation supporting the spreadsheet: one to install Supervisory Control and Data Acquisition for Electric Transmission amounting to approximately \$3.7 million, and another involving communications equipment costing \$100,000. However, the Presiding Judge found that PG&E's documentation submitted in support the planning orders and the explanations provided upon cross-examination were not sufficient to show that the alleged costs were incurred, and did not allow the "review of the assignment of such costs."⁴⁸⁰

188. Specifically, with respect to the \$3.7 million for Supervisory Control and Data Acquisition for Electric Transmission, the Presiding Judge stated that the only documentation that PG&E provided to support this transaction was a slightly more detailed spreadsheet which was not sufficient to show that the \$3.7 million in alleged

⁴⁷⁶ *Id.* P 660 (citing *Minn. Power & Light Co.*, 4 FERC ¶ 61,116, at 61,268, *aff'd*, 5 FERC ¶ 61,091 (1978) (*Minnesota Power*); *Entergy Services, Inc.*, 130 FERC ¶ 61,026, at P 88 (2010), *order on reh'g*, 143 FERC ¶ 61,120 (2013) (*Entergy*)).

⁴⁷⁷ *Id.* P 661.

⁴⁷⁸ *Id.* P 677.

⁴⁷⁹ *Id.* PP 678-679 (citing Ex. PGE-0044 at 4:22-5:3, 16-18).

⁴⁸⁰ *Id.* PP 678-697.

costs were incurred, much less to permit review of the assignment of such costs.⁴⁸¹ With respect to the second example, the Presiding Judge stated that after TANC submitted a data request, PG&E responded that it had no such invoice because the communications equipment had never been installed.⁴⁸²

189. The Presiding Judge stated in the data response, PG&E provided as an alternate example Planning Order 5753559 involving the installation of communications equipment related to the Cascade Substation in the amount of \$36,147.⁴⁸³ The Presiding Judge explained that the third page of PG&E's original spreadsheet shows that the costs expended under this planning order included approximately \$36,000 for general plant communications recorded to asset class EGP39700 (a common plant account) and directly assigned to Low Voltage Network Facilities.⁴⁸⁴ The Presiding Judge stated that the information that PG&E provided on Planning Order 5753559 in its data response is the sole documentation in the record purporting to support the information in its original spreadsheet. The Presiding Judge stated that *Kern River* requires that such documentation be sufficient to permit review of the relationship between the \$36,000 allegedly spent for communications equipment and the Low Voltage Network Facilities to which the alleged costs were assigned; however, the Presiding Judge found that PG&E's documentation fails to establish that the transaction listed under the planning order 5753559 even took place.⁴⁸⁵

190. Elaborating further, the Presiding Judge stated that PG&E's data response included a job estimate for Planning Order 5753559 which included another spreadsheet purporting to show detail regarding the communication and signaling equipment charged to the job. The Presiding Judge explained that the spreadsheet shows a breakdown of twelve work categories (e.g., engineering, station equipment and communication equipment); further breakdowns of the twelve work subcategories; and three tables setting out data for property installed, removal costs, and property retired.⁴⁸⁶ The Presiding Judge found that nothing in the data response supported PG&E's representations that Planning Order No. 5753559 involved an expenditure for communication equipment of roughly \$36,000 that has been recorded to asset class

⁴⁸¹ *Id.* P 681 & n.778 (citing Ex. PGE-0044 at 19-21).

⁴⁸² *Id.* P 682 & n.780 (citing Ex. TNC-0101 (PG&E Data Response) at 1).

⁴⁸³ *Id.* P 683 & n.781 (citing Ex. TNC-0101 at 1).

⁴⁸⁴ *Id.* P 684 (citing Ex. PGE-0044 at 18).

⁴⁸⁵ *Id.* P 685.

⁴⁸⁶ *Id.* PP 686-690.

EGP39700, much less the representation that this amount has been directly assigned to a transmission function.⁴⁸⁷ Specifically, the Presiding Judge pointed out a number of the various charges for communications equipment that appear in the data response and found that none add up to or fit the description of the roughly \$36,000 spent under Planning Order 5753559.⁴⁸⁸

191. The Presiding Judge added that TANC cross-examined PG&E's witness on this point, establishing that the costs of the only communications equipment shown in the detailed portion of the Planning Order No. 5753559 estimate that could have been directly assigned to any function totaled no more than \$12,000, and noted the contrast between that amount and the \$36,000 shown to be directly assigned in the original spreadsheet.⁴⁸⁹ The Presiding Judge stated that PG&E's witness referred to page 2 of the job estimate, which showed \$44,000 for communication equipment; however, the Presiding Judge noted that this data did not set forth the asset classes to which the costs were recorded, and does not show what, if any, portion of the costs could have been directly assigned.⁴⁹⁰

192. The Presiding Judge concluded that PG&E failed to demonstrate that its direct-assignment methodology for allocating CGI costs satisfies the *Kern River* test and therefore, concluded that PG&E must allocate all such costs based on O&M labor indicators.⁴⁹¹

2. **Briefs on Exceptions**

193. PG&E contends that the Presiding Judge properly ruled that *Kern River* applies to the CGI costs at issue, but incorrectly concluded that PG&E failed to meet the *Kern River* reviewability test.⁴⁹² PG&E estimates the Initial Decision's ruling would lower PG&E's TRR by approximately \$40 million, a reduction in rate base of approximately \$17 million and a correspondingly lower depreciation expense of \$23 million.⁴⁹³ PG&E states that

⁴⁸⁷ *Id.* at P 691.

⁴⁸⁸ *Id.* at PP 692-694.

⁴⁸⁹ *Id.* at P 696 and n.799 (citing Tr. 558:23-559:23 (Greenwell)).

⁴⁹⁰ *Id.* at P 697.

⁴⁹¹ *Id.* P 698.

⁴⁹² PG&E Brief on Exceptions at 62.

⁴⁹³ *Id.* at 63.

the spreadsheet reflected planning order attributes for all CGI plant costs to demonstrate that direct assigned costs were reviewable. PG&E asserts that reviewing a list of planning orders with direct-assigned CGI costs would clearly show by the planning order description, major work category, and funding identification number that the orders are Electric Transmission jobs.⁴⁹⁴ PG&E also asserts that these job estimates were provided in response to data requests. It argues the Presiding Judge attempted to tie the costs from the job estimates to the final plant additions amounts without recognizing the amounts included on the spreadsheet did not reflect final costs. PG&E contends that the Initial Decision failed to review record evidence from its rebuttal testimony that demonstrated that the relationship of CGI plant costs to Electric Transmission is obvious and reviewable.⁴⁹⁵ PG&E argues that it has demonstrated that its method meets the *Kern River* test and that CGI costs should be directly assigned to Electric Transmission.⁴⁹⁶

194. TANC and Six Cities contends that the Initial Decision erred by not following its precedent that CGI plant and related costs be allocated using a labor ratio as set forth in *Minnesota Power* and *Entergy* that alternate methods can only be used upon a showing that labor ratios would be unreasonable in the particular circumstances.⁴⁹⁷ Six Cities states that in Opinion No. 445,⁴⁹⁸ the Commission upheld an Initial Decision that found that the “use of labor cost ratios to allocate Administrative and General (A&G) and general and intangible plant (G&I) expenses was consistent with the Commission’s long-standing policy set forth in *Minnesota Power*.⁴⁹⁹ TANC further requests that the Commission grant exceptions and find that PG&E fails to meet its burden to show that labor ratios are unreasonable in this situation.⁵⁰⁰ TANC also argues that the Initial Decision errs in finding that *Kern River* is applicable to this proceeding, stating that *Kern River* addressed A&G costs, not the CGI costs at issue here, and fails to recognize the distinct differences between A&G expenses and CGI costs.⁵⁰¹

⁴⁹⁴ *Id.* at 64-65.

⁴⁹⁵ *Id.* at 65-66.

⁴⁹⁶ *Id.* at 67.

⁴⁹⁷ Six Cities Brief on Exceptions at 44-45; TANC Brief on Exceptions at 80-82.

⁴⁹⁸ *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 (2000).

⁴⁹⁹ Six Cities Brief on Exceptions at 46-48.

⁵⁰⁰ TANC Brief on Exceptions at 83.

⁵⁰¹ *Id.* at 83-84.

195. Trial Staff notes that the Initial Decision did not specify which labor allocator should be used, and states that PG&E should use a Period II labor allocator to allocate Period II CGI plant-related costs.⁵⁰²

3. Briefs Opposing Exceptions

196. PG&E reiterates that the Initial Decision was correct in finding that *Kern River* applies to its CGI costs, but erred in finding that PG&E had not met the reviewability prong of the *Kern River* test.⁵⁰³ PG&E asserts that it demonstrated that its direct assignment methodology did meet that reviewability test.⁵⁰⁴ PG&E states that Trial Staff fails to mention the sworn testimony of its own witness supporting the use of direct assignment of CGI costs under *Kern River*.⁵⁰⁵ PG&E adds that in the December 19, 2017 Joint Statement of Position on the Issues, Trial Staff stated that its position, based on its review of PG&E's testimony, was that PG&E has satisfied the *Kern River* test with respect to CGI plant allocation.⁵⁰⁶

197. TANC argues that *Kern River* is inapplicable because it addressed A&G costs, not CGI costs.⁵⁰⁷ TANC and Six Cities contend that, even if *Kern River* did apply, the Initial Decision properly found that PG&E has failed to show that the relationship between CGI costs and its Network Transmission function was obvious and reviewable.⁵⁰⁸ Finally, TANC states that it does not oppose, but believes unnecessary, Trial Staff's exception that PG&E use a Period II labor allocator to allocate Period II CGI plant-related costs.⁵⁰⁹

198. Trial Staff states that the Initial Decision properly found that the *Kern River* test applies to the appropriateness of PG&E's proposed direct assignment of CGI costs.⁵¹⁰ Trial Staff contends that TANC's reliance on *Minnesota Power* and *Entergy Services* is

⁵⁰² Trial Staff Brief on Exceptions at 40.

⁵⁰³ PG&E Brief Opposing Exceptions at 68-70.

⁵⁰⁴ *Id.* at 70.

⁵⁰⁵ *Id.* at 70-71.

⁵⁰⁶ *Id.* at 71 and n.252 (citing Joint Statement of Position on the Issues at 28).

⁵⁰⁷ TANC Brief Opposing Exceptions at 75-76.

⁵⁰⁸ *Id.* at 77-79; Six Cities Brief Opposing Exceptions at 54-57.

⁵⁰⁹ TANC Brief Opposing Exceptions at 80-81.

⁵¹⁰ Trial Staff Brief Opposing Exceptions at 29-30.

misplaced, explaining that in those two cases, the Commission was choosing between the use of labor allocators and plant allocators, and was not addressing whether CGI costs should be directly assigned.⁵¹¹ Trial Staff also asserts that TANC's claims that the Initial Decision fails to recognize the distinct differences between A&G expenses and CGI costs are not persuasive, stating that *Kern River* has broader applicability than simply A&G costs.⁵¹²

199. Trial Staff clarifies that it did not take exception to the Initial Decision's determination that PG&E failed the *Kern River* test.⁵¹³ Trial Staff also states that although its Initial Brief concluded that PG&E provided sufficient information demonstrating that the direct assignment and allocation methodologies are obvious and reviewable, the Initial Decision found that "PG&E did not put any of these documents in the record, so it is impossible to review their adequacy."⁵¹⁴

4. Commission Determination

200. We agree with the Presiding Judge that the *Kern River* test applies to the appropriateness of PG&E's proposed direct assignment of CGI plant costs. Although *Kern River* dealt specifically with A&G costs, the Commission stated that any cost can be accounted for on a direct basis regardless of the specific expense account, and that the test is specifically whether the method of directly assigning the cost is consistent and the relationship obvious and reviewable.⁵¹⁵ TANC and Six Cities contend that Commission precedent requires CGI costs to be allocated based on labor ratios, citing *Minnesota Power, Entergy Services*, and Opinion No. 445. However, in those cases, the Commission was deciding whether labor allocators or plant allocators should be used for allocating CGI costs, not whether CGI costs should be directly assigned. Thus, we find those cases are not applicable here. Accordingly, we find that the Presiding Judge was correct in applying *Kern River* in deciding whether PG&E's proposed direct assignment of CGI costs was just and reasonable.

⁵¹¹ *Id.* at 31-33.

⁵¹² *Id.* at 33-37.

⁵¹³ *Id.* at n.101.

⁵¹⁴ *Id.* (citing Initial Decision, 165 FERC ¶ 63,001 at P 685 n.786).

⁵¹⁵ *Kern River*, 117 FERC ¶ 61,077 at P 290 (stating that "the Commission's general policy is that direct costs should always be directly assigned and that indirect costs should be allocated by formula").

201. As the Presiding Judge explained, under the *Kern River* test, PG&E must establish that the relationship between the costs directly assigned and the Network Transmission function to which they are assigned is obvious and reviewable. First, PG&E must make a showing that its documentation supporting its direct assignment of costs permits review of whether the transactions which gave rise to those costs actually occurred. Then, PG&E's documentation must show that those costs are directly assignable. The Presiding Judge carefully evaluated the documentation provided by PG&E in rebuttal testimony and data response and found that the documentation was not sufficient to show that the alleged costs were even incurred, let alone sufficient to permit review of the assignment of such costs.⁵¹⁶ We agree.

202. Specifically, with respect to the \$3.7 million for Supervisory Control and Data Acquisition for Electric Transmission,⁵¹⁷ the Presiding Judge stated that the only documentation that PG&E provided to support this transaction was a slightly more detailed spreadsheet which was not sufficient to show that the \$3.7 million in alleged costs were incurred, much less to permit review of the assignment of such costs. Our review indicates that the only support that PG&E's offers that the \$3.7 million is directly assignable is its spreadsheet showing these costs as having a "Funding ID" of "Electric Transmission project."⁵¹⁸ We find that simply listing dollar amounts under a certain Funding ID is not sufficient to prove an obvious and reviewable relationship. With respect to Planning Order 5753559 involving the installation of communications equipment related to the Cascade Substation in the amount of \$36,000,⁵¹⁹ our review indicates that the Presiding Judge was correct in his finding that PG&E's documentation fails to establish that the transaction even took place, let alone that the cost were directly assignable. We find none of the various costs in the job estimate and spreadsheets included in PG&E's documentation match up with the \$36,000 amount that PG&E claims.

203. Accordingly, we affirm the Presiding Judge's conclusion that PG&E failed to demonstrate that its direct-assignment methodology satisfies the *Kern River* test and must allocate all such costs based on O&M labor indicators. With respect to Trial's Staff's recommendation that PG&E should use a Period II labor allocators to allocate Period II CGI costs, we disagree. Consistent with our finding in the section below addressing

⁵¹⁶ See *supra* PP 198-202.

⁵¹⁷ See Ex. PGE-0044.

⁵¹⁸ Ex. PGE-0044 at 16, 20.

⁵¹⁹ See Ex. TNC-0101.

allocators, we find that a Period I labor allocator calculated using 2015 recorded O&M labor costs is appropriate for allocating CGI costs in this case.⁵²⁰

G. O&M Expense Forecast

204. PG&E estimated \$285.798 million for 2017 Network Transmission O&M expenses, a 23.4% increase over the 2015 amount of \$231.641 million.⁵²¹ Trial Staff, Six Cities, and TANC proposed reducing the O&M expense by 6.52 to 7.74% and SWP proposed disallowing \$45 million from this expense, citing PG&E's tendency to over-forecast O&M expenses.⁵²²

205. PG&E also forecasted \$35.1 million in its Network Transmission O&M expenses as part of its Tower Coating Maintenance Program.⁵²³ PG&E commenced the program in 2016, and anticipated spending over \$400 million between 2016 and 2022 to assess and repaint approximately 6,000 transmission structures with non-lead-based paint.⁵²⁴

1. Initial Decision

206. The Presiding Judge noted that PG&E's witness does not justify PG&E's forecasted O&M expenses for three accounts included in PG&E's Network Transmission rates.⁵²⁵ The Presiding Judge notes that the failure to discuss Account 565, Transmission of Electricity by Others, leaves \$15.786 million of PG&E's forecasted transmission O&M expenses unaccounted for.⁵²⁶ The Presiding Judge also noted "contrary evidence," and explained that PG&E's O&M forecast cannot have been reasonable because PG&E admitted that its forecast expense includes a reserve fund intended to offset any litigation risk and refund obligation that might result from this proceeding.⁵²⁷ The Presiding Judge stated that PG&E admitted the litigation risk assessment is made after its transmission rate case is filed. Therefore, the Presiding Judge found that PG&E deliberately inflated

⁵²⁰ See *infra* P 249.

⁵²¹ Ex, PGE-0006 at 4:17-18.

⁵²² Initial Decision, 165 FERC ¶ 63,001 at PP 700-701.

⁵²³ Ex. PGE-0006 at 19:20.

⁵²⁴ Ex, TNC-0021 at 233.

⁵²⁵ *Id.* PP 702-709 (citing Ex. PGE-0006 (Testimony of Jessica Tsang)).

⁵²⁶ *Id.* PP 703-706.

⁵²⁷ *Id.* P 710.

its transmission O&M expense, thus lessening the credibility of its forecast. As a result, the Presiding Judge found that PG&E fails to satisfy the first prong of the *Chatham* test.⁵²⁸

207. The Presiding Judge noted that under *Chatham*, PG&E could demonstrate the reasonableness of its O&M forecast if it could establish that its forecasts have proven accurate over the years. Thus, the Presiding Judge examined PG&E's historical forecasts and determined that they have not been accurate, and thus fail to satisfy the second prong of the *Chatham* test. Six Cities, TANC, SWP, and Trial Staff applied different methodologies but all concluded that PG&E inflated its average forecasted O&M expense by amounts ranging from weighted average of 6.52% to a simple average 8.06% for the 2006-2011 and 2013-2015 timeframes.⁵²⁹ PG&E argued that while they have not modified their forecasting methodology since 2010 their forecasts are improving. The Initial Decision then considered PG&E's actual Network Transmission O&M expenses of \$220,664,664 through November 2017 and concluded that actual values O&M expense should be \$237,100,554 by adding PG&E's budgeted Network Transmission O&M expense for December. Therefore, the Presiding Judge determined that PG&E must reduce its Network Transmission O&M expense forecast by \$48,697,531 million for that expense to be just and reasonable.⁵³⁰

208. The Presiding Judge then reviewed TANC's assertion that the \$35.1 million PG&E forecasted for Network Transmission O&M expenses to recoat towers with non-lead based paint was imprudent. The Presiding Judge noted the prudence of PG&E's 2017 tower coating maintenance expenditures is not listed in the Joint Statement of Issues, and therefore TANC's challenge was outside of the scope of issues in the proceeding.⁵³¹ The Presiding Judge then noted that TANC's witness, proposed a reduction of \$2.419 million in O&M based on the company's reduced forecast for that

⁵²⁸ *Id.* P 719.

⁵²⁹ *Id.* P 721.

⁵³⁰ *Id.* PP 724-725. The Presiding Judge observed that, through November 2017, PG&E's Network Transmission O&M expenses totaled \$220,644,544 and PG&E had budgeted \$16.436 million for December 2017. The Presiding Judge then states that the total of these numbers, \$237,100,544, is appropriate for PG&E's Network Transmission O&M expense.

⁵³¹ *Id.* P 728. The Presiding Judge nevertheless reviewed the invoices TANC submitted as evidence and noted there could be plausible explanations for the expenditures at issue but because TANC failed to raise the issue through its prudence expert PG&E was deprived of the opportunity to file rebuttal testimony. *Id.* P 733.

program but did not question the prudence entirely.⁵³² The Presiding Judge dismissed the forecast concerns, stating that his proposed adjustments in the preceding section addressing PG&E's O&M Expense Forecast, which obviated the need to reduce the forecast further.⁵³³

2. Briefs on Exceptions

209. PG&E disagrees with the Initial Decision's assessment that its O&M forecast was not reasonable when made, noting that forecasts will never be exactly correct. PG&E asserts that estimates should not be rejected because they vary from actual data, and that doing so would result in historic-cost ratemaking.⁵³⁴ PG&E notes that the Presiding Judge would not have had access to actual data had the case gone to hearing in 2017, and therefore would not have been able to compare actual data to PG&E's forecast.

210. PG&E also defends its process, whereby their internal budgets are prepared after the forecast is prepared and filed, and its position to spend less than the full forecasted request, citing the regular challenges from intervenors in rate cases where the parties settle the rates at levels below the request. PG&E states that spending can be adjusted throughout the year to ensure safe and reliable operations of its transmissions facilities.⁵³⁵ PG&E argues that the forecasts were reasonable when made in April and May of 2016 and the Commission should accept the forecasts and resulting rates. Therefore, the Commission should not adopt the trued-up calculation for O&M expenses proposed by the Presiding Judge.⁵³⁶

211. TANC believes that the Initial Decision incorrectly determined PG&E's Tower Coating Maintenance Program is not imprudent. TANC states the Initial Decision failed to find the program expenditures imprudent despite evidence indicating that 36 of 71 towers a contractor surveyed did not have lead-based paint, thus did not require recoating. TANC argues the Presiding Judge did not adequately consider evidence regarding PG&E's performance under the 2016 contract during cross-examination. TANC maintains that the contract is important because it illustrates that many of the towers did not qualify for recoating, and this could indicate that future expenditures under

⁵³² *Id.* P 729 (citing Ex. TNC-0018 at 56:1-21 (Testimony of David Cohen)).

⁵³³ *Id.* P 729 & n.846.

⁵³⁴ PG&E Brief On Exceptions at 67 (citing *Pub. Serv. Co. of N.M. v. FERC*, 832 F.2d at 1217 (*Public Service Company of New Mexico*)).

⁵³⁵ *Id.* at 70-71.

⁵³⁶ *Id.* at 71.

the tower maintenance program could also fail to meet the Commission's definition for prudent management action.⁵³⁷

212. TANC also states that the Initial Decision incorrectly found the prudence of the tower maintenance program to be outside the scope of this proceeding. TANC argues that the program is part of PG&E's O&M expense and is therefore within scope.⁵³⁸ TANC also contends that the Initial Decision incorrectly failed to consider fluctuating cost and scope estimates for tower maintenance. TANC notes PG&E's inability to provide a reasonable forecast for the project and therefore should render the forecasted tower maintenance costs unjust and unreasonable.⁵³⁹ Therefore, TANC argues PG&E's forecast for O&M expenses for its Tower Coating Maintenance Program should be adjusted.

3. **Briefs Opposing Exceptions**

213. SWP, Trial Staff, Six Cities, and TANC support the Initial Decision's determination regarding the accuracy of PG&E's forecast, generally raising two arguments: (1) PG&E has a history of over-forecasting O&M expense, and has done so for seven of the previous eight years, and (2) PG&E keeps a "reserve fund" by reducing O&M expense below its forecasted levels. These points support the argument that PG&E's O&M expense forecasts were not reasonable when made (a requirement of *Chatham*).⁵⁴⁰ Trial Staff, citing *Public Service Company of New Mexico*, explains that forecasts can be rejected if it is found that relying on them would "yield unreasonable results."⁵⁴¹ Trial Staff argues that because the forecast was not reasonable when made and should be rejected, it is fair for the Presiding Judge to use actual expenses through November 2017 together with the budgeted amount for December of that year to determine a just and reasonable O&M expense.

214. PG&E agrees with the Initial Decision finding that its Tower Coating Maintenance Program cannot be found imprudent. PG&E also agrees with the Presiding Judge that, due to the timing of TANC's arguments regarding the Tower Coating Maintenance Program, PG&E was not able to file rebuttal testimony to address TANC's argument

⁵³⁷ *Id.* at 87-88.

⁵³⁸ *Id.* at 88-89.

⁵³⁹ *Id.* at 90-91.

⁵⁴⁰ *Chatham*, 662 F.2d at 29.

⁵⁴¹ Trial Staff Brief Opposing Exceptions at 38.

because TANC expressed the concern in the context of the forecast, and not concern with the implementation of the program.⁵⁴²

4. Commission Determination

215. We find that the Presiding Judge correctly determined that PG&E has not satisfied the test in *Chatham* to support its O&M expense forecasts. Under the first prong of *Chatham*, “[t]he utility must demonstrate that its estimates were reasonable when made, either by explaining the chain of reasoning that is employed to arrive at its projections, or by comparing its estimates with actual data, and so establishing their accuracy.”⁵⁴³ Under the second prong of *Chatham*, a utility can demonstrate that its forecast is reasonable if it can establish that its forecasts have been accurate over the years.⁵⁴⁴ Our review of the evidence in the record and the analysis of the Presiding Judge in the Initial Decision shows that PG&E over-forecasted its O&M expense.⁵⁴⁵ Additionally, PG&E’s practice of holding an amount in reserve for litigation risk, as confirmed by PG&E’s witness, further increases the amount by which its O&M expenses are over-forecasted. Therefore, we affirm the Presiding Judge’s finding that PG&E failed to demonstrate its forecast for 2017 Network Transmission O&M expenses were just and reasonable and the decision to use the actual data for the case year to calculate the O&M expense. Accordingly, PG&E must reduce its O&M expense forecast by \$48,697,531 to \$220,664,554.

216. Additionally, we find the Presiding Judge’s analysis regarding PG&E’s Tower Coating Maintenance Program is reasonable and based on record evidence, and we therefore affirm it. For example, the Presiding Judge noted that TANC’s witness did not challenge the prudence of any of PG&E’s tower coating maintenance expenditures; rather, he focused on whether PG&E had supported its forecasts for the costs of the program.⁵⁴⁶ Moreover, the Presiding Judge reasonably concluded that it was “highly questionable” whether TANC’s challenge to two invoices associated with the program

⁵⁴² PG&E Brief Opposing Exceptions at 71-72.

⁵⁴³ Initial Decision, 165 FERC ¶ 63,001 at PP 700 (citing *Chatham* 662 F.2d at 29).

⁵⁴⁴ *Id.* P 720.

⁵⁴⁵ *Id.* PP 721-724.

⁵⁴⁶ *Id.* P 729.

raised reasonable doubts as to the prudence of the costs PG&E incurred.⁵⁴⁷ Finally, in response to TANC's assertion that not addressing the condition of the towers prior to coating raised serious doubts as to the prudence of the expenditures, the Presiding Judge reasonably found that for PG&E to assess the condition of thousands of towers "might prove a needless expenditure of company money and resources."⁵⁴⁸ Therefore, we affirm the Presiding Judge's decision to allow costs for the program, and allow PG&E's forecasted Network Transmission O&M expenses to include \$35.1 million for its Tower Coating Maintenance Program.

217. We also affirm the Presiding Judge's determination that the reduced *forecast* for the Network Transmission O&M expense attributable to the Tower Coating Maintenance Program has been addressed by reducing the overall Network Transmission O&M expense by \$48,697,531. The Presiding Judge's adjustment is intended to allow PG&E to recover its actual costs. Reducing the Network Transmission O&M expenses by an additional \$2.419 million, as proposed by TANC, is therefore unnecessary.

H. A&G Expenses

218. PG&E forecasted its Network Transmission A&G expenses at \$84.199 million for 2017.⁵⁴⁹ PG&E estimated A&G expenses in two steps: (1) estimating total company A&G expenses; and (2) unbundling A&G expenses to Unbundled Cost Categories, including Network Transmission.⁵⁵⁰ PG&E unbundles its A&G expenses into Unbundled Cost Categories using O&M expense labor ratios.⁵⁵¹ PG&E forecasts company-wide A&G expenses of \$1,368,935,000 for 2017.⁵⁵² PG&E allocates \$907.451 million (66.29%) of the foregoing amount to its Electric Department and \$84.199 million (9.28%) of that amount to Network Transmission.⁵⁵³ The O&M labor ratios that PG&E

⁵⁴⁷ *Id.* P 733. The Presiding Judge also noted that TANC failed to raise this issue through its prudence expert, thereby depriving PG&E the opportunity to provide rebuttal testimony on this issue. *Id.*

⁵⁴⁸ *Id.* P 737.

⁵⁴⁹ *Id.* P 740 (citing Ex. PGE-0026 at 3).

⁵⁵⁰ Ex. PGE-0007 (Testimony of Judith Gutierrez) at 4:13-22.

⁵⁵¹ *Id.* at 5:7-12.

⁵⁵² Ex. PGE-0026 at 3.

⁵⁵³ *Id.*

uses are recorded adjusted 2015 ratios.⁵⁵⁴ The adjustment is necessary because PG&E implemented a new cost model effective January 2016, which affects how A&G expenses are treated.⁵⁵⁵

1. Initial Decision

219. The Presiding Judge found that PG&E's A&G expense forecast was just and reasonable at the time it was made.⁵⁵⁶ The Presiding Judge stated that under the test set out in *Chatham*,⁵⁵⁷ PG&E may establish reasonableness "either by explaining the chain of reasoning that it employed to arrive at its projections, or by comparing its estimates with actual data, and so establish their accuracy."⁵⁵⁸ The Presiding Judge found that PG&E's witness satisfied prong 1 of the *Chatham* test when she testified that PG&E's uses a two-step forecast methodology for estimating A&G expenses by (1) estimating the total company's A&G expenses; and (2) unbundling those expenses, including Network Transmission, to Unbundled Cost Categories.⁵⁵⁹

220. The Presiding Judge rejected TANC's and Trial Staff's claim that based on PG&E's forecast history, between 2006–2011 and 2013–2015, PG&E generally over-forecasted its A&G expenses.⁵⁶⁰ The Presiding Judge found the participants were only able to show that PG&E's forecasted A&G expenses exceeded actual expenses by as little as 2.0% and 2.6%.⁵⁶¹ Further, the Presiding Judge found that historically PG&E had under-forecasted its A&G expenses by an average of 1.0%.⁵⁶² Therefore, the Presiding Judge found that PG&E made a *prima facie* case that its A&G forecast was reasonable.⁵⁶³ Further, the Presiding Judge found that based on the record, PG&E's

⁵⁵⁴ Ex. PGE-0012 (Testimony of David Hartman) at 8:1-19.

⁵⁵⁵ Ex. PGE-0007 at 2:10-21.

⁵⁵⁶ Initial Decision, 165 FERC ¶ 63,001 at P 751.

⁵⁵⁷ 662 F.2d 23.

⁵⁵⁸ Initial Decision, 165 FERC ¶ 63,001 at P 740 (citing *Chatham*, 662 F.2d at 29).

⁵⁵⁹ *Id.* P 741 (citing Ex. PGE-0007 at 4:13-22); *Id.* P 743.

⁵⁶⁰ *Id.* PP 747–49.

⁵⁶¹ *Id.* P 751.

⁵⁶² *Id.* (citing Ex. PGE-0041 (Rebuttal Testimony of Judith Gutierrez) at 8, tbl. 3).

⁵⁶³ *Id.*

increase in A&G labor expenses and decrease in Customer Care expenses is plausible and well documented and rejected Six Cities and Trial Staff's proposal to reallocate part of PG&E's A&G costs to Customer Care.⁵⁶⁴

221. The Presiding Judge also found PG&E's allocation of Edison Electric Institute (EEI) dues was just and reasonable.⁵⁶⁵ The Presiding Judge reasoned that PG&E is a member of EEI and it assigns 18.9% of its membership dues to its Network Transmission customers.⁵⁶⁶ The Presiding Judge explained that in *Delmarva Power & Light Co.*,⁵⁶⁷ the Commission found utilities may "allocate EEI contributions to wholesale customers only to the extent it can demonstrate that the contributions were used for a permissible purpose."⁵⁶⁸ The Presiding Judge found the record reflects that EEI's use of PG&E's dues does not determine how the utility must allocate those dues to its ratepayers.⁵⁶⁹ The Presiding Judge stated that, following a CPUC decision, PG&E allocates 43% of its dues to a FERC account that benefits stockholders rather than ratepayers.⁵⁷⁰ According to the Initial Decision, PG&E equally allocates the remaining 56.7% of the dues to generation, transmission, and distribution. The Presiding Judge found this allocation to be just and reasonable.⁵⁷¹ The Presiding Judge also concluded that witnesses sponsored by Trial Staff and PG&E have established that PG&E's contributions to EEI provide benefits to Network Transmission customers.⁵⁷²

⁵⁶⁴ *Id.* P 766.

⁵⁶⁵ *Id.* P 780.

⁵⁶⁶ *Id.* P 768 (citing Ex. S-0010 (Testimony of Yewande Bayly) at 16:9-11).

⁵⁶⁷ 58 FERC ¶ 61,169, at 61,509 (1992) (*Delmarva*).

⁵⁶⁸ Initial Decision, 165 FERC ¶ 63,001 at P 769 (citing *Delmarva*, 58 FERC ¶ at 61,509; *ISO New England Inc.*, 117 FERC ¶ 61,070, at P 40 (2006) ("[T]he Commission has generally stated that public outreach and educational expenses are properly recoverable from ratepayers and lobbying expenses are not. . . .")).

⁵⁶⁹ *Id.* P 774.

⁵⁷⁰ *Id.*

⁵⁷¹ *Id.* (citing CPUC Decision 14-08-031, Decision Authorizing PG&E's GRC Revenue Requirement for 2014-2016, A.12-11-009 at 261-63); *id.* P 780.

⁵⁷² *Id.* P 776 (citing Ex. S-0010 at 16:12-17:5 (quoting Ex. S-0013 (Trial Staff Forecast Analysis of O&M and A&G) at 28-30)).

222. Further, the Presiding Judge found that PG&E allocates only \$11.338 million out of its 2017 forecasted \$327 million in pension contributions to Network Transmission customers.⁵⁷³ The Presiding Judge stated that PG&E allocates pension benefits the same way the utility allocates its entire pension and benefits costs.⁵⁷⁴ The Presiding Judge found that PG&E was forecasting the same amount of pension benefits as it had in 2015, which the Commission deemed prudent.⁵⁷⁵ The Presiding Judge rejected TANC's opposition to PG&E's allocation, reasoning that TANC failed to raise doubt about the prudence of pension rates. Accordingly, the Presiding Judge found the \$11.338 million of allocated pension costs to Network Transmission to be just and reasonable.⁵⁷⁶

2. **Briefs on Exceptions**

223. Six Cities states that the Commission should reverse the Presiding Judge's finding that PG&E's A&G labor expenses were just and reasonable.⁵⁷⁷ Six Cities reiterates its arguments asserting that the record reflects a discrepancy from Period I to Period II between PG&E's forecasted employee additions or reduction and the total change in labor costs, and argues that PG&E failed to justify this "mismatch."⁵⁷⁸ Six Cities argues that PG&E failed to meet its burden of proof under FPA section 205 to demonstrate that its proposed rate is just and reasonable, and that it "must ensure that there is a sufficient evidentiary record for the Commission to make a reasoned decision."⁵⁷⁹

224. Next, Six Cities criticizes PG&E's explanation that the discrepancy is due to its new cost allocation methodology.⁵⁸⁰ Six Cities argues that the Initial Decision should not

⁵⁷³ *Id.* PP 786, 790.

⁵⁷⁴ *Id.* P 791.

⁵⁷⁵ *Id.* PP 793-94.

⁵⁷⁶ *Id.* P 795.

⁵⁷⁷ Six Cities Brief on Exceptions at 48.

⁵⁷⁸ *Id.* at 48-49.

⁵⁷⁹ *Id.* at 49-50 (citing *Indicated SPP Transmission Owners v. Sw. Power Pool, Inc.*, 165 FERC ¶ 61,005, at P 10 (2018) ("[A]ny . . . proponents of the revised ATRR, still [have] the burden of proof to demonstrate that the rate is just and reasonable, and must ensure that there is a sufficient evidentiary record for the Commission to make a reasoned decision")).

⁵⁸⁰ *Id.*

have relied the explanation because it lacked specific and supporting evidence.⁵⁸¹ Six Cities also claims that the Presiding Judge based his conclusion on Exhibit PGE-0025⁵⁸² despite the explanation that the table in the exhibit is an example of how the methodology works.⁵⁸³ In addition, Six Cities argues that the Commission should apply its proposed adjustment to PG&E's A&G expenses.⁵⁸⁴ Six Cities claims the Commission should require PG&E to adjust its forecasted employee additions or reductions by reclassifying the employee headcount and labor costs to a Customer Care expense.⁵⁸⁵

225. TANC also disagrees with the Initial Decision's finding that PG&E's A&G forecast was reasonable when made.⁵⁸⁶ TANC believes the Presiding Judge did not engage in reasoned decision making because the Initial Decision fails to consider evidence that PG&E over-forecasted A&G expenses for Maintenance of General Plant, Office Supplies and Expenses, and Property Insurance.⁵⁸⁷ Additionally, TANC argues the Presiding Judge erred in dismissing its witness' testimony that demonstrates PG&E's failure to provide a reasoned explanation that it will not reduce its 2017 A&G expenses forecast regardless of its projected decline in "Gross Load at Area Out" during the test year.⁵⁸⁸ Further, TANC contends that the Initial Decision does not properly apply *Delmarva* to PG&E's recovery of EEI dues.⁵⁸⁹ According to TANC, *Delmarva* holds that the Commission allows utilities to "allocate EEI contributions to customers only to the extent such contributions are for research and development programs which the wholesale customer themselves could not contribute."⁵⁹⁰ TANC states that, during testimony, PG&E's witness admitted that the utility does not know how EEI spends its

⁵⁸¹ *Id.* at 50.

⁵⁸² *Id.* (citing Ex. PGE-0025 at 68).

⁵⁸³ *Id.* at 50–51.

⁵⁸⁴ *Id.* at 52.

⁵⁸⁵ *Id.* at 53–54.

⁵⁸⁶ TANC Brief on Exceptions at 91.

⁵⁸⁷ *Id.* at 91–92.

⁵⁸⁸ *Id.* at 93.

⁵⁸⁹ *Id.* at 94.

⁵⁹⁰ *Id.* (citing *Delmarva*, 58 FERC at 61,509).

dues.⁵⁹¹ Therefore, TANC requests the Commission find that it is not just and reasonable to allow PG&E to include EEI expenditures in its TO18 revenue requirement.⁵⁹² Finally, TANC disagrees with the Initial Decision's approval of PG&E's pension contributions claiming the ruling conflicts with FPA section 205.⁵⁹³

3. **Briefs Opposing Exceptions**

226. PG&E argues that Six Cities' and TANC's exceptions have no merit. PG&E's states that the Presiding Judge correctly found that its witness made a *prima facie* case that its A&G forecast was reasonable.⁵⁹⁴ Therefore, PG&E claims it met its burden of proof.⁵⁹⁵ Additionally, PG&E rejects Six Cities' argument about its proposed adjustment to Customer Care expenses, and states that the Initial Decision properly addressed this issue when it found that PG&E's explanation that the Customer Care labor expense decrease from 2015-2017 is primarily a result of the implementation of changes in how PG&E allocates certain costs was plausible and well documented.⁵⁹⁶ Further, PG&E criticizes TANC for challenging the Initial Decision's ruling on recovery of dues paid to EEI.⁵⁹⁷ PG&E argues that the Presiding Judge properly rejected TANC's argument.⁵⁹⁸

227. Trial Staff agrees with the Presiding Judge's finding that PG&E's allocation of its EEI dues to Network Transmission is just and reasonable.⁵⁹⁹ Trial Staff argues that TANC failed to raise the issue that EEI uses the contributions PG&E seeks to recover from Network Transmission for "lobbying, advertising, research, or any other specific purpose."⁶⁰⁰ Trial Staff contends that just because PG&E does not have a specific breakdown of the allocation of EEI dues does not mean it is unaware of how the dues

⁵⁹¹ *Id.* at 95.

⁵⁹² *Id.*

⁵⁹³ *Id.* at 96.

⁵⁹⁴ PG&E Brief Opposing Exceptions at 72.

⁵⁹⁵ *Id.*

⁵⁹⁶ *Id.* at 73.

⁵⁹⁷ *Id.* at 74–75.

⁵⁹⁸ *Id.* at 75.

⁵⁹⁹ Trial Staff Brief Opposing Exceptions at 40.

⁶⁰⁰ *Id.* at 40–41.

support the company and benefit customers.⁶⁰¹ Therefore, Trial Staff concludes that the Initial Decision's finding is correct.⁶⁰²

4. Commission Determination

228. We affirm the Presiding Judge's findings. We find that the issues raised by Six Cities and TANC in their briefs on exceptions have been thoroughly addressed by the Presiding Judge in the Initial Decision in paragraphs 740-795. Specifically, the Presiding Judge considered the expert testimony from Six Cities and TANC, as well as the rebuttal to that testimony from PG&E's expert witnesses and PG&E's expert witnesses' cross-examination. The Presiding Judge's findings are further supported by the record evidence, as detailed in the Initial Decision. Neither Six Cities nor TANC present arguments in their briefs on exceptions that warrant a different outcome. We find no reason to revisit Presiding Judge's findings. We therefore affirm the Initial Decision on the issue of A&G Expenses.

I. Allocators

229. PG&E uses Line-of-Business (LOB) allocators to allocate common costs between the Electric and Gas Departments. Once these LOBs are determined, PG&E then determines which Electric costs will be allocated directly to Network Transmission.⁶⁰³ As relevant here, PG&E used recorded Period I O&M labor expenses, adjusted to reflect a new cost model the company adopted in 2016, to calculate the LOB allocators, resulting in an allocator of 66.29% to the Electric Department and 33.71% to the Gas Department, and allocated 9.28% of the Electric LOB to Network Transmission.⁶⁰⁴

230. PG&E also sought to recover a portion of costs associated with its Short Term Incentive Pay (STIP), which is part of its compensation package, allocated in Account 920, A&G salaries.⁶⁰⁵ The STIP serves as an annual performance-based bonus. In 2017, PG&E estimated it would spend \$170.747 million on STIP, of which 66.29%, or \$113.186 million would be allocated to the Electric Department. Of that, 9.28% would be

⁶⁰¹ *Id.* at 42.

⁶⁰² *Id.* at 40.

⁶⁰³ Initial Decision, 165 FERC ¶ 63,001 at P 797.

⁶⁰⁴ *Id.* PP 798, 827.

⁶⁰⁵ Ex. PGE-0007 at 5:13-6:19.

allocated to Network Transmission and 35.74% would be capitalized and put into its rate base.⁶⁰⁶ As a result, PG&E's TRR includes a STIP component of \$6.749 million.⁶⁰⁷

1. Initial Decision

231. The Presiding Judge found PG&E's proposed allocators to be reasonable, subject to one adjustment. Six Cities contested PG&E's proposed allocators and instead suggested 64.74% to the Electric Department with 9.785% of that allocated to Network Transmission would be more appropriate. In support, Six Cities stated that the Electric Department is expected to lose more employees than the Gas Department. Trial Staff adopted Six Cities' proposed calculation, except Trial Staff's witness reclassified A&G costs to Customer Care.⁶⁰⁸ The Presiding Judge rejected Six Cities' proposed calculation, explaining that the O&M costs previously established are not in dispute.⁶⁰⁹ The Presiding Judge further explained that using actual 2015 (Period I) recorded labor costs to allocate common cost, and not projected labor costs, is the most accurate way of allocating such costs between Electric and Gas Departments.⁶¹⁰ Six Cities asserted that \$435,000 for O&M labor expense for vegetation management was incorrectly recorded and must be added to the Network Transmission labor expenses.⁶¹¹ The Presiding Judge accepted

Six Cities' vegetation management correction, which increased the Electric Department cost allocator from 66.29 to 66.30% of the company-wide common costs and increased the Network Transmission costs to 9.32% of the Electric Department costs.⁶¹²

232. The Presiding Judge stated that using Period II data would be logical to predict future costs. However, he asserted that neither Six Cities nor Trial Staff provided a workable forecast for PG&E's future Electric Department costs. Therefore, the Presiding

⁶⁰⁶ Ex. PGE-026 at 16.

⁶⁰⁷ *Id.* at 9-15.

⁶⁰⁸ Initial Decision, 165 FERC ¶ 63,001 at P 813.

⁶⁰⁹ *Id.* P 815.

⁶¹⁰ *Id.* P 825.

⁶¹¹ *Id.* PP 799-828.

⁶¹² *Id.* P 826. Six Cities pointed out that vegetation management was incorrectly recorded as an O&M labor expense decrease in PG&E's Period I statement, and should instead be added to the 2015 Network Transmission O&M labor expenses.

Judge stated that the 2015 O&M labor costs provide the best foundation to determine PG&E's allocators.⁶¹³

233. PG&E proposed a STIP component of \$6.749 million in its TRR. The Presiding Judge determined STIP metrics are specific to certain parts of the company, and identified the components that directly benefit electric customers.⁶¹⁴ TANC and SWP contended that few of the performance measures in PG&E's STIP have to do with transmission service.⁶¹⁵ Additionally, the Presiding Judge stated that Commission precedent requires the exclusion of expenses that do not benefit ratepayers.⁶¹⁶ The Presiding Judge determined that the Employee Safety component of the STIP (16%) is allowable, and notes 10.61% of is applicable to the Electric Department and correspondingly 1.49% to Network Transmission. The Presiding Judge determined the three remaining components, accounting for 20% of STIP costs including, (1) emergency response to 911 calls (5%), (2) duration of electric outages (5%), and (3) downed T&D wires (10%) should be allocated to Network Transmission customers based on O&M labor allocators solely within the Electric Department and these components do not benefit gas customers.⁶¹⁷ "Earnings from Operations" (2%) was disallowed, with the Presiding Judge explaining that approving expenses that help raise capital will enable PG&E to recover expenses that benefit shareholders but do not benefit the ratepayers.⁶¹⁸ Additionally, the Presiding Judge disallowed the Customer Satisfaction Score (15%), noting it benefits only retail customers. The Presiding Judge therefore allowed the following components in the STIP benefit electric customers and may be allocated to the Electric Department: (1) emergency response to 911 calls (5%), (2) duration of electric outages (5%), and (3) downed T&D wires (10%) and (4) Employee Safety (10.61%), for a total of 30.61%, or \$52.26 million. Of that, 9.32%, or \$4.871 million, should be allocated to Network Transmission.⁶¹⁹ The Presiding Judge also reduced the capitalization factor from 35.74 to 35.34% of STIP costs allocated to Network

⁶¹³ *Id.* PP 814-815.

⁶¹⁴ *Id.* PP 855-860.

⁶¹⁵ *Id.* P 843.

⁶¹⁶ *Id.* P 844 (citing *Public Service Company of New Mexico*, 813 F.2d at 456; *Trunkline Gas Co.*, 90 FERC ¶ 61,017, at 61,064 (2000)).

⁶¹⁷ *Id.* P 857.

⁶¹⁸ *Id.* P 848 (citing *Public Service Company of New Mexico*, 813 F.2d at 448, 456).

⁶¹⁹ *Id.* P 859.

Transmission, which PG&E has not protested.⁶²⁰ As a result, the Presiding Judge determined the TRR for Network Transmission customers should include a STIP component of \$3.15 million,⁶²¹ which represents a reduction of approximately \$3.6 million from what PG&E proposed.

2. Brief on Exceptions

234. Six Cities argues that PG&E should use forecasted Period II data to calculate LOB allocators, instead of relying upon recorded Period I data as the Presiding Judge concluded.⁶²² Six Cities explains that the number of employees in the Electric Department is expected to go down relative to the number in the Gas Department, and therefore asserts that the allocator adopted by the Presiding Judge is overstated. Six Cities states that an Electric LOB allocation of 66.3% is unjust and unreasonable and PG&E should use forecasted Period II values instead, resulting in an Electric LOB allocation of 64.741%.⁶²³

235. PG&E disagrees with the Initial Decision's reduction of the STIP, and the determination that its STIP metrics are specific to individual components of the company and there for cannot be charged to Network Transmission Customers.⁶²⁴ PG&E argues that certain components of the STIP, such as "Earning from Operations," enable PG&E to raise capital at a competitive rate and thus, should be allowed. PG&E also notes that the customer care component of the STIP should be allowed because it benefits service to all customers, not exclusively retail customers.⁶²⁵ PG&E concludes that STIP is part of the overall compensation package and is less expensive for customers long-term than an across-the-board pay increase.

3. Briefs Opposing Exceptions

236. PG&E defends its LOB and Network Transmission allocators, agreeing with the Initial Decision that Six Cities' approach to estimating its allocators is flawed. PG&E

⁶²⁰ *Id.* PP 861-863.

⁶²¹ *Id.* P 864.

⁶²² Six Cities Brief on Exceptions at 58.

⁶²³ *Id.* at 59.

⁶²⁴ PG&E Brief on Exceptions at 73.

⁶²⁵ *Id.* at 75.

notes the modifications it has made to its allocation methodology, and that Six Cities' analysis that relies on upon headcount and escalation factors is inaccurate.⁶²⁶

237. TANC and CDWP concur with the Initial Decision's finding that the "Earnings from Operations" metric should be borne by shareholders because it does not give more than incidental benefits to transmission customers.⁶²⁷ SWP asserts that shareholders should fund any additional compensation to increase the financial performance, and notes the Commission has previously required costs that do not benefit ratepayers be excluded, citing *Public Service Company of New Mexico*, in which advertising costs were excluded.⁶²⁸ TANC and SWP also agree that Customer Satisfaction should not be included in the Network Transmission costs because customer care benefits primarily distribution customers.

4. Commission Determination

238. We affirm the Initial Decision regarding LOB allocators, finding the Presiding Judge's rationale to rely on known and measurable data as a basis for determining the allocators was reasonable and supported by the record. We note that Period II data can be used to project future 2017 costs; however, an accurate forecast of Period II data was not provided in this proceeding, and therefore we will rely on the known data from the Period I O&M labor expenses. Accordingly, we affirm the Presiding Judge's decision to accept PG&E's methodology to calculate LOB allocators using recorded Period I O&M labor expense data. Additionally, we accept the Presiding Judge's directive to recalculate PG&E's Network Transmission O&M labor expenses to include \$435,000 for vegetation management costs that were incorrectly recorded. Therefore, we affirm the Presiding Judge's decision to adjust PG&E's proposed Electric Department labor allocator to 66.30% of the company-wide common costs to the Electric Department, and a Network Transmission allocator of 9.32% of the Electric Department costs, or 6.18% of common costs.

239. We also affirm the Presiding Judge with respect to his conclusions addressing the allocation of STIP costs. Specifically, we affirm that the TRR for Network Transmission customers should include a STIP component of \$3.15 million. We find the Presiding Judge reasonably identified those components of the STIP that benefit PG&E's electric ratepayers, aligning with precedent that requires the exclusion of expenses that do not

⁶²⁶ *Id.* at 76-77.

⁶²⁷ TANC Brief Opposing Exceptions at 92.

⁶²⁸ SWP Brief Opposing Exceptions at 9-10 (citing *Public Service Company of New Mexico*, 813 F.2d at 456).

benefit ratepayers.⁶²⁹ The following STIP categories shall be recovered from Network Transmission customers: (1) emergency responses to 911 calls (5%), (2) downed transmission and distribution wires (5%), (3) duration of electric outages (10%), and (4) safety (10.61%, or 66.3% of 16%). We also affirm the Initial Decision's directive for PG&E to reduce the capitalization factor from 35.74 to 35.24% of STIP costs allocated to Network Transmission. This value is supported by 2015 data, which was the most current data available when the TO18 rate case was filed.⁶³⁰ The revised capitalization factor reduces the forecasted allocation of STIP costs to Network Transmission by \$1.721 million, resulting in a TRR for Network Transmission Customers of \$3.15 million. Accordingly, we affirm the Presiding Judge's STIP allocation of \$3.15 million to Network Transmission customers, which represents a reduction of approximately \$3.6 million from what PG&E proposed.

J. Sales Forecast

240. PG&E derived its stated Network Transmission rate for 2017 by dividing its projected cost of service by its projected load, of which its sales forecast is a part. Thus, PG&E's stated rate will vary inversely with the size of its projected load. PG&E projected that it will sell 81,679 gigawatt-hours (GWh) of electric energy in 2017, which would constitute a drop of 4.4% from its 2015 sales.⁶³¹

1. Initial Decision

241. The Presiding Judge found that PG&E failed to satisfy the first prong of the *Chatham* test, finding flaws in the chain of reasoning it used to support its forecast methodology.⁶³² The Presiding Judge noted that PG&E's witness used "time series regression" analyses to forecast sales for each of the company's major customer classes,⁶³³ and then adjusts the results of these time series regression forecasts to account

⁶²⁹ See, e.g., *Public Service Company of New Mexico*, 813 F.2d at 456.

⁶³⁰ See Initial Decision, 165 FERC ¶ 63,001 at P 863.

⁶³¹ Initial Decision, 165 FERC ¶ 63,001 at PP 865-866 (citing Ex. PGE-0015 (Testimony of Sam Wray) at 1:7-9 and Ex. PGE-0061 (errata), showing Ex. PGE-0015 at 10, tbl. PGE-0015-2).

⁶³² *Id.* P 884.

⁶³³ *Id.* PP 867-868 (citing Ex. S-0019 (Testimony of Dr. C. Shelley Norman) at 7:19-8:4).

for the impacts of “regulatory and legislative policies and goals.”⁶³⁴ The Presiding Judge found that PG&E’s witness’ description of his process would have satisfied *Chatham*’s chain-of-reasoning requirement absent any “countervailing information” on the record; however, the Presiding Judge explained that the record in this case contains contrary evidence provided by Trial Staff witness, who disputed PG&E’s methodology.⁶³⁵ The Presiding Judge determined that Trial Staff’s witness’ method of basing Net Adjustments on the monthly average of the impacts over the past three years, though not perfect, would better reflect the model’s forecast than the method outlined by PG&E, which treats the impacts occurring over the span of the study’s entire period equally.⁶³⁶ The Presiding Judge found that PG&E’s rebuttal to Trial Staff’s concerns to be unpersuasive because, instead of defending his model, he merely claimed that his regression model used all of the data gathered during the study period.⁶³⁷ The Presiding Judge concluded that Trial Staff’s witness’ findings exposed the flaws in PG&E’s chain of reasoning used to support its methodology, thereby failing to satisfy prong one of the *Chatham* test.⁶³⁸

242. The Presiding Judge found that PG&E also failed to satisfy the second prong of the *Chatham* test, explaining that in addition to historically over-forecasting its cost of service, PG&E has historically under-forecasted its sales, resulting in higher rates for a given revenue requirement.⁶³⁹ In reaching this conclusion, the Presiding Judge relied on the evidence present by witnesses for Trial Staff and SWP, demonstrating that PG&E has under-forecast its future retail sales for eight of the past nine years, resulting in an average under-forecast of 302 GWh.⁶⁴⁰ According to the Initial Decision, these witnesses also noted that removing 2009 from the calculation, an extreme outlier resulting from a deep and unexpected recession, would cause the average annual under-forecast for the eight year period to double to 609 GWh.⁶⁴¹ Due to PG&E’s “sound argument” for the inclusion of 2016 and his failure to rebut SWP’s efforts to exclude year 2009, the Presiding Judge found that the comparison should exclude year 2009 and include year

⁶³⁴ *Id.* P 869 (citing Ex. PGE-0015 at 5:2-9).

⁶³⁵ *Id.* PP 874-876, 880 (citing Ex. S-0019 at 11:24-12:4).

⁶³⁶ *Id.* P 883.

⁶³⁷ *Id.*

⁶³⁸ *Id.* P 884.

⁶³⁹ *Id.* P 885.

⁶⁴⁰ *Id.* P 886 (citing Ex. SWP-0001 at 41:17-19 and Ex. S-0019 at 5:12-14).

⁶⁴¹ *Id.* (citing Ex. SWP-001 at 43:1-7).

2016.⁶⁴² Additionally, the Presiding Judge found that the annual average disparity between PG&E's forecasted and actual sales over a four year period was double the disparity that was calculated by the naïve forecast, a validation tool which assumes that all years are alike.⁶⁴³ The Presiding Judge also found that PG&E's witness' attempts to restore the credibility of PG&E's forecasting and discredit Trial Staff's witness' naïve forecast comparison to be unpersuasive.⁶⁴⁴ The Presiding Judge noted that PG&E's failure to sufficiently address weather variations contributed to the inaccuracy of its forecasts.⁶⁴⁵ The Presiding Judge found that the large discrepancy between PG&E's sales forecasts and those presented by Trial Staff's witness calculated using the naïve forecast further demonstrate the unreliability of PG&E's methodology because the randomness of the naïve forecast was substantially more accurate than PG&E's.⁶⁴⁶

243. The Presiding Judge ultimately determined that the defects in PG&E's forecast methodology warrant a remedy and noted that the proposals of both SWP and Trial Staff were worth considering.⁶⁴⁷ The Presiding Judge found that SWP's proposed remedy shared the same obstacles as those proposed by other participants seeking payment by PG&E for their historic forecasting errors.⁶⁴⁸ The Presiding Judge found Trial Staff's method was plausible and well documented, and its witness' adjustments to PG&E's method were appropriate.⁶⁴⁹ The Presiding Judge examined Trial Staff's proposal explaining that it would use the average of the three most recent years of monthly measurement of the impact of customer use of Photovoltaic generation (PV) on PG&E sales to determine the Net Adjustment for PV to better reflect recent trends,⁶⁵⁰ reduce the

⁶⁴² *Id.* P 891.

⁶⁴³ *Id.* P 887 (citing Ex. S-0019 at 6:3-5, 7:6-17).

⁶⁴⁴ *Id.* PP 892-894.

⁶⁴⁵ *Id.* P 893.

⁶⁴⁶ *Id.* P 892.

⁶⁴⁷ *Id.* P 896.

⁶⁴⁸ *Id.* P 899.

⁶⁴⁹ *Id.* P 915.

⁶⁵⁰ *Id.* P 903.

sales forecast to account for PV,⁶⁵¹ eliminate the adjustment to Fuel Cell and Other,⁶⁵² and include a Gross Adjustment to the regression forecast to account for recent policy changes that encourage a more aggressive implementation of Conservation and Energy Efficiency (EE).⁶⁵³ According to the Initial Decision, Trial Staff's witness calculated that PG&E has under-forecast its sales by 173.082 GWh.⁶⁵⁴ The Presiding Judge thus determined that in order to make its sales forecast just and reasonable, PG&E must increase its forecast by 173.082 GWh to account for EE, Distributed Generation (DG), and Electric Vehicles (EV).⁶⁵⁵

244. Next, the Presiding Judge addressed the justness and reasonableness of PG&E's proposed forecast for its Helms Pumped Storage Project (Helms) load. The Presiding Judge explained that PG&E's Helms project works by pumping water to an upper reservoir when prices are low and releasing that water to a lower reservoir to generate electricity when prices are high consumes electric power and contributes to PG&E's gross load.⁶⁵⁶ According to the Initial Decision, PG&E employs a model called PLEXOS to forecast its Helms pumping load which purports to forecast circumstances in which it would be economically advantageous to pump.⁶⁵⁷ The Initial Decision states that PLEXOS provided a forecast for 2017 that all participants agree is too high. The Presiding Judge explains that PG&E attributes the inaccuracy of the forecast to two factors: (1) the model does not take into account certain transmission constraints and congestion that occur on PG&E's system; and (2) PG&E originally ran its PLEXOS model based on the assumption that all three of the Helms pumps would run at the same time, though that rarely occurs.⁶⁵⁸

245. After examining testimony by expert witnesses, the Presiding Judge ultimately concluded that PG&E's forecast for the Helms pumping was flawed, SWP's witness'

⁶⁵¹ *Id.*

⁶⁵² *Id.* P 907.

⁶⁵³ *Id.* P 909.

⁶⁵⁴ *Id.* P 913.

⁶⁵⁵ *Id.* P 915.

⁶⁵⁶ *Id.* P 916 (citing Ex. SWP-0001 at 47:11-16 (citing Ex. PGE-0002 (Testimony of PG&E Witness) at 23:5-8).

⁶⁵⁷ *Id.* P 917 (citing Ex. S-0020 (Testimony of Trial Staff Witness) at 8-9).

⁶⁵⁸ *Id.* P 918 (citing Ex. SWP-0038 (Testimony) at 1-2).

alternative load forecast was a reasonable approach, and that PG&E must make adjustments to its forecast of gross load for it to be just and reasonable.⁶⁵⁹ The Presiding Judge also noted that PG&E converts forecasted sales to forecasted gross load by adding losses of power that are expected to occur between transmission and distribution, and accounts for these anticipated losses by multiplying its forecasted sales by a factor of 1.058707.⁶⁶⁰

2. Briefs on Exceptions

246. PG&E contends that the Initial Decision goes against the Commission's accepted practice of allowing forecasts to be used to set rates so long as those forecasts were reasonable when made.⁶⁶¹ PG&E notes that while the Initial Decision found that PG&E's witness description would satisfy *Chatham*'s chain-of-reasoning requirement absent any countervailing information on the record, PG&E criticized the Initial Decision for continuing to look for "contrary evidence," despite PG&E's claim that its method was reasonable when made.⁶⁶² PG&E also states that the "contrary evidence" mounted against its forecasts was a mere disagreement, and that the Initial Decision incorrectly disposed of its witness' rebuttal to this evidence.⁶⁶³

247. PG&E claims that the Initial Decision was wrong when it stated that its witness did not deny that his regression model gave disproportionate weight to the impacts of the relevant technologies and practices on PG&E's sales over the past few years.⁶⁶⁴ PG&E asserts that its witness was clear when he testified that PG&E's regression-based forecast does not only capture the most recent trends.⁶⁶⁵ PG&E also claims that the Initial Decision's determination that Trial Staff's witness' testimony demonstrated flaws in PG&E's chain of reasoning was unsupported by the record and amounts to nothing more than a slight difference in opinion.⁶⁶⁶ PG&E asserts that this does not render its witness'

⁶⁵⁹ *Id.* PP 919-933.

⁶⁶⁰ *Id.* P 934.

⁶⁶¹ PG&E Brief on Exceptions at 76.

⁶⁶² *Id.*

⁶⁶³ *Id.*

⁶⁶⁴ *Id.* at 77.

⁶⁶⁵ *Id.*

⁶⁶⁶ *Id.*

forecast unreasonable.⁶⁶⁷ PG&E also notes misunderstandings may have led to differences in opinion, and cites Trial Staff's witness' misunderstanding of some of the information she used to form her opinion on behind-the-meter fuel cell technology.⁶⁶⁸

248. PG&E also objects to the Initial Decision's treatment of its historical sales forecasting performance.⁶⁶⁹ PG&E asserts that using historical average temperatures to forecast future temperatures is standard practice, and that its use of weather-adjusted results has allowed them to maintain a strong historical forecast performance.⁶⁷⁰ PG&E concludes that there was no valid reason for the Initial Decision to throw out its forecast in favor of the forecast outlined by Trial Staff's witness because she failed to show that her adjustments would be any more accurate than PG&E's approach.⁶⁷¹

249. PG&E contends that the Initial Decision treated its forecast for Helms pumping inconsistently with its treatment of the other forecast issues addressed in this proceeding, which culminated in a recommendation by the Initial Decision that is both unjustified and unsupported by the record.⁶⁷² PG&E criticizes the Initial Decision's reliance on actual costs rather than heeding the suggestion of Trial Staff's witness to look at the most recent twelve months of actual Helms pumping data to adjust PG&E's forecast.⁶⁷³ Instead, PG&E contends that the Initial Decision ignored the testimony of its expert witness, and adopted a different forecast proposed by the witness for SWP, which relied exclusively on a PLEXOS model that was not adjusted for known problems with that model.⁶⁷⁴ PG&E claims that this reliance led to a forecast that increased the Helms pumping load

⁶⁶⁷ *Id.*

⁶⁶⁸ *Id.*

⁶⁶⁹ *Id.*

⁶⁷⁰ *Id.* at 78.

⁶⁷¹ *Id.*

⁶⁷² *Id.* at 79.

⁶⁷³ *Id.*

⁶⁷⁴ *Id.*

considerably and decreased PG&E's recovery.⁶⁷⁵ PG&E concludes that the test for this issue should be whether the forecast was reasonable when made.⁶⁷⁶

3. Briefs Opposing Exceptions

250. SWP contends there is sufficient evidence to show that PG&E's forecast was not reasonable at the time it was made.⁶⁷⁷ It states that the testimony provided by its expert, including the naïve forecast, demonstrates the poor job PG&E has done of forecasting its gross load.⁶⁷⁸ SWP notes that an analysis of historical data, where PG&E has under-forecast its sales in eight out of its ten most recent rate cases, supports this conclusion.⁶⁷⁹ Additionally, SWP asserts that PG&E has a structural incentive to under-forecast because they generate more money when they do so.⁶⁸⁰ SWP next asserts that the Initial Decision's use of the model that maintains a two-pump constraint produces a just and reasonable forecast and should be affirmed.⁶⁸¹ SWP also criticizes PG&E's decision to run its model simulation without any constraint on the concurrent operation of the three pumps and make ad hoc adjustments to account for the fact that only two pumps were generally in operation at a time.⁶⁸²

251. Trial Staff states that the Initial Decision was correct in finding that PG&E's sales forecast was not just and reasonable, and that PG&E's sales forecast should be increased by 173.082 GWh in order to render it just and reasonable.⁶⁸³ Trial Staff contends that the Initial Decision's acceptance of its recommended adjustment to PG&E's sales forecast was fully supported by the record because Trial Staff's witness showed that PG&E's

⁶⁷⁵ *Id.*

⁶⁷⁶ *Id.* at 80.

⁶⁷⁷ SWP Brief Opposing Exceptions at 14.

⁶⁷⁸ *Id.* at 12.

⁶⁷⁹ *Id.* at 12-13.

⁶⁸⁰ *Id.* at 13.

⁶⁸¹ *Id.* at 15.

⁶⁸² *Id.*

⁶⁸³ Trial Staff Brief Opposing Exceptions at 42 (citing Initial Decision, 165 FERC ¶ 63,001 at P 915).

methods used to adjust its forecast were unreasonable when they were made.⁶⁸⁴ Trial Staff asserts that PG&E mischaracterized the contrary evidence presented to the Presiding Judge by arguing that it was a mere disagreement.⁶⁸⁵ Trial Staff also agrees with the Initial Decision's finding that Trial Staff's witness' method of adjusting for impacts over the past 36-month period would better reflect the model's forecast than the method outlined by PG&E's witness, which treats the impacts occurring over the study's 153 months equally.⁶⁸⁶ Trial Staff also states its agreement with the Initial Decision's identification of PG&E's flaw in its chain of reasoning, and notes that PG&E's witness' failure to deny that his regression model gives greater weight to the impacts of the relevant technologies and practices on PG&E's sales during recent years is not inconsistent with PG&E's rebuttal that his testimony does not only capture the most recent trends.⁶⁸⁷ Trial Staff suggests that PG&E incorrectly stated that Trial Staff's witness misunderstood the information she used to inform her opinion about behind-the-meter fuel cell technology.⁶⁸⁸ Trial Staff concludes that this statement made by PG&E on Trial Staff's witness' conclusions goes beyond anything that was initially raised by PG&E's witness and that nothing in the record hints that the change cited by PG&E constitutes a policy shift of the type PG&E's witness sought to account for in his policy adjustments.⁶⁸⁹

4. Commission Determination

252. We affirm the Initial Decision on this issue. The Presiding Judge carefully considered several different forecast models presented by PG&E's witnesses, Trial Staff's witness, and SWP's witness, as well as rebuttal testimony, and determined that PG&E's sale forecast was not just and reasonable absent the adjustments described in the Initial Decision.⁶⁹⁰ The Presiding Judge concluded that, based on the record evidence, PG&E under-forecasted its sales for eight out of the ten years under consideration, and

⁶⁸⁴ *Id.* at 43 (citing Initial Decision, 165 FERC ¶ 63,001 at PP 877-880, 883, 900).

⁶⁸⁵ *Id.* (citing PG&E Brief on Exceptions at 76).

⁶⁸⁶ *Id.* at 42 (citing Initial Decision, 165 FERC ¶ 63,001 at P 883).

⁶⁸⁷ *Id.* at 44 (citing Initial Decision, 165 FERC ¶ 63,001 at P 883).

⁶⁸⁸ *Id.*

⁶⁸⁹ *Id.* at 45.

⁶⁹⁰ Initial Decision, 165 FERC ¶ 63,001 at PP 867-933.

under-forecasted sales over the 10-year period by an annual average of 404 GWh.⁶⁹¹ The Presiding Judge thus determined that these defects in PG&E's witness' analysis warranted a remedy.⁶⁹² Next, by carefully comparing the methodologies in the proposals set forth by Trial Staff's and SWP's witnesses, the Presiding Judge also found the method set forth by Trial Staff's witness to be both plausible and well documented and her adjustments to PG&E's method to be appropriate.⁶⁹³ We agree with the Presiding Judge's conclusions. The record shows that PG&E under-forecasted its sales for eight out of the ten years under consideration, and under-forecasted sales over the 10-year period by an annual average of 404 GWh.⁶⁹⁴

253. As for the forecast for Helms pumping load, the Presiding Judge evaluated both Trial Staff's and SWP's alternative load forecasts, as well as PG&E's rebuttal, and chose SWP's model as a reasonable approach.⁶⁹⁵ As the Presiding Judge noted, PG&E also revised its modeling such that it effectively adopted the approach that SWP's witness took in developing his alternative forecast.⁶⁹⁶ We again find that the Presiding Judge carefully examined the record evidence and made a reasoned decision on this issue. Accordingly, we affirm the Presiding Judge that PG&E must adjust its sales forecast in accordance with the alternative models to ensure that it is just and reasonable.

254. We reject PG&E's argument that the Presiding Judge should have accepted its sales forecast outright because it was reasonable when made. To determine whether PG&E's forecast is reasonable, the Presiding Judge correctly applied the two-prong *Chatham* test and concluded, based on his review of the record evidence, that PG&E failed both prongs and determined that PG&E has failed to meet its requirements.⁶⁹⁷ We also reject PG&E's assertion that the alternative model forecasts represent a mere difference in opinion. The record shows that the Presiding Judge considered multiple forecasts, their methodologies, and the drawbacks and strengths of each of the forecasts before making a final decision on which model to apply. The Presiding Judge's

⁶⁹¹ *Id.* P 892 (citing Ex. PGE-0049 (Rebuttal Testimony of Sam Wray) at 9; and Ex. SWP-0008 (Testimony of David Marcus) at 1).

⁶⁹² *Id.* P 896.

⁶⁹³ *Id.* PP 867-915

⁶⁹⁴ Ex. PGE-0049 at 8 and Ex. SWP-0008 at 1.

⁶⁹⁵ Initial Decision, 165 FERC ¶ 63,001 at PP 916-933.

⁶⁹⁶ *Id.* P 925.

⁶⁹⁷ *Id.* PP 884, 895.

conclusions that PG&E's methodology was flawed and that PG&E's has historically under-forecasted its sales were reasonable and supported by record evidence. We find no reason to disturb this reasoned analysis. We therefore affirm the Presiding Judge's finding in regard to PG&E's sales forecast and direct PG&E to adjust it in accordance with this finding.

K. Miscellaneous Issues

1. Inclusion of Certain Non-Capital Items

a. Habitat Conservation Plan Costs

255. PG&E proposed to include in Account 186, Miscellaneous Deferred Debits, \$20.193 million in costs association with its Habitation Conservation Plan as a component of rate base during the period in which those costs are recorded. PG&E included those costs in its calculation of Working Capital.

i. Initial Decision

256. The Presiding Judge found that PG&E's placement of its Habitation Conservation Plan costs in its rate base while recording these costs in Account 186 was not just and reasonable.⁶⁹⁸ The Presiding Judge noted that PG&E incurs two types of Habitation Conservation Plan costs: (1) the costs needed to develop the Habitation Conservation Plan before the Incidental Take Permit is received; and (2) the funds paid to a third-party mitigation land manager.⁶⁹⁹ According to the Initial Decision, the costs needed to develop the Habitation Conservation Plan are initially recorded in Account 186,⁷⁰⁰ but PG&E moves these costs into Account 303, Miscellaneous Intangible Plant, once they receive the Incidental Take Permit,⁷⁰¹ while the funds paid to the mitigation land manager remain in Account 186 until they are allocated to specific projects.⁷⁰² The Presiding Judge determined that, while it was appropriate for PG&E to record its Habitation Conservation Plan costs in Account 186, it was not appropriate for PG&E to include

⁶⁹⁸ *Id.* P 950.

⁶⁹⁹ *Id.* P 941 (citing Ex. CIT-0017 (Testimony of Terry Myers) at 15:14-17 and Ex. CIT-0030 at 2).

⁷⁰⁰ *Id.* P 942 (citing Ex. CIT-0017 at 15:11-14).

⁷⁰¹ *Id.*

⁷⁰² *Id.* (citing Ex. CIT-0030 at 2).

those costs in the rate base while those costs remained in the account.⁷⁰³ The Presiding Judge found that the used and useful standard, which states that “an asset may be included in a utility’s rate base only when the item is used and useful in providing service,” was not met by either of PG&E’s two types of Habitation Conservation Plan costs.⁷⁰⁴ The Presiding Judge further elaborated that the first category of Habitation Conservation Plan costs, used to develop the Habitation Conservation Plan, is not used and useful until PG&E receives the Incidental Take Permit, and the second category of the Habitation Conservation Plan costs, which goes to a mitigation land manager, does not benefit ratepayers while in Account 186 because these costs are not associated with any project.⁷⁰⁵ The Presiding Judge determined that prohibiting PG&E from including these costs in its rate base while they remain in Account 186 is not unfair to PG&E because they may move the costs of developing the Habitation Conservation Plan into Account 303 and collect them through rates once it receives the ITP,⁷⁰⁶ recover costs once the funds paid to the land mitigation manager are allocated to a project and the project goes into service,⁷⁰⁷ and recover funds allocated to maintenance projects through their TRR.⁷⁰⁸

257. Additionally, the Presiding Judge noted that, while the used and useful standard of ratemaking is only one of several tools available to the Commission, PG&E did not put forth any information that would suggest that the Commission should have employed another ratemaking standard.⁷⁰⁹ The Presiding Judge also found that PG&E’s two central justifications for including the costs in the rate base—that the costs must be incurred to comply with environment mandates and it would benefit ratepayers by reducing the cost of compliance—are mitigated by the fact that PG&E will eventually recover these costs through appropriate channels. The Presiding Judge concluded that PG&E’s placement of its HPC costs in its rate base while they are recorded in Account 186 is not just and

⁷⁰³ *Id.* P 944 (citing Ex. CIT-0017 at 18:1-7, 21:1-17).

⁷⁰⁴ *Id.* PP 944-945 (citing *New England Power Co.*, 42 FERC ¶ 61,016 (1988) and *NEPCO*, 668 F.2d 1327).

⁷⁰⁵ *Id.* P 945 (citing Ex. S-0023 at 23:4-10).

⁷⁰⁶ *Id.* P 946 (citing Ex. CIT-0030 at 2-3).

⁷⁰⁷ *Id.* (citing Ex. TNC-0018 at 10:8-11:5).

⁷⁰⁸ *Id.* (citing Ex. CIT-0017 at 16:22-17:3).

⁷⁰⁹ *Id.* P 949 (citing *New England Power Co.*, 42 FERC at 61,078).

reasonable; therefore, the Presiding Judge concluded that PG&E must account for these misplaced costs by removing \$20.193 million from its rate base.⁷¹⁰

ii. Brief on Exceptions

258. In its brief on exceptions, PG&E reiterates several points of its witness' testimony, including that Habitation Conservation Plan costs allow PG&E to reduce environmental mitigation costs⁷¹¹ and to provide pre-negotiated compensatory mitigation.⁷¹² PG&E states that it recognizes that not all of the Habitation Conservation Plan costs should be included in TO18 Period II due to their lack of impact on servicing transmission customers.⁷¹³ PG&E also points to the Initial Decision's acknowledgement that the used and useful standard is "only one of several permissible tools available to the Commission."⁷¹⁴ PG&E asserts that it does, however, meet the prudence standard also cited in the Initial Decision.⁷¹⁵ Finally, PG&E contends that the Initial Decision incorrectly stated that PG&E will eventually recover their costs.⁷¹⁶ PG&E states that it would be unable to recover a return on investment because it would be prevented from investing in other company endeavors while the money was tied up in the initial stages of the Habitation Conservation Plan process.⁷¹⁷

iii. Briefs Opposing Exceptions

259. Six Cities asserts that it was inappropriate for PG&E to include the average balance of its Habitation Conservation Plan costs in its calculation of Working Capital.⁷¹⁸ Six Cities contends that PG&E's claim that the Initial Decision should have employed the

⁷¹⁰ *Id.* P 950.

⁷¹¹ PG&E Brief on Exceptions at 80 (citing Ex. PGE-0042 (Testimony of PG&E Witness) at 13 (errata)).

⁷¹² *Id.* (citing Ex. PGE-0042 at 13).

⁷¹³ *Id.* at 81.

⁷¹⁴ *Id.* (citing Initial Decision, 165 FERC ¶ 63,001 at P 949).

⁷¹⁵ *Id.* (citing *New England Power Co.*, 42 FERC at 61,078).

⁷¹⁶ *Id.* (citing Initial Decision, 165 FERC ¶ 63,001 at P 949).

⁷¹⁷ *Id.*

⁷¹⁸ Six Cities Brief Opposing Exceptions at 61.

prudence standard instead of the used and useful standard to determine the appropriateness of PG&E's inclusion of the Habitation Conservation Plan costs in the rate base fails to address the relevant issue in this case.⁷¹⁹ Six Cities also notes its agreement with the Initial Decision's determination that PG&E's ratemaking treatment of Habitation Conservation Plan costs in the same manner as prepayments was inappropriate.⁷²⁰ Six Cities asserts that, because Habitation Conservation Plan costs do not share the same characteristics as prepayments, they should not be treated like them as PG&E does by including them in the Working Capital inclusion.⁷²¹ Six Cities further explains that while it was proper for the Habitation Conservation Plan costs to be included in Account 186, they should not be included in Working Capital because they are not used and useful, and their final disposition is uncertain.⁷²²

260. Trial Staff agrees with the Initial Decision's finding that PG&E's inclusion of Habitation Conservation Plan costs in its rate base while these costs were also recorded in Account 186 was not just and reasonable.⁷²³ Trial Staff also agrees with the Initial Decision's determination that PG&E failed to provide any evidence that would render the use of an alternative ratemaking standard necessary.⁷²⁴ Trial Staff contends that the relevant issue is whether PG&E can incorporate Habitation Conservation Plan costs into its base rate, not, as PG&E contends, whether the Habitation Conservation Plan costs are prudent.⁷²⁵ Finally, Trial Staff states that the Initial Decision was correct in finding that PG&E's justifications for incorporating the Habitation Conservation Plan costs into the rate base, including that it would incur costs to meet environmental standards and that it would be beneficial to ratepayers, were insufficient to rebut the contention that they were not used and useful to ratepayers.⁷²⁶ Trial Staff does, however, sympathize with PG&E's claim that it will not eventually have the opportunity to recover the relevant costs through

⁷¹⁹ *Id.* at 62.

⁷²⁰ *Id.* at 63.

⁷²¹ *Id.* at 64.

⁷²² *Id.* at 64 (citing Ex. CIT-0017 at 20:17-21).

⁷²³ Trial Staff Brief Opposing Exceptions at 45-46 (citing Initial Decision, 165 FERC ¶ 63,001 at P 950).

⁷²⁴ *Id.* at 46 (citing Initial Decision, 165 FERC ¶ 63,001 at P 949).

⁷²⁵ *Id.*

⁷²⁶ *Id.* at 46-47.

appropriate channels.⁷²⁷ For this reason, Trial Staff contends that it would be fair to allow PG&E to accrue and capitalize the financing costs associated with its Habitation Conservation Plan investments because it would allow PG&E to recover the costs when the final placement of the costs is known.⁷²⁸

iv. Commission Determination

261. We affirm the Presiding Judge's finding on this issue. As to PG&E's argument that the inclusion of the Habitation Conservation Plan costs in its rate base should have been evaluated under a different standard, we refer back to paragraph 949 of the Initial Decision, which addressed this particular argument:

While the "used and useful" standard of ratemaking is only one of several permissible tools available to the Commission, PG&E has provided no evidence that suggests that the Commission needs to consider another ratemaking standard. PG&E's only justifications for including the costs in rate base are that the expenditures connected with the [Habitation Conservation Plan] (1) must be incurred to comply with environmental requirements and (2) will benefit ratepayers by reducing the costs of such compliance. While both contentions may be true, they do not rebut the contention that while the [Habitation Conservation Plan] costs are in Account 186, they are not connected with any project that is used and useful to ratepayers. Moreover, both considerations are mitigated by the fact that PG&E will eventually recover these costs through appropriate channels. (*internal footnotes omitted*)

We find that the Presiding Judge's analysis is reasonable and agree with his conclusions. We therefore direct PG&E to remove \$20.193 million from its rate base on compliance, consistent with the Presiding Judge's findings. However, we will allow PG&E to accrue and capitalize the financing costs associated with its Habitation Conservation Plan investments, which would allow PG&E to recover the costs when the final project-specific allocation of the costs is known.

b. Working Cash

262. PG&E proposed to include \$25.638 million attributable to cash working capital in rate base.⁷²⁹ PG&E explained that the working capital is necessary to maintain adequate

⁷²⁷ *Id.* at 47 (citing PG&E Brief on Exceptions at 81).

⁷²⁸ *Id.*

⁷²⁹ Ex. PG&E-0010 at 30:5-26 and 32:7.

levels of supplies, to meet required prepayments, and to meet ongoing cash disbursements that are made during a different period of time than related receipts for utility services rendered. PG&E explained that cash working capital is a component of working capital, and reflects the extent to which day-to-day cash from operational utility service is received earlier or later than the disbursements necessary to provide the service.⁷³⁰ As explained by Trial Staff, current accounts receivable and payable are forms of incidental short-term financing provided by one party to another: The party that receives a service benefits from the time value of the payment owed between the party's receipt of the service and its payment for the service. A current receivable on PG&E's books is an item for which PG&E's shareholders are providing short-term financing to another entity. Conversely, a current payable on PG&E's books is an item for which another entity is providing PG&E's shareholders short-term financing. PG&E, like most companies, always maintains an outstanding receivables balance and an outstanding payables balance. By maintaining the former balance, the company provides short-term financing. The financing costs associated with the time lag between when the good or service is provided and when payment is actually collected must be borne by somebody. Placing this financing cost in rate base under the heading cash working capital passes that cost on to ratepayers.⁷³¹

i. Initial Decision

263. The Presiding Judge noted that for calculating cash working capital, the Commission recognizes the formula approach for electric utilities and the lead-lag approach for all utilities; however, it does not use the balance sheet approach for ratemaking.⁷³² The Presiding Judge relied on Trial Staff's witness' assertion that PG&E's purported lag study approach is deficient because: (1) the data used by the company is stale; (2) PG&E uses a balance sheet approach to calculate the revenue portion of the lead-lag study; and (3) the company has failed to create a revenue lag study that applies specifically to the Network Transmission function.⁷³³ The Presiding Judge found the rebuttal by PG&E's witness unpersuasive.⁷³⁴ According to the Initial Decision, PG&E's witness explained that PG&E used 2014 as the base year in its lead-lag study because that was what they used for the most recent general rate case it filed with CPUC,

⁷³⁰ PG&E Initial Brief at 76; Ex. PGE-0042 at 21.

⁷³¹ Ex. S-0023 at 25:19-26:16; Ex. S-0026 at 57.

⁷³² *Id.* P 955.

⁷³³ *Id.* P 956 (citing Ex. S-0023 at 31:1-8).

⁷³⁴ *Id.* P 965.

and the study is only created every three years because it takes a lot of effort to create,⁷³⁵ and there are only minor changes in working cash flow over this short of a period of time.⁷³⁶ The Presiding Judge concluded that Trial Staff's witness' assertions and PG&E's witness' rebuttal make clear that PG&E has derived the lead-lag study in the current case from a company-wide lead-lag study that it prepared for a recent general rate case before CPUC, which are litigated every three years.⁷³⁷ The Presiding Judge stated that the Commission requires the most recent base year data available to be used, that the 2015 data should have been as accessible as the 2014 data, and that PG&E failed to cite any cases where the Commission suggested that it would accept older data based on the size of the variability between the data used and more recent data.⁷³⁸ Thus, the Presiding Judge determined that what PG&E considered to be its "lead-lag" study was deficient.

264. The Presiding Judge also determined that PG&E failed to demonstrate that creating a separate lead-lag study solely for Network Transmission would be burdensome, and PG&E failed to quantify the burden that it claims would result from developing a lead-lag study two years in a row.⁷³⁹ The Presiding Judge ultimately rejected PG&E's method of determining the revenue lag component of the lead-lag study, and noted that the method's compliance with CPUC guidelines does not justify its implementation in Commission proceedings.⁷⁴⁰ Due to the deficiency of PG&E's lead-lag study, the Presiding Judge determined that PG&E must remove \$25.638 million attributable to its cash working capital from its rate base.⁷⁴¹

ii. Brief On Exceptions

265. PG&E asserts that it was correct in including the working cash rate in its rate base and that the working cash calculation it used in its TO18 filing contained the proper components.⁷⁴² It also claims that a sound approach was used to calculate their revenue

⁷³⁵ *Id.* PP 962-963 (citing Ex. PGE-0042 at 21:23-27).

⁷³⁶ *Id.* P 964 (citing Ex. PGE-0042 at 21:30-22:5).

⁷³⁷ *Id.* P 962.

⁷³⁸ *Id.* P 965.

⁷³⁹ *Id.* P 966.

⁷⁴⁰ *Id.* P 968.

⁷⁴¹ *Id.* P 973.

⁷⁴² PG&E Brief on Exceptions at 82 (citing Ex. PGE-0042 at 21).

lag.⁷⁴³ PG&E disagrees with the Initial Decision's determination that it should have developed a separate lead-lag study solely for Network Transmission.⁷⁴⁴ PG&E contends that its current process for calculating the lead-lag study results in a more sensible use of the company's resources, and argues that the requirement suggested in the Initial Decision would result in an excessive cost increase to Network Transmission customers.⁷⁴⁵ PG&E claims that it should not be denied the entire working cash balance because the Presiding Judge finds it unacceptable.⁷⁴⁶ Though PG&E asserts that the calculation as filed is reasonable, if the Commission disagrees, it requests that the 1/8th O&M calculation as described in the rebuttal testimony be permitted.⁷⁴⁷ Finally, PG&E asks that, if the Commission accepts the Initial Decision's recommendation to remove the entire working cash balance from the rate base calculation, PG&E should not have to make the Habitation Conservation Plan adjustment as outlined in the Initial Decision.⁷⁴⁸

iii. Brief Opposing Exceptions

266. Trial Staff asserts that the Initial Decision was correct in finding that PG&E should remove cash working capital from its base rate and agrees with the Presiding Judge's decision to reject PG&E's lead-lag study.⁷⁴⁹ Trial Staff contends that PG&E's claim, that requiring PG&E to create a separate lead-lag study solely for Network Transmission customers would be too costly and entail too much effort, is baseless and violates many tenants of cost of service ratemaking.⁷⁵⁰ Trial Staff also claims that PG&E's calculation is inconsistent with the established practice of the Commission.⁷⁵¹ Trial Staff reiterates their witness' testimony, which states that PG&E's lead-lag study was not fully developed because: (1) PG&E's use of stale data was not justified; (2)

⁷⁴³ *Id.* at 82 (citing Initial Decision, 165 FERC ¶ 63,001 at P 968).

⁷⁴⁴ *Id.*

⁷⁴⁵ *Id.* (citing *Golden Spread Elec. Coop., Inc. v. Sw. Pub. Serv. Co.*, 123 FERC ¶ 61,047 (2008) (*Golden Spread*)).

⁷⁴⁶ *Id.* at 83.

⁷⁴⁷ *Id.*

⁷⁴⁸ *Id.*

⁷⁴⁹ Trial Staff Brief Opposing Exceptions at 48.

⁷⁵⁰ *Id.* (citing PG&E Brief on Exceptions at 82).

⁷⁵¹ *Id.*

PG&E's decision to base its revenue lag on daily average amounts of outstanding revenues and billed revenues fails to weigh the outstanding bills and does not factor in the time between when the service is provided and paid for; and (3) PG&E inappropriately derives its revenue lag on a total company basis instead of developing a function-specific revenue lag for its network transmission customers.⁷⁵²

267. Additionally, Trial Staff asserts that PG&E's reliance on *Golden Spread* in its request for the Commission to accept the 1/8th calculation included in PG&E's rebuttal testimony was misplaced because, unlike in *Golden Spread*, PG&E's lead-lag study in the pending proceeding is deficient and provides no basis for the Commission to accept an alternate 45-day convention that would lead to a higher amount of cash working capital allowed in the base rate.⁷⁵³ Finally, Trial Staff notes that the Initial Decision misidentified the cash working capital amount that PG&E needed to remove from its base rate.⁷⁵⁴ Trial Staff claims that the proper reduction should be \$4.647 million, not \$25.638 million, and that only the cash working capital amount should be subtracted from the rate base, not the entirety of working cash.⁷⁵⁵

iv. Commission Determination

268. We agree with the Presiding Judge's determination that PG&E's lead-lag study is deficient. The data used in the lead-lag is from 2014, and we find there may be discrepancies between the cash flow from 2014 and the more recent year. As correctly noted by Trial Staff's witness, the revenue lag based on daily average amounts of outstanding revenues and billed revenues fails to weigh the outstanding bills and does not factor in the time between when the service is provided and when it is paid for.⁷⁵⁶ In addition, we find that PG&E inappropriately derives its revenue lag on a total company basis instead of developing a function-specific revenue lag for its network transmission customers. We therefore affirm the Presiding Judge's finding on this issue.

269. We also deny PG&E's request to accept an alternate calculation of the 1/8th O&M included in PG&E's rebuttal testimony as its working cash flow approximation, as had

⁷⁵² *Id.* at 49.

⁷⁵³ *Id.* at 50.

⁷⁵⁴ *Id.* at 48.

⁷⁵⁵ *Id.* (citing Ex. PGE-0021 at 132, line 16, col. 9).

⁷⁵⁶ Ex. S-0023 at 31:15:20.

been previously done in *Golden Spread*.⁷⁵⁷ We find that PG&E's reliance on *Golden Spread* is misplaced. In that case, the utility filed for a cash working capital allowance based on the 45-day convention and an intervenor attempted to use a lead-lag study to show that the utility had less cash working capital needs than the amount produced by the 45-day convention. The Commission rejected the lead-lag study as unreliable, and therefore accepted the utility's cash working capital as filed.⁷⁵⁸ Here it is PG&E's lead-lag study that is deficient. There is no basis for the Commission to accept the alternate 1/8th O&M calculations that would result in a higher amount of cash working capital allowed in rate base than under the methodology proposed in PG&E's filing.

270. Although we agree with the Presiding Judge that PG&E's lead-lag study is deficient, we reverse the Presiding Judge with respect to the amount of money that PG&E must remove from rate base. As correctly explained by Trial Staff,⁷⁵⁹ the proper reduction should be \$4.647 million, not \$25.638 million, and that only the cash working capital amount should be subtracted from the rate base, not the entirety of working cash. We therefore direct PG&E to remove \$4.647 million from its base rate.

c. Other Receivables

271. PG&E proposed to include \$12.813 million in its working cash under the heading "Other Receivables." PG&E described "Other Receivables" as a "summation of a series of receivables accounts at a total company level that are allocated out to business functions by labor percentages."⁷⁶⁰ These accounts cover revenues due to PG&E for goods or services that the company has provided.⁷⁶¹

i. Initial Decision

272. The Presiding Judge found that PG&E's inclusion of Other Receivables in the rate base was improper for the following reasons: (1) the removal of these costs would lower PG&E's TRR by \$1.244 million;⁷⁶² (2) the receivables included in this item are neither

⁷⁵⁷ 123 FERC ¶ 61,047.

⁷⁵⁸ *Id.* P 104.

⁷⁵⁹ Trial Staff Brief Opposing Exceptions at 48.

⁷⁶⁰ Ex. S-0026 (Responses to Data Request) at 55.

⁷⁶¹ See Initial Decision, 165 FERC ¶ 63,001 at P 974 (citing Ex. PGE-0021 at 132:4 and 133:4; Ex. S-00026 at 55).

⁷⁶² *Id.* P 976 (citing Ex. S-0024 at 31).

owed for Network Transmission Service nor PG&E's Network Transmission customers, but would essentially result in its Network Transmission customers cross-subsidizing the recipients of the goods and services covered by the receivables in question;⁷⁶³ and (3) the inclusion of these costs would augment PG&E's cash working capital calculation by employing a method not approved by the Commission.⁷⁶⁴ The Presiding Judge concluded that PG&E must remove Other Receivables from the rate base to render its rates just and reasonable.⁷⁶⁵

ii. Brief on Exceptions

273. PG&E asserts that the Initial Decision was incorrect in finding that the inclusion of Other Receivables in the cash working capital calculation would result in cross-subsidies.⁷⁶⁶ PG&E notes that its Network Transmission customers do not pay bills at different rates than their other customers, and that PG&E does not pay vendors for Network Transmission needs at different rates than vendors for their other customers.⁷⁶⁷ PG&E concludes that, because there was no evidence of cross-subsidy in the record, there was no basis for the Initial Decision's conclusion.⁷⁶⁸

iii. Brief Opposing Exceptions

274. Trial Staff contends that the Initial Decision correctly found that PG&E should be required to remove \$12.813 million in Other Receivables.⁷⁶⁹ Trial Staff also challenges PG&E's rebuttal that its inclusion of Other Receivables does not result in cross-subsidization.⁷⁷⁰ Trial Staff notes that PG&E fails to support its claim that the Network Transmission Customers do not pay different rates than other customers and that vendors for Network Transmission needs are not paid at different rates than other vendors, with

⁷⁶³ *Id.* P 977 (citing Ex. S-0023 at 26:19-27:7).

⁷⁶⁴ *Id.* P 978 (citing Ex. S-0023 at 27:7-28:12).

⁷⁶⁵ *Id.* P 982.

⁷⁶⁶ PG&E Brief on Exceptions at 84.

⁷⁶⁷ *Id.*

⁷⁶⁸ *Id.*

⁷⁶⁹ Trial Staff Brief Opposing Exceptions at 51 (citing Initial Decision, 165 FERC ¶ 63,001 at P 982).

⁷⁷⁰ *Id.* at 51-52.

any factual basis.⁷⁷¹ Additionally, Trial Staff asserts that cross-subsidization results from allocating these receivables to the Network Transmission rate base that are not explicitly related to the provision of network transmission service, not, as PG&E claims, from the rate which PG&E's different customers pay their bills or that they themselves pay them.⁷⁷² Trial Staff also notes that the only connection between Other Receivables and PG&E's transmission revenue requirements, the revenue from one of the receivables counts as revenue credit against the TRR, is insufficient to justify PG&E's inclusion of Other Receivables in rate base.⁷⁷³ Trial Staff concludes that PG&E's inclusion of this item is essentially a proposal to have its ratepayers pay for the short-term financing that it provides to third parties.⁷⁷⁴

iv. Commission Determination

275. We affirm the Presiding Judge's finding that PG&E should remove \$12.813 million in Other Receivables. We find that the receivables included in this item are not owed for Network Transmission service and are not owed by PG&E's Network Transmission customers. PG&E's inclusion of non-Network Transmission receivables in the Network Transmission portion of Other Receivables is improper because PG&E's customers would be paying the short-term financing costs for invoices owed by other entities for services other than Network Transmission. Accordingly, we reject PG&E's contention that including the receivables at issue is not cross-subsidization. It is irrelevant that the rate applicable to other PG&E customers is not different. The cross-subsidization here is the result of the allocation of these receivables to the Network Transmission rate base that are not specifically related to the provision of network transmission service. We find this cross-subsidization unacceptable and direct PG&E to remove \$12.813 million from Other Receivables.

2. Prepaid Expenses That Should Not be Included in Rate Base

276. On June 29, 2004, PG&E issued a series of pollution control bonds. In this proceeding, PG&E proposed to include in its rate base a premium for insurance it purchased from the Financial Guarantee Insurance Company (FGIC) for those bonds.⁷⁷⁵

⁷⁷¹ *Id.* at 52.

⁷⁷² *Id.*

⁷⁷³ *Id.*

⁷⁷⁴ *Id.*

⁷⁷⁵ Ex. S-0039.

a. Initial Decision

277. The Initial Decision addressed Trial Staff's assertion that PG&E should be required to remove the 2004 pollution control bond premium from its rate base,⁷⁷⁶ and PG&E's rebuttal that the bond premium was a cost of doing business, not a cost to obtain debt financing, and should be included in the rate base.⁷⁷⁷ The Presiding Judge determined that PG&E's payment of the insurance premium was a cost of issuing the bonds and concluded that PG&E must remove the premium from its rate base.⁷⁷⁸

b. Brief on Exceptions

278. PG&E contends that the Initial Decision was incorrect so far as it instructed PG&E to remove the premium for insurance on the pollution control bonds, rejected its witness' testimony, and speculated that payment of the insurance premium was a cost of issuing the bonds without citing to the record.⁷⁷⁹ PG&E reiterates that it considers all relevant pre-payments, adds them together, and appropriately allocates the sum among various lines of business.⁷⁸⁰

c. Brief Opposing Exceptions

279. Trial Staff supports the Initial Decision's finding that PG&E should be required to recalculate its prepayments to remove the bond premium from its rate base.⁷⁸¹ Trial Staff contends that, in contrast to PG&E's assertions, the record shows that the bond premium should not be included in the base rate because it is a cost of issuing the bonds.⁷⁸² Trial Staff also highlights several points made by PG&E's witness, including: PG&E's insurance on the bond premium was a credit enhancement that allowed the company to issue a lower coupon rate, the FGIC on the control bonds cannot be removed unless the bonds are re-issued or redeemed, the bonds were issued using FGIC insurance as a credit

⁷⁷⁶ Initial Decision, 165 FERC ¶ 63,001 at P 993.

⁷⁷⁷ *Id.* P 994.

⁷⁷⁸ *Id.* P 995.

⁷⁷⁹ PG&E Brief on Exceptions at 84.

⁷⁸⁰ *Id.* at 85.

⁷⁸¹ Trial Staff Brief Opposing Exceptions at 52 (citing Initial Decision, 165 FERC ¶ 63,001 at P 995 (citing Ex. S-0023 at 34:2-9, 35:21-23)).

⁷⁸² *Id.* at 53.

enhancement and allowed PG&E to obtain a lower interest rate, and the bond premium was paid on the same day the pollution control bonds were issued.⁷⁸³ Trial Staff concludes that, because the payment of the insurance premium was a cost of issuing the bonds, the cost should be included in the cost of debt calculation used in determining cost of capital and removed from the base rate.⁷⁸⁴

d. Commission Determination

280. We affirm the Initial Decision and direct PG&E to remove the 2004 pollution control bond premium from rate base on compliance. The record shows that PG&E was able to obtain a lower interest rate by issuing the 2004 pollution control Bonds with FGIC insurance as a credit enhancement.⁷⁸⁵ Given that PG&E purchased the FGIC insurance at the same time that it issued the bonds, and made the purchase of the FGIC insurance for the express purpose of obtaining a lower interest rate, the payment of the insurance premium was a cost of issuing the bonds. We therefore find that the 2004 PC bond insurance premium paid to insure PG&E's debt obligations is a cost of acquiring debt and must be reflected in the cost of debt calculation used in determining cost of capital. We conclude that PG&E's proposed inclusion of the 2004 pollution control bond insurance premium in rate base is inappropriate.

3. Forecast of Non-Tariffed New Products and Services (NP&S) Expenses and Revenue

281. PG&E's Non-Tariffed New Products and Services (NP&S) are secondary products and services that the utility offers through its Network Transmission assets including: "(1) leases of transmission tower facility rights for wireless antennae affixtures (Wireless); (2) leases of space on transmission facilities for telecommunication usages (Wire-Line); and (3) transmission maintenance and consulting (Maintenance and Consulting)."⁷⁸⁶ For 2017, PG&E forecasted total net revenues of \$24.652 million,

⁷⁸³ *Id.*

⁷⁸⁴ *Id.*

⁷⁸⁵ Ex. S-0039.

⁷⁸⁶ Initial Decision, 165 FERC ¶ 63,001 at P 999 (citing Trial Staff Initial Brief at 131; *Pac. Gas & Elec. Co.*, 121 FERC ¶ 61,174, at P 7 n.5 (2007); Ex. S-0016 (Testimony of Trial Staff Witness) at 3:14-4:11; Ex. PGE-0002 at 11:5-27).

which consist of \$22.059 million from Wireless (89.5% of the total), \$2.371 million from Wire-Line and \$221,000 from Maintenance and Consulting.⁷⁸⁷

a. Initial Decision

282. The Presiding Judge stated that historically the Commission approved using a 50-50 revenue sharing mechanism of NP&S revenues between PG&E and its ratepayers.⁷⁸⁸ The Presiding Judge stated that under this mechanism, an unreasonably low NP&S net revenue forecast would deprive ratepayers of the share of revenue credit the Commission intended for them to receive.⁷⁸⁹

283. The Presiding Judge explained that PG&E uses different methods to forecast the net revenue of each NP&S.⁷⁹⁰ First, according to the Presiding Judge, to forecast Wireless net revenue, PG&E uses assumptions about the number of existing site, new sites, sites that it will decommission, and prospective additions of new equipment.⁷⁹¹ Second, the Presiding Judge stated that PG&E forecasts its Wire-Line net revenue by focusing on rental revenue from leasing and licensing contracts, and the adding an escalation percentage.⁷⁹² Finally, the Presiding Judge stated that PG&E forecasts Maintenance and Consulting net revenue by averaging the number of emergency responses, and the annual revenue and expenses from these responses.⁷⁹³

284. The Presiding Judge found that the methodologies PG&E uses to forecast NP&S net revenues do not satisfy the *Chatham* chain of reasoning, and therefore the forecasts are not just and reasonable.⁷⁹⁴ The Presiding Judge found “the liner regression upon

⁷⁸⁷ Ex. PGE-0002 at 13, tbl. PGE-0002-1.

⁷⁸⁸ Initial Decision, 165 FERC ¶ 63,001 at P 1000 (citing *Pac. Gas & Elec. Co.*, 132 FERC ¶ 61,272, at P 25 (2010); *Pac. Gas & Elec. Co.*, 128 FERC ¶ 61,288, at P 21 (2009); *Pac. Gas & Elec. Co.*, 124 FERC ¶ 61,305, at PP 19, 26 (2008); *Pac. Gas & Elec. Co.*, 121 FERC ¶ 61,174 at P 1; *Pac. Gas & Elec. Co.*, 106 FERC ¶ 61,058 (2004)).

⁷⁸⁹ *Id.* P 1001.

⁷⁹⁰ *Id.* P 1004.

⁷⁹¹ *Id.* P 1005.

⁷⁹² *Id.* P 1008.

⁷⁹³ *Id.* P 1009.

⁷⁹⁴ *Id.* P 1010 (citing *Chatham*, 662 F.2d at 29).

which the Wireless forecast is based is seriously flawed.”⁷⁹⁵ The Presiding Judge also found the testimony describing the Wire-Line forecast method was deficient because it failed to explain how PG&E calculates its escalation percentages.⁷⁹⁶ Finally, the Presiding Judge found that regardless of the methodologies used, PG&E repeatedly under-forecasted its net revenues between 2006-2015.⁷⁹⁷ The Presiding Judge explained that Trial Staff’s witness provided a viable alternative method for forecasting NP&S net revenues.⁷⁹⁸ As explained in the Initial Decision, Trial Staff’s witness forecast a pre-tax NP&S net revenue forecast of \$32,407,600, and a corresponding customer revenue credit of \$12,057,458.23, based on data available to PG&E at the time of filing.⁷⁹⁹ According to the Presiding Judge, Trial Staff’s witness calculated those numbers by applying a linear regression methodology, based on PG&E’s NP&S net revenues (recorded NP&S revenues minus recorded NP&S expenses) during 2006-2011 and 2013-2015 to calculate a 2017 NP&S net revenue forecast.⁸⁰⁰ Therefore, the Presiding Judge concluded that PG&E’s NP&S net revenue forecast was unjust and unreasonable, and that the utility must adopt Trial Staff’s forecast of NP&S net revenues and its accompanying customer revenue credit for this component.⁸⁰¹

b. Brief on Exceptions

285. TANC contends that the Initial Decision’s finding that identified deficiencies in PG&E’s NP&S forecasting methodologies demonstrates that the Commission must reinstate triennial review process of PG&E’s expenses and revenue forecasts.⁸⁰² TANC

⁷⁹⁵ *Id.* P 1015.

⁷⁹⁶ *Id.* P 1018.

⁷⁹⁷ *Id.* P 1022.

⁷⁹⁸ *Id.* PP 1022-1023.

⁷⁹⁹ *Id.* P 1023 (citing Ex. S-0017 at 1).

⁸⁰⁰ *Id.* (citing Ex. S-0016 at 6:17-7:13; Ex. S-0017 at 3).

⁸⁰¹ *Id.* P 1028.

⁸⁰² TANC Brief on Exceptions at 98-99 (citing *Pac. Gas & Elec. Co.*, 106 FERC ¶ 61,058 at P 2; *Pac. Gas & Elec. Co.*, 90 FERC ¶ 61,314, at 62,039 (2000); *Pac. Gas & Elec. Co.*, 121 FERC ¶ 61,174 at P 2.

contends that monitoring PG&E's forecasting methods is necessary to ensure its methods are appropriate and acceptable.⁸⁰³

c. Briefs Opposing Exceptions

286. PG&E contends that TANC provides no basis for its exception that claims the Initial Decision should order future triennial reviews of PG&E's NP&S forecasts.⁸⁰⁴ PG&E concedes that the Commission used to require triennial filings, but after several years, the Commission removed this requirement.⁸⁰⁵ Therefore, PG&E contends that the Commission should not re-impose the triennial requirement.⁸⁰⁶

287. Trial Staff contends that the Initial Decision was correct to find "the Commission has uniformly approved the continued use of the 50-50 revenue sharing mechanism [for the treatment of NP&S revenues] in numerous proceedings."⁸⁰⁷ Trial Staff cites TANC witness' concession that the 50-50 revenue sharing mechanism is appropriate here.⁸⁰⁸ Therefore, Trial Staff argues that TANC should address its contention to reinstate the triennial review of PG&E's NP&S revenue sharing mechanism is a separate petition.⁸⁰⁹

d. Commission Determination

288. We affirm the Presiding Judge's finding that the methodologies PG&E uses to forecast NP&S net revenues do not satisfy the *Chatham* chain of reasoning and suffered from various deficiencies.⁸¹⁰ We therefore agree with the Presiding Judge that these forecasts are not just and reasonable.⁸¹¹ We accept Trial Staff witness' alternative

⁸⁰³ *Id.* at 99.

⁸⁰⁴ PG&E Brief Opposing Exceptions at 78.

⁸⁰⁵ *Id.* at 78-79 (citing *Pac. Gas & Elec. Co.*, 90 FERC ¶ 61,314; and *Pac. Gas & Elec. Co.*, 121 FERC ¶ 61,174).

⁸⁰⁶ *Id.* at 79.

⁸⁰⁷ Trial Staff Brief Opposing Exceptions at 54 (citing Initial Decision, 165 FERC ¶ 63,001 at P 1000).

⁸⁰⁸ *Id.* (citing Ex. TNC-0018 (revised Sept. 11, 2018) at 88:12).

⁸⁰⁹ *Id.*

⁸¹⁰ 662 F.2d at 29.

⁸¹¹ Initial Decision, 165 FERC ¶ 63,001 at PP 1010-1022.

method for forecasting NP&S net revenues and direct PG&E to adopt it in its revised TO18. Trial Staff's NP&S net revenue forecast is a linear regression calculated based upon actual recorded revenues minus actual recorded expenses.⁸¹² We also reject TANC's request that triennial reviews be reinstated. As PG&E notes, the Commission removed this requirement several years ago, and we see no reason to re-impose it here.

4. Income Tax and ADIT Costs Resulting From the Tax Cuts and Jobs Act

289. PG&E proposed to base its TO18 rates, which were in effect until March 1, 2018, on a 35% corporate income tax rate.⁸¹³ However, the Tax Cuts and Jobs Act of 2017 (Tax Act) lowered the federal corporate income tax rate from 35% to 21% effective January 1, 2018.⁸¹⁴

a. Initial Decision

290. The Presiding Judge stated that PG&E's TO18 rates would stay effective until March 1, 2018.⁸¹⁵ The Presiding Judge stated PG&E's tax rate was based on a 35% federal corporate income tax rate, but the Tax Act would lower this rate to 21% beginning January 1, 2018.⁸¹⁶ PG&E's witness confirmed that the utility would pay the lower rate during TO18 for January and February of 2018.⁸¹⁷ However, as the Presiding Judge explained, PG&E had yet to agree to refund this money to its Network Transmission customers.⁸¹⁸

291. The Presiding Judge explained that the Commission had previously found it was appropriate to revise test year estimates when "it can be demonstrated that the estimates were either unreasonable when made or, if reasonable when made, subsequent events indicate that to use them as a basis for future projects would yield unreasonable results."⁸¹⁹ In prior cases, the Commission ordered the utility to revise its rates to reflect

⁸¹² Tr. 697:14-699:25 (Tam).

⁸¹³ See Tr. 650:25-651:6, 651:14-16 (Battin)

⁸¹⁴ Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

⁸¹⁵ Initial Decision, 165 FERC ¶ 63,001 at P 1032.

⁸¹⁶ *Id.* P 1032 (citing Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, 131 Stat. 2045 (2017); Tr. 651:14-16) (Battin)).

⁸¹⁷ *Id.* P 1036 (citing Tr. 662:16-19 (Battin); Tr. 1720:22-171:1 (Majoros)).

⁸¹⁸ *Id.* P 1036.

⁸¹⁹ *Id.* P 1038 (citing *Sw. Pub. Serv. Co.*, 49 FERC ¶ 61,354, at 62,282 (1989);

the tax rate change.⁸²⁰ Accordingly, the Presiding Judge found that PG&E must revise its January and February 2018 income tax and ADIT calculations to reflect the 21% tax rate and refund its Network Transmission customers.⁸²¹

b. Briefs on Exceptions

292. PG&E states that the Commission has explained that “with respect to the corporate tax rate reduction in the Tax Reform Act of 1986, the Commission has required reductions to cost-of-service where the Act was enacted during the test period and the effected date of the reduction occurred within, or soon after, the test period.”⁸²² Here, the Tax Cuts and Jobs Act was enacted after the end of the test period and was not signed into law until December 22, 2017.⁸²³ PG&E thus requests the Commission reject the tax adjustment because of the complication of double counting that would occur from the TO18 settlement and the resolution of the Tax Cuts and Jobs Act.⁸²⁴

293. TANC contends that PG&E should use the tax rate adjustment to compute its after-tax share of net revenues from NP&S.⁸²⁵ TANC argues that PG&E should apply the correct federal corporate tax rate to the January and February 2018 NP&S.⁸²⁶

c. Briefs Opposing Exceptions

294. PG&E notes that on November 15, 2018 the Commission issued an order to show cause, which directed PG&E to show cause as to why its TO18 rates should not reflect

SoCal Edison, 8 FERC at 61,375).

⁸²⁰ *Id.* (citing *Sw. Pub. Serv. Co.*, 49 FERC at 62,283; *Kan. Gas & Elec. Co.*, 49 FERC ¶ 61,295, at 62,123-24 (1989); *Boston Edison Co.*, 42 FERC ¶ 61,374, at 62,097 (1988)).

⁸²¹ *Id.* P 1039.

⁸²² PG&E Brief on Exceptions at 87 (citing *Williston Basin Interstate Pipeline Co.*, 52 FERC ¶ 61,170, at 61,645 & n.26 (1990) (*Williston*)).

⁸²³ *Id.* at 87-88.

⁸²⁴ *Id.* at 88.

⁸²⁵ TANC Brief on Exceptions at 98.

⁸²⁶ *Id.*

the reduced federal corporate income tax.⁸²⁷ According to PG&E, the Commission found that “the Consolidated TO19 Rate Proceeding is a comprehensive rate case looking at all aspects of PG&E’s rate and is an appropriate forum to investigate the impacts of the Tax Cuts and Jobs Act,” and thus concluded that PG&E had shown cause as to why its stated transmission rates should not be revised to reflect the reduced federal corporate income tax rate.⁸²⁸ Therefore, PG&E contends that the Commission should reject the Initial Decision’s tax adjustment recommendation.⁸²⁹

295. TANC contends that the Initial Decision’s directive that PG&E revise its federal corporate income tax and ADIT calculations to reflect the 21% tax rate and to refund its Network Transmission customers is correct.⁸³⁰ TANC argues that the Commission should reject PG&E’s exception to the Initial Decision’s ruling.⁸³¹ TANC contends that PG&E’s argument that under the TO19 settlement the TO18 ADIT will automatically flow back to customers is inaccurate.⁸³² TANC argues “the flow back of excess [ADIT] under the TO19 settlement is effective March 1, 2018. Accordingly, if the Commission reverses the Initial Decision in this regard, transmission customers will be denied of any flow back of excess [ADIT] PG&E has collected during the months of January and February 2018.”⁸³³ Thus, TANC contends that the Commission should order PG&E to return any excess ADIT to customers.⁸³⁴ TANC also contends that the *Williston* order PG&E cites is distinguishable because, here, Congress enacted the Tax Cut and Jobs Act during the test year and it became effective only one day after the end of the test year.⁸³⁵ Finally, TANC contends that PG&E’s claim that the Commission does not correct tax rate changes after the end of a test period is wrong.⁸³⁶ TANC claims that the

⁸²⁷ PG&E Brief Opposing Exceptions at 78.

⁸²⁸ *Id.* (citing *Pac. Gas & Elec. Co.*, 165 FERC ¶ 61,131, at P 19 (2018)).

⁸²⁹ *Id.*

⁸³⁰ *Id.* at 93.

⁸³¹ *Id.*

⁸³² *Id.* at 95.

⁸³³ *Id.*

⁸³⁴ *Id.*

⁸³⁵ *Id.* at 96.

⁸³⁶ *Id.* (citing PG&E Brief on Exceptions at 88).

Commission makes an exception where there are “known and measurable changes of substantial nature.”⁸³⁷ TANC contends that the reduction from 35% to 21% is a known and measurable change of substantial nature, and therefore the Commission should order PG&E to revise its income tax rate for January and February 2018.⁸³⁸

d. Commission Determination

296. On March 15, 2018, the Commission issued a show cause order requiring PG&E to either (1) propose revisions to its stated transmission rate to reflect the reduced corporate tax rate; or (2) show cause why it should not be required to do so.⁸³⁹ PG&E filed a response to the Show Cause Order stating that no revisions are necessary to its transmission rate because it was addressing the reduced federal income tax rate in its TO19 Proceeding. The Commission accepted PG&E’s response.⁸⁴⁰ TANC did not request rehearing in the Show Cause proceeding. On December 20, 2018, the Commission approved an uncontested offer of settlement in the TO19 Proceeding.⁸⁴¹ On February 21, 2019, the Commission also granted PG&E’s unopposed motion to dismiss it from the Show Cause proceeding.⁸⁴² The issue of the tax cuts impact on PG&E’s

⁸³⁷ *Id.* at 97 (citing *Nat’l Fuel Gas Supply Corp.*, 51 FERC ¶ 61,122, at 61,334 (1990); *Papago Tribal Util. Auth. v. FERC*, 773 F.2d 1056, 1059, 1063 (9th Cir. 1985)). TANC states that the Commission has held it was obligated to require a regulated company adjust rates to a date outside of the test period to reflect changes in the tax law enacted during the test period. *Id.* (citing *Nat’l Fuel Gas Supply Corp.*, 51 FERC ¶ 61,334).

⁸³⁸ *Id.* at 98. TANC also argues that the Commission should reject PG&E’s allegation of bias. *Id.* at 94.

⁸³⁹ *Alcoa Power Generating Inc.—Long Sault Division*, 162 FERC ¶ 61,224, at P 4 (2018) (Show Cause Order).

⁸⁴⁰ *Pac. Gas & Elec. Co.*, 165 FERC ¶ 61,131, at P 18 (2018). TANC’s protest of PG&E’s response in the Show Cause proceeding was rejected by the Commission. *Id.* P 19.

⁸⁴¹ *Pac. Gas & Elec. Co.*, 165 FERC ¶ 61,244 (2018). We also note that TANC was an active party to the TO19 Proceeding. See *Pac. Gas & Elec. Co.*, 160 FERC ¶ 61,128, at PP 9, 21 (2017).

⁸⁴² *Pac. Gas & Elec. Co.*, 166 FERC ¶ 61,130 (2019).

January and February 2018 rates has therefore been resolved in the TO19 Proceeding. Accordingly, we find that this issue as moot and therefore dismiss it.⁸⁴³

III. Conclusion

297. As discussed herein, we affirm in part and reverse in part the Presiding Judge's Initial Decision. We also direct further briefing on the issue of how PG&E's base ROE should be calculated, as discussed above. Initial briefs shall be due 60 days from the date of this order. Responses to those initial briefs shall be due 30 days later. No answers or additional briefs will be permitted. We also direct PG&E to submit, within 60 days of the date of the order on the ROE issue discussed above, a compliance filing to reflect adjustments to its TRR as required by this order and the order on further briefing.

The Commission orders:

(A) The Presiding Judge's findings are hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) Further briefing is hereby directed on the issue of how PG&E's base ROE should be calculated, as discussed above. Initial briefs shall be due 60 days from the date of this order. Responses to those initial briefs shall be due 30 days later. No answers or additional briefs will be permitted.

(C) PG&E is hereby directed to submit a compliance filing reflecting adjustments to its TO18 TRR in accordance with the directives in the body of this order and a future order on the ROE issue, with such filing due within 60 days of the date of issuance of the order on the ROE issue, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

⁸⁴³ Finally, as we stated earlier, we reject PG&E's claims that the Presiding Judge is biased against stated rates.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY for	)	
accounting approval of depreciation rates for	)	Case No. U-15629
gas utility plant.	)	
_____	)	

At the September 29, 2009 meeting of the Michigan Public Service Commission in Lansing,
Michigan.

PRESENT: Hon. Orjiakor N. Isiogu, Chairman
Hon. Monica Martinez, Commissioner
Hon. Steven A. Transeth, Commissioner

OPINION AND ORDER

History of Proceedings

On July 31, 2008, Consumers Energy Company (Consumers) filed an application, with supporting testimony and exhibits, requesting approval of revised depreciation accrual rates for accounting and ratemaking purposes for the company's gas utility plant. The company also requested a determination that it had substantially complied with the June 26, 2007 order in Case No. U-14292 (June 26 Order).

On November 26, 2008, a prehearing conference was conducted before Administrative Law Judge James N. Rigas (ALJ). The ALJ granted petitions to intervene filed by Attorney General Michael A. Cox (Attorney General) and the Association of Businesses Advocating Tariff Equity (ABATE). The Commission Staff (Staff) also participated in the proceeding.

On December 3, 2008, Consumers filed a partial settlement agreement in this docket in which all parties agreed that the Commission should authorize the company to implement a proposed depreciation schedule from the date that Consumers implemented the settled retail rates in Case No. U-15506 until the Commission issues a final order in this proceeding. The parties to the settlement noted that implementing the proposed depreciation rates would decrease Consumers' depreciation expense by \$19.6 million annually from the depreciation schedule authorized before the settlement. On December 23, 2008, the Commission approved the settlement agreement.

Evidentiary hearings were conducted on April 27 and 28, 2009. On May 15 and May 27, 2009, the parties filed briefs and reply briefs. On July 1, 2009, the ALJ issued his Proposal for Decision (PFD). On July 17, 2009, Consumers, the Staff, and ABATE filed exceptions. On July 31, 2009, Consumers, the Staff, the Attorney General, and ABATE filed replies to exceptions. The record in this case consists of 340 pages of testimony and 28 exhibits received into evidence.

Positions of the Parties

Dane A. Watson of Alliance Consulting Group performed a depreciation study for Consumers and also provided the alternative net salvage calculations required by the June 26 order.

Mr. Watson testified that he calculated cost of removal expense using the traditional method (i.e., the straight line average group life method), the five-year net salvage method, the Statement of Financial Accounting Standards (SFAS) No. 143 approach, and the inflation adjusted method. 2 Tr 48, 52. According to Mr. Watson, his analysis using the traditional approach supports a reduction in depreciation expense of approximately \$19.7 million per year. 2 Tr 52-54.

Mr. Watson testified that Consumers' depreciation expense is decreasing largely because of a reduction in realized removal cost over the past few years, which in turn has allowed the company to lower the projected cost of future removals.

Mr. Watson observed that net salvage rates for Consumers were last approved in Case Nos. U-12999 and U-13730 using the average five-year net salvage percent of retirements.

Mr. Watson testified that using this approach would result in a more negative net salvage rate and higher depreciation expense than the traditional approach. 2 Tr 58-59. Mr. Watson opined that the traditional approach is more appropriate than the five-year average percent of retirements method because the traditional approach allows for the reflection of trends in net salvage.

Mr. Watson explained that under the SFAS No. 143 method, the net present value (liability) and removal cost expense were calculated in the same manner that Consumers calculates its legal Asset Retirement Obligations (AROs) for reporting in financial statements. 2 Tr 62; Exhibit A-3. Mr. Watson testified that in the inflation adjusted approach, he adjusted the inflation for the remaining future years of the assets based on the difference between the 30-year average historical inflation rate and the 30-year average projected inflation rate. 2 Tr 63; Exhibit A-4. Mr. Watson contended that the SFAS No. 143 approach was not appropriate for regulatory accounting because: 1) it was created solely for financial reporting purposes; 2) the Federal Energy Regulatory Commission (FERC) has stated that there is no reason to change to this method; 3) SFAS No. 143 accounting defers depreciation expense to future customers; 4) depreciation expense for removal cost increases every year requiring annual filings to ensure appropriate cost recovery in rates; and 5) it is difficult to accurately calculate liabilities or accretion under the SFAS No. 143 approach for mass property. 2 Tr 64.

Mr. Watson testified that the inflation adjusted approach was likewise problematic because it is impossible to predict future inflation and because the average ages of retirements are generally much shorter than the average life of the accounts. Thus, more years of inflation will act upon the

assets in the future as the average age of retirements moves toward the average life of the account. This will move the net salvage percentages more negative than is reflected in the current analysis.

Mr. Watson added that the traditional method of estimating future salvage and removal costs is the approach authoritative sources generally support, citing the publication *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC) and the 1994 treatise *Depreciation Systems*, by Wolf and Fitch. 2 Tr 66-67.

Jan C. Anderson, the Manager of Depreciation Studies and Regulatory Filings for Consumers, testified that Consumers reviewed its records and determined that a retrospective change in retirement units using the Staff's proposed Standard Retirement Units (SRUs) would be an administrative burden, if it was feasible at all. According to Ms. Anderson:

The Company has electronic files for the more recent years of 1999 through to present that could be electronically reviewed. But, prior to that time, manual work orders would need to be reviewed. Although we don't have an exact historical work order count, with 1.7 million gas services, 26,000 miles of gas distribution main, and 1,700 miles of gas transmission main, it is estimated that more than two million work orders were processed to record these assets. And if it is conservatively estimated that each order would take only five minutes to review and repost using the proposed Standard Retirement Units, it would require 80 full time employees each working for a full year on this and nothing else, to convert the historical information to the Staff's proposed Standard Retirement Units.

2 Tr 23-24.

Ms. Anderson added that despite the difficulty in converting past accounts, Consumers would support the use of the Staff's proposed SRUs on a going-forward basis. Ms. Anderson recommended that the changes in retirement units should be effective on the first day of the subsequent year, provided there is at least 90 days from the order date to the first day of the subsequent year. In addition, the change in retirement units should be effective concurrent with an order in a general rate case.

The Staff recommended that the Commission adopt Consumers' depreciation method and depreciation rates, noting that it agreed with Consumers' analysis of the shortcomings of the alternative methods and added that the traditional method produces reasonable results without being overly burdensome or overly reliant on analytical tools. The Staff also recommended that the Commission reject Consumers' failure to perform the depreciation study using the recommended SRUs as required by the June 26 Order. The Staff noted that no party addressed Consumers' failure to conduct this study, and added that this issue was contested by the parties to Case No. U-14292. The Staff recommended that the Commission direct Consumers to conduct the study and to file it at a date to be set at the Commission's discretion.

The Staff recommended that the traditional method should continue to be used for determining the net salvage for Consumers' gas plant depreciation, and that the company's net salvage calculations should be adopted in this case. The Staff recommended that the rates and service lives set forth by the company in this case should also be adopted and that Consumers' next gas depreciation study should be filed two years from the date of issuance of the order in this case. Following this, the Staff recommended that regular depreciation cases should be filed every three to four years. Finally, the Staff recommended that Consumers perform a study of its cost of removal and salvage practices as part of its next depreciation study for the purpose of keeping these costs under control.

William W. Dunkel, the principal of William Dunkel and Associates, testified on behalf of the Attorney General. Mr. Dunkel asserted that the traditional method for calculating future cost of removal overrecovers removal costs in general and that the overrecovery is more significant in the early years when removal costs are collected. 2 Tr 149, 156. Mr. Dunkel explained that under the traditional approach, the current removal cost for new plant is established, and this cost is then

inflated to the year of removal to determine the future cost of removal. This future removal cost is then divided by the number of years of service to derive the annual amount that must be collected to retire the plant. Mr. Dunkel provided an example of a current removal cost of \$50 for a pipeline expected to last 50 years. Applying inflation, the future cost of removal of the pipeline is calculated to be \$649. Under the traditional method, the company must collect \$12.98 per year ($\$649/50$) to cover the cost of removal. 2 Tr 153. According to Mr. Dunkel, the traditional approach fails to take into account the difference in purchasing power of current dollars compared to future dollars. Mr. Dunkel testified, “Calculating that \$12.98 in Year 2057 dollars is owed, but collecting \$12.98 in Year 2007 dollars is an overcharge, because Year 2007 dollars are worth much more than Year 2057 dollars.” 2 Tr 154.

Mr. Dunkel testified that the traditional approach was developed at a time when net salvage tended to be positive. Now, however, net salvage is more likely to be negative and, according to Mr. Dunkel, the theory on which the traditional approach is based was not designed to properly handle prepayments by customers.

Mr. Dunkel advocated that the Commission adopt a depreciation method that he called the “Present Value/SFAS 143/FERC Order 631” approach. Mr. Dunkel testified that under this approach, customers in 2007 are required to pay the present value of their share of the future removal cost. Thus, 2007 customers are responsible for paying \$12.89 in 2057 dollars, rather than 2007 dollars. In year 2007, customers would pay enough such that the money they paid, plus 50 years of interest on that money, would sum to the \$12.89 needed for their share of the removal cost in year 2057 in 2057 dollars. 2 Tr 164.

James T. Selecky, a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., testified on behalf of ABATE. According to Mr. Selecky,

Consumers' proposed depreciation rates are excessive because the cost of removal component of the depreciation rates reflects unreasonable amounts for future inflation. As a result, the cost of removal expense included in the depreciation rates greatly exceeds the actual net salvage expense currently incurred and the net salvage expense likely to be incurred in the near future.

Mr. Selecky testified that Consumers' proposed net salvage ratios produce an annual net salvage expense of \$52.92 million. However, according to Mr. Selecky, Consumers' average actual annual net salvage expense over the last five years was \$6.89 million, an amount that is 8 times lower than the company's proposed cost of removal expense. 3 Tr 298. Mr. Selecky testified that based on his analysis, Consumers has overstated the amount of net salvage that is included in depreciation rates and that this overstatement of net salvage places an unreasonable burden on today's ratepayers and provides a substantial benefit to future ratepayers. Mr. Selecky opined that the amount of net salvage included in Consumers' depreciation rates should be reduced to reflect a more accurate expectation of the level of net salvage expense that the company expects to incur over the next five to ten year period. Mr. Selecky testified that the disparity between net salvage expense included in Consumers' depreciation rates and actual net salvage costs is largely attributable to an overestimate of future inflation rates.

Mr. Selecky recommended that Consumers' net salvage expense should be based on the actual net salvage cost experience of the company over 15 years, the longest period for which data was available. Once the historical 15-year average was identified, this amount was then grossed-up for inflation over a period of 10 years to determine an average accrual of \$9.956 million for net salvage. 3 Tr 314-315; Exhibits AB-3 and AB-4. Mr. Selecky noted that periodic depreciation cases will allow for adjustments if cost of removal expense increases in the future.

Proposal for Decision

The ALJ noted that the parties did not disagree on Consumers' method for calculating depreciation expense and rates related to the recovery of original plant investment cost but did disagree on how the company should calculate depreciation expense and rates for recovery of net salvage costs. The ALJ prefaced his findings by observing that the June 26 order established the Commission's view that comparing removal costs in today's dollars with the original cost of the plant being retired is problematic because it assumes that high inflation rates from the past will continue into the future and fails to take into account the time value of money. The ALJ found that the traditional method for calculating future removal costs, as advocated by the Staff and Consumers, did not address the concerns in the June 26 order because the traditional method does not address the time value of money or significant depreciation expense accruals.

The ALJ agreed with ABATE that the traditional method does not provide reasonable or accurate results, and agreed with Consumers and the Staff that because the method proposed by ABATE uses a time span that is much shorter than the service life of the plant items being depreciated, this method will not permit the utility to recover its actual plant in service retirement costs.

The ALJ found that the record provides a choice between Consumers' SFAS No. 143 method and the Attorney General's proposed present value method. The ALJ determined that the method presented by the Attorney General was least problematic and recommended its adoption by the Commission. The ALJ added that periodically reviewing the present value calculations will provide the opportunity for refinement and will address the concerns about the accuracy of the results.

The ALJ agreed with the Staff's recommendation that consideration of SRU's should be deferred to the rulemaking proceeding in Case No. U-14812 and with the Attorney General's recommendation that Consumers should be required to file its cost of removal study and next depreciation case two years after the final order in this case.

Exceptions and Replies

Consumers takes exception to the ALJ's recommendation that the present value method should be adopted for calculating net salvage. According to Consumers, the present value method causes current customers to underpay and forces later customers to pay too much for removal costs. Consumers argues that in addition to this inequity, future customers will also face a higher rate base, which will cost them more for carrying the cost of the assets' net book value; they will pay more for maintenance expenses; and they will pay more for future assets that are capitalized at a higher cost. Consumers asserts that the ALJ failed to recognize that under regulated accounting, every dollar of removal cost recovered from customers is charged to the depreciation reserve, and every dollar added to the reserve decreases Consumers' rate base. Consumers claims that adoption of the present value approach would result in a 50% increase in both future value cost and current value cost over the traditional method's straight-line recovery of removal costs.

Consumers argues that the ALJ erred in finding that the traditional method does not provide reasonable or accurate results and erred by selectively applying language from the June 26 order. Consumers points to the Commission's concerns about the size of the company's cost of removal expense, noting that subsequent to the June 26 order the company reduced its cost of removal expense by over \$19 million per year. According to Consumers, this reduction, coupled with the company's commitment to file another depreciation study in two years, addresses this concern. Consumers adds that the ALJ ignored the language in the June 26 order characterizing the

Attorney General's proposed present value approach as "radical." Consumers adds that the Attorney General's proposed reduction of \$47.5 million from the levels set in Case No. U-12999 demonstrates that the Commission's concerns about the Attorney General's approach were sound. Consumers claims that such a substantial reduction could have a significant adverse effect on the company's cash flow. Consumers also asserts that, despite the Attorney General's opinion to the contrary, the company would have to file a depreciation case every year to assure full cost recovery.

Finally, Consumers argues that if the Commission determines that an SFAS No. 143 approach to cost of removal calculation is most appropriate, the Commission should adopt the SFAS No. 143 approach presented by Consumers. Consumers argues that the calculation presented by Mr. Dunkel violates a basic requirement of SFAS No. 143: that the calculation must use the future value of removal costs at the planned time of removal. Consumers notes that Mr. Dunkel used 22.8 years as the average age of asset retirements, rather than the projected asset retirement age of 40 years. The \$28 million difference between Consumers' SFAS No. 143 method and Mr. Dunkel's version is the result of Mr. Dunkel's exclusion of 17 years of inflation.

The Staff likewise takes exception to the ALJ's recommendation that the Attorney General's present value method should be adopted for calculating future cost of removal expense. The Staff claims that, contrary to the ALJ's finding, shifting costs to future ratepayers by implementing the present value method will create intergenerational inequities because these inequities are intrinsic to the method. The Staff adds that the intergenerational inequity created by the present value method would not necessarily be corrected by holding depreciation cases on a regular basis.

ABATE argues that the ALJ erred in rejecting its approach for calculating net salvage. According to ABATE, the ALJ summarized the advantages of using the 15-year average historical

net salvage expense inflated for 10 years, but then rejected it on grounds that it uses a much shorter period than the service life of the plant being depreciated and resulted in a significant reduction in cost of removal expense. ABATE argues that it is unreasonable to find a method that uses future predictions of net salvage expense preferable to one that uses the best available historical information coupled with a future estimate of inflation. ABATE observes that all of the advantages associated with the SFAS No. 143 method are true of ABATE's proposed approach; however, the approach advocated by ABATE has the additional advantage of a basis in actual historical data.

Findings of Fact and Conclusions of Law

On October 14, 2004, the Commission issued an order in Case No. U-14292 requesting comments regarding "[the] future treatment of FAS No. 143-related issues, proper future ratemaking policy regarding those issues, necessary uniform system of accounts revisions, and other matters that are related to the retirement of tangible long-lived assets and the associated asset retirement costs." After reviewing the comments, the Commission issued a final order on June 26, 2007. In the June 26 order, the Commission observed, among other things, that, "an SFAS No. 143 approach applied to required [asset retirement obligations] ARO and other ARO accounts would be informative, even if the Commission determines that SFAS No. 143 should not be used for ratemaking." The Commission then directed the large utilities to:

[F]ile new depreciation cases in 2008, using 2007 cost of removal expenses as a basis, and to calculate cost of removal depreciation under: 1) the current method for calculating cost of removal; 2) the current method for calculating cost of removal using the standard retirement units proposed by the Staff; 3) the method proposed by Mr. Czech and using the standard retirement units proposed by the Staff; and 4) an SFAS No. 143 approach that considers the time value of money applied to required AROs and other AROs, with and without the standard retirement units proposed by the Staff. This additional information will allow the

Commission to assess the propriety of the different proposals and the efficacy of implementing them for each individual utility.

June 26 order, p. 33.

The Commission agrees with Consumers and the Staff that continued use of the traditional, straight-line depreciation method, coupled with the use of the Staff's proposed SRUs on a going-forward basis, is the most appropriate means of addressing future removal costs. As discussed by Mr. Watson in his rebuttal testimony, the net present value approach proposed by the Attorney General has been consistently rejected by most Commissions and does not comport with depreciation methods recommended by authoritative sources on depreciation accounting. The accrual for net salvage must be based on estimates of the future cost that will be incurred, not the removal cost at today's price level. Therefore, it is appropriate to ask current customers to pay for future costs of removal at inflated price levels, and, as Mr. Watson pointed out, the rate base offset compensates rate payers for the prior payment for the costs incurred by the utility. Finally, the Commission finds that the Attorney General's proposed method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations. This, in turn, has a negative financial effect on both the utility and its customers by requiring that such obligations be met with more expensive sources of external financing and by driving up the cost generally of obtaining money in the capital markets. The Commission finds that the Attorney General has not shown that the adoption of the net present value method would justify these increased costs for utility consumers.

The Commission disagrees with the Staff's recommendation that Consumers should be required to perform a depreciation study using the Staff's recommended SRUs as required by the June 26 order. While it is true that there was some dispute over the effects of changing to SRUs, the amount of effort required to update older, non-electronic records was not contemplated by the

Commission or the utilities. The Commission therefore agrees with Consumers that the Staff's recommended SRUs should only apply on a going-forward basis.

THEREFORE, IT IS ORDERED that:

A. Consumers Energy Company shall continue the depreciation rates authorized by the December 23, 2008 order approving a partial settlement agreement in this case.

B. Consumers Energy Company shall file a new depreciation case and an updated depreciation study by September 15, 2011.

C. Consumers Energy Company shall use standard retirement units proposed by the Commission Staff in Case No. U-14292 for new gas plant effective January 1, 2010.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26.

MICHIGAN PUBLIC SERVICE COMMISSION

Orjiakor N. Isiogu, Chairman

By its action of September 29, 2009.

Monica Martinez, Commissioner

Mary Jo Kunkle, Executive Secretary

Steven A. Transeth, Commissioner

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-15629

County of Ingham)

Mignon Middlebrook being duly sworn, deposes and says that on September 29, 2009 A.D. she served a copy of the attached Commission orders by first class mail, postage prepaid, or by inter-departmental mail, to the persons as shown on the attached service list.

Mignon Middlebrook

Subscribed and sworn to before me
this 29th day of September 2009

Sharron A. Allen
Notary Public, Ingham County, MI
My Commission Expires August 16, 2011

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FILED

DEC 21 2010

**EXECUTIVE SECRETARY
G.P.S.C.**

DEBORAH K. FLANNAGAN
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STATE OF GEORGIA

**In RE: Petition of Atlanta Gas Light
Company for Approval of Adjustment
of its Rates and Revised Tariff**

DOCKET# Docket No. 31647

DOCUMENT# 132939

FINAL ORDER

APPEARANCES

FOR THE GEORGIA PUBLIC SERVICE COMMISSION PUBLIC INTEREST
ADVOCACY STAFF: Philip J. Smith, Alex Sponseller; FOR ATLANTA GAS LIGHT
COMPANY: L. Craig Dowdy, Elizabeth Wade, John C. Allen; FOR GAS SOUTH, LLC: D.
Mark Baxter, Meredith W. Hodges; FOR GEORGIA WATCH: Clare McGuire; FOR
RESOURCE SERVICE MINISTRIES: Michael O. Kimsey; FOR RESOURCE SUPPLY
MANAGEMENT: Jim Clarkson; FOR SCANA ENERGY MARKETING, INC.: William
Bradley Carver, Joseph B. Newsom; FOR SOUTHSTAR ENERGY SERVICES LLC d/b/a
GEORGIA NATURAL GAS: Robert B. Remar, Thomas Mew, Joseph C. Monroe.

Final Order

JURISDICTION

O.C.G.A. § 46-2-20(a) provides that the Commission has general supervisory authority over gas companies.

O.C.G.A. § 46-2-23 provides that the Commission has exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm or corporation subject to its jurisdiction. The rates for firm distribution service and ancillary services rendered by an electing distribution company must be established in accordance with Article 5 of Title 46, O.C.G.A. §§ 46-4-151 *et seq.*

O.C.G.A. § 46-2-25 provides in pertinent part that whenever any new rate schedule is filed, the Commission shall have authority, upon reasonable notice to the utility, to enter a hearing concerning the lawfulness of such rate, charge, classification, or service.

O.C.G.A. § 46-2-26.4 provides for the accounting treatments to be used in any proceeding before the commission to determine the rates to be charged by a gas utility. Subsection (b) provides as follows:

In any proceeding commenced after April 1, 2002, to determine the rates to be charged by a gas utility, the gas utility shall file jurisdictionally allocated cost of service data on the basis of a test period, and the commission shall utilize a test period, consisting of actual data for the most recent 12 month period for which data are available, fully adjusted separately to reflect estimated operations during the 12 months following the proposed effective date of the rates. After the initial filing, and until new rates go into effect, the utility shall file actual cost of service data as they become available for each month following the actual data which were filed. The utility shall have the burden of explaining and supporting the reasonableness of all estimates and adjustments contained in its cost of service data.

STATEMENT OF PROCEEDINGS

Pursuant to a Stipulation adopted by the Georgia Public Service Commission ("Commission") on June 17, 2005 in Docket No. 18368-U, the Commission and Atlanta Gas Light Company ("Atlanta Gas Light" or "Company") agreed to freeze base rates until April 10, 2010. The Stipulation provided in Paragraph 1 that the Company would file a rate case on November 1, 2009:

AGLC's base rates shall be frozen at their April 30, 2005 levels for a period of five years beginning May 1, 2005 and ending April 30, 2010 with the Company agreeing not to seek a rate increase and the Commission agreeing not to bring AGLC in for a rate proceeding during that period. On November 1, 2009 the Company shall file testimony and exhibits required in a general rate case filing along with supporting schedules required by the Commission to support a "traditional" rate case. Based on this settlement agreement, the test year utilized by the Company in its rate case filing shall be from December 1, 2009 to November 30, 2010.

June 17, 2005 Order on Reconsideration, Exhibit A, Para. 1.

Mindful of the difficulties faced by end-use customers in the current economic climate and acting under the belief that it could continue to operate under then-current levels for a brief period beyond the date new rates were to be effective under the prior order, on July 15, 2009, the Company filed a Petition to Postpone Scheduled Rate Filing. In an August 5, 2009 Order, the Commission agreed to permit the Company to file its next rate case on a date no sooner than April 1, 2010, but no later than June 1, 2010.

On April 28, 2010, the Commission issued a Procedural and Scheduling Order in the above-captioned docket directing the Company to file a general rate case on or before May 3, 2010, with proposed rate changes to become effective November 3, 2010. In that procedural order, the Commission suspended the filing as contemplated by O.C.G.A. § 46-2-25 for a five-month period ending November 3, 2010 and directed that the test period to be utilized shall cover the twelve month period ending May 31, 2011. The Commission also ordered that the following issues would be addressed in this proceeding:

- (a) For the test year period, what is Atlanta Gas Light Company's total revenue requirement? As part of the consideration of total revenue requirement, what are Atlanta Gas Light Company's just and reasonable operating expenses, depreciation expense, taxes, rate base and cost of capital?
- (b) For the test year period, what is the total revenue Atlanta Gas Light Company should be authorized to collect through the rates charged for its distribution services?
- (c) Are Atlanta Gas Light Company's rates just and reasonable and do they recover more or less than the Company's revenue requirement?
- (d) For the test year period, if Atlanta Gas Light Company's current rates are not just and reasonable, how should Atlanta Gas Light Company's rates be

modified so that the new rates are just and reasonable and reflect the Company's revenue requirement?

- (e) Are affiliate transaction costs fairly allocated?
- (f) Is the jurisdictionally allocated cost of service data fully adjusted separately to reflect estimated operations during the twelve (12) months following the proposed effective date of the rates? See O.C.G.A. § 46-2-26.4(b)?
- (g) Should the Pipeline Replacement Rider, or any other rider, be modified and if so, in what manner?
- (h) Should AGLC's Tariff be modified and updated?

In addition to participation by the Georgia Public Service Commission Public Interest Advocacy Staff ("PIAS") in this matter, interventions were filed by a number of interested parties. These interested parties included Gas South, LLC ("Gas South"); Georgia Watch; Resource Service Ministries; Resource Supply Management; SCANA Energy Marketing, Inc. ("SCANA"); and Southstar Energy Services, LLC d/b/a Georgia Natural Gas ("Southstar" or "GNG").

Hearings on AGLC's general rate case began on August 10, 2010, at which time the Commission received the testimony of numerous Company witnesses on behalf of AGLC, and concluded on August 11, 2010.

On August 19, 2010, PIAS pre-filed direct testimony. On August 19, 2010, Resource Service Ministries pre-filed the direct testimony of Michael O. Kimsey. Hearings on this second phase of the case began on September 13, 2010, during which seven public witnesses provided comments and the above-referenced parties testified, and concluded on September 14, 2010.

On October 1, 2010 AGLC filed rebuttal testimony regarding the testimony of the PIAS' witnesses, and, on Tuesday, October 12, 2010 hearings in this proceeding resumed, concluding on October 13, 2010.

On October 20, 2010, parties in this matter filed proposed orders and briefs.

At the Special Administrative Session on October 27, 2010, the Commission considered and decided the issues presented to it in this proceeding.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

I Revenue Requirements

A. Atlanta Gas Light Company Rate Base

1. Utility Plant

Atlanta Gas Light Company's ("AGLC") utility plant for the test year was represented as being \$2,926,451,000 less a depreciation reserve of \$1,118,867,000. As discussed above, the test year set for this proceeding is the 12-month period ending May 31, 2011. These amounts include AGLC's proposed Customer First programs, and the depreciation reserve includes the depreciation rates proposed by Company witnesses Watts and Watson. Utility plant for the test year is comprised of the original proposed amount of \$2,920,023,000 (AGLC Exhibit No. 39 (MJM-4) Revised, Schedule 1 Revised, Column 8, Line 1) and an additional \$6,428,000 provided with the Company's errata (AGLC Exhibit No. 39 (MJM-4) Revised, Schedule 1a, sum of lines 1 and 6). The depreciation reserve for the test year consists of the original proposed amount of \$1,119,413,000 (AGLC Exhibit No. 39 (MJM-4) Revised, Schedule 1 Revised, Column 8, Line 3) less an adjustment for \$546,000 that is required to correct the depreciation rate used for general plant.

PIAS contends that an end of test period amount is more appropriate if the Commission adopts the Company's post test period adjustment associated with the implementation of the automated meter reading ("AMR") program. Tr. 937-41. PIAS also asserts that the Company will over earn in future years if an end of test year methodology is not adopted. (*Id.*). The Commission rejects PIAS' proposal of an end of test period methodology. PIAS' approach is not consistent with basic ratemaking principles and is not consistent with PIAS' own methodology adopted in previous rate cases. PIAS' contention that the Company will over earn in future years is not supported by the evidence in this case, and PIAS' analysis does not include potential decreases in revenues or potential increases in interest rates, benefit costs or other increases in rate base such as the Company's prepaid pension asset. Further, the Company was consistent in applying a post test year approach for the AMR program by also including post test year savings for the cost of service component associated with the program. The Commission rejects PIAS' proposal of an end of test period methodology. As provided in AGLC Exhibit No. 119 (MJM-7), use of a post test year methodology for the AMR program saves customers approximately \$200,000 in annual revenue requirement. Therefore, the Commission considers the Company's methodology for estimating utility plant just and reasonable and rejects PIAS' end of test year methodology.

2. AGL Services Company Plant

Included in the Company's test year rate base is approximately \$24 million of AGL Services

Company ("AGSC") net plant that the Company stated is used for AGLC's utility service to Georgia gas consumers. AGSC net plant includes an allocable portion of plant in service, construction work in progress, accumulated depreciation reserve and accumulated deferred income taxes. According to company witness Morley, these assets are utilized by employees of AGLC and AGSC in providing utility service to AGLC customers and would otherwise be reflected on the books and records of the Company if it were not a subsidiary of AGL Resources but a stand-alone company. Tr. 452. PIAS did not dispute these facts. Mr. Morley also stated that the Company's requested treatment of AGSC assets is consistent with this Commission's prior rate case decision in Atmos Energy's rate case in Docket No. 30442. (*Id.*). PIAS recommended excluding AGSC net plant from rate base because AGSC is a separate legal entity. Tr. 1100-01. PIAS also contended that AGSC finances its operations and that AGSC did not incur financing costs in the historic test year. AGLC contends that AGSC does not finance its operations and the actual costs to finance AGSC assets include the short-term debt, long-term debt and common equity costs of AGL Resources ("AGLR"). Tr. 1947-48. This is consistent with the costs to finance Atlanta Gas Light operations, and PIAS witness Kollen's support of the use of AGLR consolidated debt costs as the debt costs for the Company supports this fact.

Atlanta Gas Light clearly would be allowed to earn a reasonable rate of return on the AGSC plant if it were owned directly by the Company. Witness Morley demonstrated that this business model provides clear cost-saving benefits to customers. Tr. 2025. Therefore, the legal structure of AGLR is not the relevant factor when determining the appropriate ratemaking treatment of AGSC plant. Further, ownership of the plant by AGSC should not disqualify it for inclusion in Atlanta Gas Light's rate base. The Commission is also persuaded that this treatment is consistent with the Commission's treatment of Atmos Energy Corporation. The Commission agrees with AGLC that the substance of the transaction is that AGSC net plant is used to provide utility service to AGLC Georgia customers and the form is that AGSC net plant is on the books and records of AGSC and not AGLC. Accordingly, AGSC plant should be included in rate base.

PIAS also asserts that the Company's estimate of AGSC plant is overstated. Tr. 1102- 03. The Commission makes no such finding. In addition, PIAS asserts that construction work in progress ("CWIP") should not be included in rate base since it accrues Allowance for Funds Used During Construction ("AFUDC") on CWIP. Tr. 1102-03. Mr. Morley testified that AGSC does not accrue AFUDC on CWIP. Tr. 1958. Based on the evidence provided by AGLC through testimony, workpapers and data requests, the Commission accepts AGLC's estimate of AGSC plant.

3. CIAC and Customer Deposits

Contributions in aid of construction ("CIAC") was represented by the Company as \$37,440,000. AGLC Exhibit No. 39 (MJM-4), Revised, Sch.1 Revised. No party challenged AGLC's CIAC figures nor its statement that customer deposits would reduce rate base by \$81,000. Accordingly, the Commission accepts AGLC's CIAC and customer deposit recommendations.

4. ADIT

AGLC's rate base for accumulated deferred income taxes ("ADIT") is \$449,621,000, AGLC Exhibit No. 39 (MJM-4) Sch.1 REVISED including ADIT associated with AGSC plant, AGLC's proposed Customer First programs, the impact of the proposed depreciation rates supported by AGLC witnesses Watson and Watts and the impact of bonus depreciation, the latter of which the Company included in its rebuttal testimony (AGLC Exhibit No. 118 (MJM-6) Sch. 2). The components of the Company's proposed ADIT are as follows:

Reference	Amount
AGLC Exhibit No. 39 (MJM-4) Revised, Schedule 1, Revised, Column 8, Line 6	436,366,305
AGLC Exhibit No. 39 (MJM-4) Revised, Schedule 1a, sum of lines 2-5	1,314,220
AGLC Exhibit No. 118 (MJM-6), Schedule 2 - Bonus Depreciation	11,729,000
Impact of correction to depreciation rate for general plant	211,000
Total Proposed Test Year ADIT	<u>49,620,525</u>

5 Depreciation Rates

Atlanta Gas Light Company provided testimony and supporting documents concerning a depreciation study performed on behalf of the Company by witnesses Watson and Watts. Witnesses Watson and Watts initially recommended depreciation rates that would produce an increase in annual depreciation expense of approximately \$7.97 million. Based on a transcription error pointed out by PIAS during cross examination, the witnesses modified their recommendation such that the annual increase in depreciation expense would be \$6.88 million. The primary forces driving the increase in annual depreciation were an increase in negative net salvage for Account 376, Mains from -8 percent to -11 percent and an increase in negative net

salvage for Account 380, Services from -11 percent to -50 percent based on recent experience and a return to traditional regulatory accounting principles.

PIAS presented the testimony of Mr. Dunkel, who performed an analysis of the Company's depreciation expenses. Mr. Dunkel presented total depreciation expense based on AGLC's proposed rate base as \$70,658,000, approximately \$8 million less than Mr. Watson's and Ms. Watts' recommended depreciation expense of \$79,079,000 (based on AGLC's recommended rate base) and about \$1.6 million less than existing depreciation rates. Mr. Dunkel raised four concerns with the depreciation rates recommended by the Company. Tr. 1306-07. Mr. Dunkel first argued that the Commission should continue using the current approved non-traditional net salvage method for Account 376, Mains and Account 380, Services, instead of adopting the traditional net salvage and removal cost method recommended by witnesses Watson and Watts. Tr. 1306. Mr. Dunkel then referenced the transcription error noted in the original cross examination of Mr. Watson and Ms. Watts. Tr. 1307. Third, Mr. Dunkel stated that Atlanta Gas Light Company's original recommendation charged depreciation expenses on fully depreciated accounts. (*Id.*). Finally, Mr. Dunkel contended that, in calculating depreciation expenses, AGLC incorrectly used functional depreciation rates instead of account-based rates. (*Id.*).

AGLC made the appropriate correction in its rebuttal testimony to account for the original transcription error. Tr. 2233-34. AGLC also removed any depreciation expenses for fully depreciated accounts. Tr. 2007. On the issue of account-based rates versus functional rates, witnesses Watson and Watts noted on rebuttal that it has been a long-standing practice of Atlanta Gas Light Company to use function-level depreciation rates for its actual depreciation expense calculation on its books and that the Commission has approved the Company's use of this practice in the past. Tr. 2266-67.

Mr. Dunkel used a different method for determining removal costs than those used by Mr. Watson and Ms. Watts. Mr. Dunkel testified that removal costs, i.e., negative salvage value should be accounted for separately from other aspects of depreciation rates based on financial accounting methodologies and a Federal Energy Regulatory Commission ("FERC") order regarding the treatment of certain removal costs for accounting purposes. Tr. 1313-14. On rebuttal, Mr. Watson and Ms. Watts testified that financial accounting rules and regulated utility accounting rules often differ and alleged that Mr. Dunkel's depreciation approach was not consistent with the regulatory accounting rules that AGLC must follow. Tr. 2249-51. Mr. Watson and Ms. Watts also noted on rebuttal that the depreciation method recommended by Mr. Dunkel for net salvage would fail to recover even the amount that the Company is now paying in removal costs, much less allow AGLC to accrue costs for future removal as required under FERC rules. Tr. 2235-36. During the AGLC's cross-examination of Mr. Dunkel and in the rebuttal testimony, it was noted that Mr. Dunkel's approach has been adopted by five states and the jurisdiction of the District of Columbia.

Whereas Mr. Watson's and Ms. Watts' traditional methodology allows the Company to both recover current removal costs and accrue for future costs of removal, Mr. Dunkel's approach places an inequitable burden on future generations to pay for the removal of pipes now in use by customers

on the system. This non-traditional approach by Mr. Dunkel may reduce depreciation rates but it is not consistent with regulatory ratemaking accounting rules. The Commission finds Mr. Watson's and Ms. Watts' traditional depreciation methodology to be reasonable and therefore we adopt Mr. Watson's and Ms. Watts' accounting methodology and depreciation rates with the exception of net salvage value for services, Account 380, to negative 30 percent.. The Company is directed to include a second adjustment in the next rate case to complete the financial portion of restoring the traditional methodology of calculating net salvage value. Based on the rate base we adopt herein, the depreciation expense shall be \$79,079,000 for Atlanta Gas Light plant and \$6,276,000 of depreciation expense allocated from AGL Service Company plant and included in O&M Expense.

6 Lead/Lag Adjustments

PIAS proposed a number of changes to the lead/lag study performed by AGLC witness DePriest. Specifically, PIAS recommended changes to the Company's recommended expense lead days for pension expenses, retirement savings plus plan expenses, franchise fees, and AGSC allocated expenses. Tr. 942-46. In addressing PIAS' recommendation to add 45 days to the expense lead days for AGSC allocated costs, AGLC witness Morley testified that PIAS' approach does not allow AGSC the opportunity to recover the true and accurate costs incurred in providing services to AGLC. Tr. 1977. AGLC witness DePriest addressed the PIAS' other recommended lead/lag recommendations, stating that the PIAS' recommendations are inconsistent with accepted ratemaking theory, indicate a misunderstanding of the facts surrounding certain expense leads, and do not take into consideration changes in AGLC's business practices. Tr. 2210-11. The Commission finds the lead/lag recommendations of Company witness DePriest to be reasonable. Consistent with the facts provided for AGSC plant in rate base, the operating costs of AGSC include short-term and long-term debt and common equity. Further, the expense lead proposed by PIAS does not recognize AGSC's actual expense lead and would not allow AGSC the recovery of its total costs incurred in providing utility service to AGLC customers. Therefore, the Commission agrees with AGLC witness Morley regarding the expense lead for AGSC allocated charges. The operating costs of AGSC include short-term and long-term debt and common equity.

7. Working Capital Requirements

Cash Working Capital varies with revenue requirements and should be adjusted to reflect changes in revenue requirements as determined by the Commission. AGLC proposed a reduction to rate base for its Working Capital Requirement in the amount of \$10,337,000. This amount includes \$10,321,000 initially proposed by the Company (AGLC Exhibit No. (MJM-4) Revised, Schedule 1 Revised) plus an additional \$16,000 included in AGLC's errata (AGLC Exhibit No. (MJM-4) Revised, Schedule 1a). This amount also includes \$33,980,000 based on the Lead/Lag study results (AGLC Exhibit. No. (MJM-4) Revised, Schedule 3, Page 1 Revised).

In AGLC's witness Morley's rebuttal testimony, the Working Capital Requirement was reduced by \$1,026,000 to incorporate a correction that reduced the lead/lag component by \$137,000 and adjustments that increased the lead/lag component by \$426,000. AGLC also included an increase in the net pension asset of \$737,000 (AGLC Exhibit. No. 118 (MJM-6) Schedule 2). The increase in the net pension asset is the result of additional pension contributions made during the test year. The resulting Working Capital Requirement proposed by the Company is \$9,310,000.

PIAS asserts that an allocable portion of AGSC's workers compensation and injuries and damages reserves should be included as a component of working capital as well. The Company contends that inclusion of these reserves would also require the inclusion of other rate base items, all of which combined together would have a minor impact to the Company's total rate base amount. Furthermore, the Company contends that expenses associated with these items are appropriately included in rate base through the lead/lag results. The Commission agrees with the Company on this issue and finds AGLC's adjusted Working Capital Requirement to be reasonable.

8. Rate Base Determination

Accordingly, the Commission finds that the rate base for Atlanta Gas Light Company for ratemaking purposes is \$1,312,822,870.

B. Cost of Capital

Determination of the weighted average cost of capital requires three steps: (1) adoption of an appropriate capital structure; (2) determination of the cost rates for debt and equity, the two components of the capital structure; and (3) application of these rates to the adopted capital structure to determine the weighted average cost of capital ("WACC"). In this case, there is disagreement between AGLC and the PIAS regarding the capital structure, the cost rate for debt, and the determination of the appropriate cost rate for common equity.

1. Capital Structure

Capital Structure refers to the relative portions of debt and equity that are reflected in the capital accounts of a company. The common equity ratio, which is expressed in percent and represents total common equity divided by total capitalization, is a summary measure of the capital structure. In this case, AGLC recommended that a capital structure of 4.37% Short-Term Debt, 44.63% Long-Term Debt, and 51% Common Equity. In addition, AGLC witness Hevert testified that AGLC's proposed equity ratio was reasonable and supported this capital structure in

AGLC Exhibit No. 51 (RBH-8) and AGLC Exhibit No. 109 (RBH-22). Tr. 1861.

PIAS witness Kollen testified that AGLC failed to address or justify its proposed increase in the common equity ratio to the recommended 51% presented by Atlanta Gas Light Company in this case. Tr. 958-59. PIAS witness Parcel also disagreed with AGLC's proposed capital structure, arguing that the AGLC's proposed capital structure is not consistent with past structures maintained by Atlanta Gas Light Company and that AGLC's proposed common equity ratio fell outside the range of the proxy group used by Mr. Parcel. Tr. 1265-66.

In his rebuttal testimony, AGLC's witness Hevert responded to the PIAS' arguments. Mr. Hevert stated that, in making his proxy calculation, Mr. Parcel ignored the typical financing cycle for natural gas utilities and selected a quarter for which much of the short term debt is used to finance current, rather than permanent assets. Tr. 1856. Mr. Hevert also stated that Mr. Parcel failed to review the capital structures of the individual utility operating companies and instead reviewed the consolidated capital structures for his proxy group. (*Id.*). The Commission agrees with AGLC on this issue and finds the analysis by Mr. Hevert to be reasonable.

The Commission finds that the evidence supports the capital structure recommended by AGLC and finds the methodologies used by the Company in determining its capital structure appropriate. The Commission finds that the appropriate capital structure upon which to authorize just and reasonable rates in this proceeding is as follows:

<u>Component</u>	<u>Ratio</u>
Short-Term Debt	4.37%
Long-Term Debt	44.63%
Common Equity	51.00%

2. Cost of Debt Capital

The cost of debt capital as testified to by AGLC witness Cave on rebuttal included cost rates of 2.17% for short-term debt, and 5.76% for long-term debt. (AGLC Exhibit. No. 123, (SC-7), Schedule 1).

PIAS witness Kollen disagreed with the initial cost rates for both long-term and short-term debt as originally filed by the Company. One of Mr. Kollen's primary arguments was that the 30-day forward curve for the London Inter-Bank Offering Rate ("LIBOR") on which AGLC had based its initial calculations had decreased since the Company's original filing. Tr. 962-63. AGLC witness Cave testified that it is appropriate to update LIBOR rates, whether they increase or decrease, and therefore AGLC reduced its initial long-term debt rate from 5.86% to 5.76% and its

short-term debt rate from 2.88% to 2.17%. (AGLC Exhibit. No. 123, (SC-7), Schedule 1).

Mr. Kollen also disagreed with a number of assumptions used by the Company to calculate its long-term debt rate. Tr. 960-64. Mr. Kollen disagreed with the Company's assumptions that AGL Resources would refinance its 7.125% \$300 million debt issuance in January 2011; that AGL Resources would not make an incremental debt issuance in the test year; and that certain letter of credit and remarketing fees associated with variable long-term debt instruments would increase. *Id.* Mr. Cave testified that AGLC would agree to update its costs to reflect PIAS' recommendation of an annualized methodology on this point. Tr. 2090. As to the incremental debt issuance, Mr. Cave testified that AGL Resources had no intention to make such an issuance within the test year and that AGLC's evidence in this case supports that conclusion. Tr. 2092-93. Mr. Cave also presented testimony supporting the Company's proposed fees and renewal of its letter of credit and remarketing fees associated with variable rate long-term debt instruments. Tr. 2101-05.

For short-term rates, Mr. Kollen disputed the Company's assumption that AGL Capital Corp. would renew its credit facility in September or October of 2010 as well as the related fees associated with that renewal. Tr. 965. Witness Cave testified that AGL Capital Corp. did in fact renew its credit facility on September 15, 2010 and that the fees associated with that renewal were consistent with those provided by the Company in its initial case. AGLC provided support for the renewal and the associated fees with its rebuttal testimony. Tr. 2109-12.

The Commission finds that Atlanta Gas Light Company provided adequate support for its test-year costs related to projected financing activities within that period. The Commission finds that it is appropriate to update debt costs at the time of rebuttal testimony preparation for more current information, whether rates have increased or decreased, and therefore finds that the short-term debt cost and long-term debt cost presented by witness Cave are reasonable.

3. Equity Capital

The Commission heard the expert testimony of two witnesses on the cost of common equity during the hearings in this matter. In its direct and rebuttal case, AGLC presented the testimony of Mr. Hevert. In responsive testimony, the PIAS presented the testimony of Mr. Parcel. Mr. Hevert initially recommended a return of 11.25%. Tr. 504. Mr. Hevert later revised his recommended return to 11.00%. Tr. 1764. Mr. Parcel recommended a return of 10.0% based on his recommended range of 9.5% to 10.5%. Tr. 1226.

The United States Supreme Court in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281 (1944) articulated the standards to be used in the determination of the cost of capital. The standards set forth in the *Hope* case are:

1. The allowed return on common equity should be the same as that earned on other investments of comparable risk;

2. Utilities have no constitutional right to profits realized by more speculative ventures;
3. The allowed return should be sufficient to maintain the utility's credit standing and enable it to raise necessary capital; and
4. A reasonable return may vary over time, reflecting changing economic conditions.

Although this Commission adheres to no particular theory or methodology for the determination of the cost of equity, it does test the various recommendations before it against these standards to determine the reasonableness of the approaches and recommendations of the parties. Thus, the Commission is able to fulfill its function of engaging in a careful analysis of the theories and methodologies presented to it for application in the regulatory environment.

Mr. Hevert testified that the determination of an appropriate return on equity ("ROE") requires the exercise of judgment, particularly when the assumptions underlying the financial models used to estimate the cost of equity do not fully conform to the behavior of capital markets. Tr. 504. Mr. Hevert employed three market-based methodologies designed to estimate the return required by investors on the common equity capital committed to Atlanta Gas Light Company. The three methodologies employed by Mr. Hevert were: (1) the Capital Asset Pricing Model ("CAPM"), (2) the Risk Premium approach, and (3) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow ("DCF") model. Tr. 505. Mr. Hevert noted that it is extremely important to consider the results of several analytical approaches in determining the appropriate ROE. (*Id.*) He also noted that such consideration must be tempered with due caution as to the results generated by each individual approach. Tr. 533.

In his direct testimony, Mr. Hevert summarized his results for the Constant Growth and Multi-Stage forms of the DCF model as follows:

	Mean Low	Mean	Mean High
Constant Growth			
DCF			
30-Day Average	8.29%	10.01%	11.48%

90-Day Average	8.29%	10.02%	11.48%
180-Day Average	8.39%	10.12%	11.58%
Multi-Stage DCF			
30-Day Average	10.39%	10.51%	10.62%
90-Day Average	10.40%	10.53%	10.65%
180-Day Average	10.51%	10.69%	10.87%

While Mr. Hevert calculated results for the CAPM, he did not give any specific weight to those results. Tr. 559. Mr. Hevert's Risk Premium approach calculations produced an ROE range of approximately 10.64% to 11.01%. Tr. 561. Based on these studies, Mr. Hevert testified in his direct testimony that AGLC's cost of capital should be set at 11.25%.

In arriving at his recommendation, Mr. Parcel utilized the Discounted Cash Flow, CAPM, and Comparable Earnings methodologies. Tr. 1226. Witness Parcel's results were as follows:

Methodology	Range
Discounted Cash Flow	9.0-10.0% (9.5% mid-point)
Capital Asset Pricing Model	7.6%

Comparable Earnings	10.8-12.1%
Adjusted Comparable Earnings	10.0-10.5% (10.25% mid-point)

In his rebuttal testimony, Mr. Hevert noted that market instability and investor risk aversion remain at comparatively high levels. Tr. 1763. As a result, he stated that some models used in his direct testimony now produce higher estimates of the Company's cost of equity while others, including the Constant Growth DCF model, produce lower estimates. Tr. 1764. Although Mr. Hevert testified that he believed that his initial recommendation remained valid, he stated that he recognized that this Commission has placed certain weight on the DCF model in the past. As a result, Mr. Hevert revised his cost of equity recommendation to 11.00%. Mr. Hevert also stated that no adjustment to his result was necessary based on investment risk relative to the industry. Tr. 1815.

Mr. Hevert also testified that he confirmed the reasonableness of his recommendation by comparing the market conditions in 2005 when the Commission agreed to a 10.9 ROE for Atlanta Gas Light Company to the market conditions existing today. Tr. 1886-90. He presented several measures of market risk and volatility from 2005 compared to current conditions and found that investors are much more risk adverse today compared to 2005. Accordingly, based on the market risk, he stated that investors require a greater return today than 2005 and that the current market data supports an increase to the 10.9% ROE awarded in 2005.

The Commission finds that an ROE of 10.75% is just and reasonable, and is supported by the evidence in this case. The Commission finds this ROE to be sufficient to maintain the financial integrity of the Company and to attract capital.

4. Weighted Average Cost of Capital

Combining the determinations made in the foregoing paragraphs of this Order, the overall rate of return on rate base for AGLC may be derived in percentages as computed below:

	Ratio	Cost Rate	Weighted Average Cost	Grossed-Up Cost
Long-Term Debt	44.63	5.67	2.53	2.53
Short-Term Debt	<u>4.37</u>	<u>2.17</u>	<u>0.09</u>	<u>0.09</u>
Total Debt	49.00		2.62	2.62
Common Equity	<u>51.00</u>	10.75	<u>5.48</u>	<u>8.94</u>
Total Capitalization	100%		8.10%	11.56%

C. Proposed Adjustments to Operations & Maintenance Expenses and Taxes Other Than Income

1. Operations and Maintenance Expense Before Adjustments

AGLC's projected operations and maintenance (O&M) expense for the test period ending May 31, 2011 is approximately \$214,799,000, including allocations from AGSC, as set forth in AGLC Exhibit No. 36 (MJM-1) Revised, Schedule 2 Revised. The Company increased this amount by \$957,000 to incorporate an increase in pension and other post retirement benefits and to adopt some of PIAS' proposed adjustments. Therefore, the Company's total O&M expense for the test year is \$215,756,000. AGLC witness Mr. Morley testified that the projected test year baseline O&M expense of \$187,573,000 is approximately \$3 million less than AGLC's actual O&M expense of \$190,557,000, after ratemaking adjustments, for the twelve months ended December 31, 2009. PIAS recommends adjustments that would result in a reduction of the Company's O&M expense by almost \$9 million. Tr. 947.

Based on a thorough analysis of the record, the Commission finds that AGLC's projected O&M expense is reasonable. The Commission adopts AGLC's projected O&M expense for the test period ending May 31, 2011 as modified by PIAS' adjustments noted below.

2. Acquisition Synergy Savings

AGLC proposed a 50/50 sharing of acquisition synergies. AGLC witness Steve Cave defined acquisition synergies to mean the cost savings that result from the provision of services from a service company—in this case, AGL Services Company—to multiple utilities and across multiple jurisdictions. Tr. 369. According to Mr. Cave, these savings occur when the parent company acquires an additional utility franchise, allowing overall costs to be spread among a larger asset base, thus reducing the allocations to each individual utility. (*Id.*). On rebuttal, AGLC witness Segal further described and recommended AGLC's specific proposal to

implement an acquisition savings 50/50 sharing policy for future acquisitions and the Company's proposal to share in the test year savings created by the prior acquisitions by AGL Resources of Virginia Natural Gas ("VNG") and NUI. Tr. 1543.

For future acquisitions of non-jurisdictional distribution companies, Mr. Segal recommended that demonstrated acquisition savings should be shared on a 50/50 basis for ten years, and that AGLC should have the right at that time to petition for an additional five years of savings. Tr. 1553. Under Mr. Segal's proposal, the Company would be required to demonstrate any realized net savings within two-years after the closing of an acquisition. Demonstrated net savings would then be shared with ratepayers through an interim surcredit, if a sharing period of at least ten years is adopted, until incorporated into rates in the next rate case. Tr. 1550. Mr. Segal stated that the AGLC's proposal for the sharing of future synergy savings is in the public interest because it is equitable and will increase the chances that transactions will be executed by AGL Resources, and will provide AGL Resources and AGLC with the proper incentive to maximize the synergies available from any such transactions. Tr. 1555.

PIAS witness Kollen objected to the Company's proposal regarding the sharing of future acquisition synergies on a number of grounds. Tr. 972-73. Mr. Kollen stated that the any expenses were "phantom" and not real expenses to the Company. Tr. 971-72. Mr. Kollen also disagreed with any pre-approval of future savings. Tr. 972. Mr. Kollen testified that AGL Resources did not need an incentive to make acquisitions and did not need additional incentives to make the VNG and NUI acquisitions. Mr. Kollen also testified that AGL Resources did not require regulatory certainty to acquire VNG and NUI and that AGLC should put forward a specific proposal for sharing future savings. (*Id.*).

On rebuttal, AGLC witness Segal addressed Mr. Kollen's concerns. Tr. 1544-53. Mr. Segal agreed with Mr. Kollen that AGLC should specify a specific sharing mechanism and provided the recommendation discussed above. Mr. Segal testified that this policy does not create risk for ratepayers, but assures that AGL Resources receives an equitable share of the savings it generates and has an incentive for increasing savings resulting from future acquisitions. Tr. 1548-49. Mr. Segal testified that the 50/50 sharing of current and future savings from an acquisition, for a period of 10 or 15 years, results in the customers receiving 62 to 69% of the net present value of the lifetime savings that result from the acquisition. Tr. 1623.

Applying the same 50/50 sharing ratio, Mr. Segal also recommended that the Commission adopt AGLC's proposal to share in the acquisition synergy saving created for AGLC by AGL Resources' acquisition of VNG and NUI, stating that AGL Resources has already shared a substantial portion of these savings with the ratepayers and that AGL Resources' shareholders should be allowed 50% of current and future savings on a going forward basis. Tr. 1560. Mr. Segal recommended that AGLC receive \$5.6 million related to the VNG merger for the next 5 years and \$8.8 million related to NUI for the next 10 years, with the right to petition this Commission to continue the NUI savings for an additional 5 years. Tr. 1561.

PIAS witness Kollen raised objections to the Company's proposal regarding the sharing

of future VNG and NUI savings. Tr. 970-72. Mr. Kollen testified that it is AGL Resources, not Atlanta Gas Light Company, that makes acquisitions. Tr. 970. Mr. Kollen also testified that AGL Resources and the AGLC do not recognize a need to gain the approval of this Commission for the acquisition of utilities that do not operate within the State of Georgia. (*Id.*). Mr. Kollen testified that AGLC opposed a sharing of the NUI savings in the prior rate case and that AGLC has requested similar treatment in prior rate cases before this Commission without success. (*Id.*). Mr. Kollen testified that any sharing should not be indefinite and that the proposal is a subsidization of AGL Resources. Tr. 971. Mr. Kollen testified that the proposal will result in an actual realized ROE above that authorized by the Commission and that no other AGL Resources affiliate receives such treatment. (*Id.*). Finally, Mr. Kollen testified that the savings that would be shown as an expense are not a cost of service and are not just and reasonable. Tr. 971-72.

Company witness Segal also responded to Mr. Kollen's testimony regarding the sharing of the current and future VNG and NUI savings. Mr. Segal testified that he does not agree that this Commission should have a role in the approval of non-jurisdictional acquisitions. Tr. 1545. Mr. Segal stated that the relevant factor for the Commission is its ability to review and approve the net savings to be shared. Mr. Segal next testified that any acquisition that benefits AGL Resources will also benefit AGLC through a reduction in the allocated cost of shared services. Tr. 1557-58. Finally, Mr. Segal testified that AGLC had already shared 100% of the NUI savings with the Company's ratepayers and that that had allowed AGLC to be able to agree to a 5-year stay out and avoid requests for rate increases during that period. Tr. 1560-64.

The Commission finds that it is appropriate to adopt a policy to encourage prudent acquisitions by the Company. For future mergers and acquisitions of non-jurisdictional distribution companies, the sharing of any net savings resulting from each of these transactions will be on a 50/50 basis between AGL Resources shareholders and the firm customers of AGLC. No net losses will be borne by AGLC customers. Atlanta Gas Light Company should make a showing to the Commission of its determination of net savings no later than 24 months following the legal close of any transaction, and based on the Commission's confirmation of these net savings. Demonstrated net savings will then be shared with ratepayers through an interim surcredit until incorporated into rates in the next rate case. The Company will issue interim monthly credits to firm customers so that their savings are shared immediately with ratepayers outside of a rate case proceeding. Sharing of these savings should extend for ten years from the date on which the savings begin to be shared.

The Commission finds this policy of ten years of sharing should also be used to determine any additional sharing of the Virginia Natural Gas (VNG) and NUI mergers. Since the VNG acquisition closed in October of 2000 and the Company began to produce savings from that transaction in 2001, no further sharing with the Company of those savings are appropriate. The Company will no longer recognize the sharing through its Grey Book accounting treatment. With the NUI acquisition, which still has five years to go under the 10 year policy, the Commission finds it is appropriate that the Company will share the \$17.6 million on a 25/75 basis between the AGLC shareholders and the AGLC ratepayers through December 2015.

3 Outside Services and Allocated AGSC Gas Operations and WMS Expense

PIAS witnesses Kollen and Wackerly contested the Company's proposal to increase the O&M expense starting January 1, 2011 over and above the 2010 budget expense amounts to include outside services costs associated with grounds maintenance and collection of certain regulator capacity information and AGSC allocated costs for an additional analyst to oversee the a meter accuracy program, and vendor training for new software systems. Tr. 949. Mr. Kollen and Mr. Wackerly argued that these adjustments should not be allowed because the expenses were not included in the 2010 budget or should have been amortized over three years as nonrecurring costs. Tr. 949-50. Company witness Reese testified that, in making its adjustments for these costs, Mr. Kollen and Mr. Wackerly used annualized costs for the elimination of AGSC allocated expenses instead of the five-month period used by the AGLC in its initial case. Tr. 2131. Ms. Reese also testified that all of the expenses challenged by Mr. Kollen and Mr. Wackerly were reasonable and that AGLC developed a process to predict costs that are expected to occur in 2011. Tr. 2132-33. Ms. Reese testified that, if AGLC applied an inflation factor to the 2010 budget, as was recommended by PIAS during the September 13 hearing, AGLC would have included an additional \$922,000 in costs for the five months ended May 2011, as opposed to the \$229,000 it determined based on the specifically identified 2011 cost increases. Tr. 2133. On the issue of non-recurring expenses, Ms. Reese testified that the impact to the Company's cost of service of including five months of expense versus a three year amortization to the total amount would be offset by the costs of adding another layer of accounting to track and record monthly journal entries, balance sheet review and reconciliation, and review of regulatory assets for financial reporting. Tr. 2137-38.

Based on the evidence presented, the Commission finds AGLC's proposed increase in expenses for 2011 to be reasonable.

4. Composite Ratio

PIAS asserts that 100% of Southstar/GNG's composite ratio formula should be included in the Composite Ratio instead of AGL Resources' ownership percentage in Southstar. Tr. 1106. AGLC witness Morley testified that, although AGL Resources is required under generally accepted accounting principles to include 100% of Southstar's assets, operating margin and operating expenses on its books and records, these amounts are offset elsewhere to properly report AGL Resources' 85% ownership interest in Southstar. Tr. 1997. Mr. Morley also stated that Southstar is much more decentralized than other AGL Resources affiliates and does not utilize AGSC services to the same extent as other AGSC affiliates. Tr. 2052-53. In addition, Mr. Morley also testified that, although the Company used a 75% ratio in its calculations (AGL Resources ownership interest in Southstar increased from 75% to 85% in January 2010), this difference is offset by the fact that the Company included AGL Networks ("AGLN") in the composite ratio, even though AGL Resources sold AGLN to a third party in June of 2010. Tr.

1999-2000. In contrast, PIAS included AGLN in its composite ratio when determining its proposed reduction to AGLC's allocated costs. Applying a consistent approach would have yielded a much lower adjustment than that proposed by PIAS. According to Mr. Morley, PIAS' adjustment would have been only \$34,000 had PIAS excluded AGLN from the composite ratio. Tr. 2001-01. The Commission finds the method used by the Company to calculate the Composite Ratio to be reasonable.

5. Federal and State Income Tax Expense

PIAS testified that AGLC incorrectly added AFUDC-equity to taxable income. Tr. 953. PIAS witness Kollen testified that AFUDC-equity is net of tax, unlike the AFUDC-debt component, which is before tax, and that, therefore, the Company's methodology includes the income tax expense on AFUDC-equity twice. (*Id.*). Company witness Morley testified that Mr. Kollen's recommendation is based on the assumption that AGLC uses a grossed-up, or debt and equity, pre-tax rate of return when calculating AFUDC for capitalization in its plant accounts. Mr. Morley testified that, to his knowledge, AGLC has never accrued AFUDC in the manner used in the PIAS' calculations. Tr. 1991-95. Further, Mr. Morley testified that Atlanta Gas Light Company uses the AGLC's authorized rate of return when accruing AFUDC to its plant accounts. Tr. 1957. The authorized rate of return consists of the debt pre-tax rate of return plus the equity after tax rate of return. This rate was provided in minimum filing requirement A-6. Mr. Morley also testified that the Company does not use the before tax equity rate of return when accruing AFUDC to its plant accounts. Tr. 2029-30; 2070-71. The Commission finds the evidence submitted by the Company on this issue to be reasonable.

6. Property Tax Expense

PIAS asserts that the test year property tax expense should be based on the plant balances as of December 31, 2010 as the Company's approach includes costs beyond the test year while failing to reflect a reduction in these costs after the end of the test year. Tr. 952-53. AGLC witness Morley testified that PIAS' approach was not consistent with PIAS' other related calculations, used inaccurate data, and continued to use an unsupported claim that the Company's rate base associated with base rates will decline over the next three years. Tr. 1987. Mr. Morley also testified that if PIAS used accurate information and consistent methodologies, PIAS' proposed adjustment would have been \$135,000 lower. Tr. 1990-91.

The Commission finds that the evidence in this case supports the methodology used by Atlanta Gas Light Company to be reasonable to calculate property tax expenses.

7. Modifications to Customer Care Center Allocations

PIAS witnesses Kollen and Wackerly disagreed with the Company's selection of allocation factors for costs associated with three specific departments within AGL Services Company's Customer Care Center. Tr. 1113-14.

First, PIAS did not believe that any costs should be allocated to Atlanta Gas Light for Department 6040 Credits and Collections MGT because PIAS believes the Company does not have any end-use customers. Tr. 1113. Company witness McIntyre testified that this department does perform certain functions for Atlanta Gas Light regarding the tracking of SONP data. Tr. 2169-70. Ms. McIntyre did recommend an adjustment in this department because the department direct charges 12% of its labor costs to Atlanta Gas Light. This adjustment resulted in a reduction to the Company's Customer Service expense of \$101,062.

PIAS also objected to the allocation of departments 6036 Customer Relations, 6019 Call Center Overhead, and 6045 Customer Services Technology using the factor of end-use customers instead of by call-volume. Tr. 1113. Company witness McIntyre testified that the PIAS had oversimplified the nature of the Customer Care Center by assuming that all of the services provided at the Center are directly related to call volume. Ms. McIntyre explained that the workload for the three departments in question are totally unrelated to the number of calls received at the Center. For example, the complaints handled by Department 6036 Customer Relations comes directly from the appropriate regulatory body, such as this Commission, or from utility executives, and is more closely related to the total number of end-users on a system and not call volume. Tr. 2166-67. Ms. McIntyre testified that the actual percentage of work for Department 6036 associated with Atlanta Gas Light is 63%, which is significantly higher than the call volume allocation of 18% recommended by PIAS. Tr. 2166.

The Commission finds that the Company has presented evidence sufficient to support its proposed allocation of the costs for the Customer Care Center, as modified in the testimony of Company witness McIntyre.

8. Non-Jurisdictional Expenses (Other than Marketing Service Provider Expenses)

PIAS recommended a \$210,000 adjustment to exclude certain expenses judged by the PIAS to be non-jurisdictional. Atlanta Gas Light Company witness Morley testified that AGLC inadvertently included certain non-jurisdictional costs in its costs of service. Tr. 2002-03. In total, the Company agreed that \$118,000 of the PIAS' \$210,000 adjustments could be viewed as non-jurisdictional and should be removed from the cost of service. Tr. 2003. Mr. Morley testified that the remaining \$92,000 represents jurisdictional expenses that should remain in the cost of service. (*Id.*). Based on the evidence presented, the Commission accepts the PIAS' recommendation as to the \$118,000 but agrees with AGLC to support the jurisdictional nature of the remaining \$92,000 in expenses.

9. Allocated Bad Debt and Credit Reporting

The PIAS recommended rejection of AGLC's proposal to increase the allocated AGSC customer accounting expense through the inclusion of bad debt and credit reporting expenses. Tr. 1111. The Company agrees with PIAS that this adjustment is appropriate. Tr. 2003-04. The Commission accepts the PIAS' and AGLC's recommendation to remove bad debt and credit reporting expense in the amount of \$49,000.

10. Allocated Expenses for Marketing Service Provider

PIAS proposed to exclude expenses associated with AGSC's marketing service provider in the amount of \$472,000 on the grounds that this Commission has traditionally excluded marketing and economic development expenses from the revenue requirement. Tr. 1111-12. PIAS also testified that AGLC's proposed allocation would result in the subsidization of marketers in the Atlanta Gas Light Company service territory and that AGSC marketing expenses should not be included for ratemaking purposes. Tr. 1112. AGLC proposes 50% inclusion of the costs associated with the Council for Responsible Energy ("CRE") and also agrees with the exclusion of \$21,000 associated with sponsorships but does not agree with the exclusion of the remainder of the costs. Tr. 1984. AGLC proposes a 50% inclusion of CRE costs because the CRE provides information to the public on how to be a more efficient user of energy by encouraging recycling, use of mass transportation, use of energy efficient appliances and the use of energy efficient devices. Tr. 2005. According to AGLC witness Morley, the remainder of the costs recommended for exclusion by PIAS is for research and analysis and seminars and conference fees which AGLC considers jurisdictional in nature. (*Id.*) In total, AGLC proposes a reduction in costs allocated to the marketing service provider of \$129,000.

The Commission agrees with the PIAS that certain costs allocated to the AGSC marketing service provider should be excluded. The Commission also finds, however, that it is

appropriate to include 50% of the costs associated with the CRE and to include costs associated with research and analysis and conference fees. The Commission therefore adopts the Company's proposal to reduce the costs allocated to the marketing service provider by \$129,000.

11. Variable Compensation

PIAS proposes to exclude \$3.19 million in long-term incentive ("LTI") plan compensation expenses on the grounds that the expenses are non-jurisdictional and should be allocated to shareholders. Tr. 947-48. This proposal would eliminate 100% of the LTI program from recovery through rates. AGLC witness Morley testified that the Company is only proposing a \$182,000 increase over the historic year, reflecting the fact that new personnel became eligible for AGLC's LTI plan. Tr. 1984. Mr. Morley further testified that the LTI expense is one component of Atlanta Gas Light Company's total compensation program and that a change in one of the components of the total compensation program would require a change to one or more of the other components to achieve a compensation structure that continues to compensate Atlanta Gas Light Company's employees at the 50th percentile level of the market compensation for such services. Tr. 1983-84. Mr. Morley also testified that a reduction in one component would result in an increase to another component, which, combined would have no impact to AGLC's compensation expense in the test year. Tr. 2068. Based on the foregoing, this Commission finds that the Company's use of the LTI plan as part of its overall compensation plan is appropriate.

12. Amortization of Rate Case Expenses

PIAS Witness Kollen recommended that the costs for this rate case be amortized over a five year period instead of the three-year period recommended by AGLC. Tr. 950-51. Company witness Morley testified that the AGLC's suggested three-year period is a conservative estimate of the time between rate cases and that the recent five-year stay-out is the only example over nearly 30 years in which five years passed between rate cases. Further, the current economic and financial environment in which Atlanta Gas Light Company operates indicates that it is more likely AGLC will file another rate case in three years or less as opposed to five years as supported by PIAS. Tr. 1985. The Commission agrees with AGLC that a three year amortization period for rate case expenses is a more realistic time period based on historic information and current economic conditions.

13. Pensions and Other Post Retirement Benefits ("OPEB" Expense)

In his rebuttal testimony, AGLC witness Morley proposed an increase in pension and OPEB expense of \$1,354,000. AGLC Exhibit No. 118 (MJM-6) Sch. 1. According to Mr. Morley, the basis for this increase was a decline in interest rates since AGLC's initial filing. Tr.

2013. Mr. Morley testified that an adjustment to reflect the impact of declining interest rates on pension and OPEB expense is consistent with the Company's update to its debt and equity costs, which also reflect the impact of lower interest rates resulting in lower debt and equity costs than when the Company initially filed its case. Tr. 2012-13.

Mr. Morley testified that as interest rates decrease, the amount of future obligations due by the pension and OPEB plans to retirees decreases. Tr. 2075-76. The interest component of the pension and OPEB expense then increases due to the substantially larger obligation. Mr. Morley compared this obligation to an increase in long-term debt, and when the principle amount due increases, the resulting expense increases as well. (Id.). Lastly, Mr. Morley testified that the increase in pension and OPEB expenses and test year contribution requirements are supported by the actuarial study performed by the Company's actuary, Mercer. Tr. 2079-80. The Commission accepts the adjustment proposed by witness Morley.

14. Bonus Depreciation Extension on Deferred Income Taxes

In his rebuttal testimony, Company witness Morley proposed an adjustment to include the impact of the bonus depreciation extension on deferred income taxes. Bonus depreciation is an additional amount of depreciation allowed above and beyond what would normally be allowed under enacted tax depreciation rates. The federal Economic Stimulus Act of 2008 provided for a 50% bonus depreciation deduction for eligible assets placed in service in 2008. This 50% deduction was extended into 2009 and then again recently into 2010. Capital projects eligible for bonus depreciation are allowed a deduction for 50% of the cost of the asset plus the normal tax depreciation rate allowed for that asset class. The normal tax depreciation rate is then applied to the asset after the application of the 50% bonus depreciation. Bonus depreciation accelerates depreciation expense for income tax purposes, which in turn increases the Company's rate base component for accumulated deferred income taxes. The increase in accumulated deferred income taxes reduces rate base, thereby reducing the Company's revenue requirement. The extension of bonus depreciation into 2010 resulted in a revenue requirement decrease of \$1.356 million from the Company's original estimated revenue deficiency of \$54.2 million.

D. Customer First Programs

AGLC included a total of 15 separate programs that are part of its 2010 Customer First business plan that will incur expenses during the test year. Atlanta Gas Light Company also noted that, although it is not seeking costs beyond the test year for the programs in this case, AGLC does seek an order from the Commission allowing Atlanta Gas Light Company to capitalize, as part of the new systems, the costs that would otherwise be expensed as incurred under generally accepted accounting principles Tr. 175. The Commission finds that Atlanta Gas Light Company is authorized to capitalize all costs incurred for information technology projects associated with the Customer First program. Costs that are to be capitalized include those costs associated with project activities that would normally be expensed as incurred, including but not

limited to feasibility studies and system requirement analyses and data conversion.

AGLC's case includes three programs that have been implemented or are in the process of implementation: (1) the in-sourcing of certain Customer Care Center functions from India to Riverdale; (2) the investment in automated meter reading ("AMR") meter technology and resulting elimination of outside service expenses; and (3) the Service Availability program. Tr. 93. The PIAS did not oppose the recovery of the costs of these programs that are included in the baseline revenue requirement with the exception of certain reductions in the AGSC Customer Care Call Center costs allocated to Atlanta Gas Light Company as discussed in Section I.C.7. Tr. 1115. The Commission finds the AGLC's proposed costs for these programs to be reasonable.

Three programs—Asset Compliance and Testing ("ACT"), Leak Survey, and Locates—are proposed to begin after the test year and have no revenue requirements in this proceeding.

The remaining programs are discussed below.

1 Customer Management Application ("CMA")

CMA is an information technology system which Atlanta Gas Light Company began to develop in 2006 as a first step to modernizing the legacy CIS information technology environment. The Commission finds that the Company's financial requirements for this program are appropriate to recover costs within the test year.

2. Distribution Integrity Management Program ("DIMP")

DIMP are the federal requirements that are the result of a federal rulemaking by the Pipeline and Hazardous Materials Safety Administration to amend the Federal Pipeline Safety regulations. Tr. 108. The PIAS agreed with the Company's costs for this program in the PIAS' recommendation for the recovery of costs in the incremental Customer First component of the revenue requirement. Tr. 1119. The Commission finds that the Company's financial requirements and underlying assumptions for this program are appropriate. The Company also identified WMS as necessary for compliance with DIMP. WMS is addressed in Section I.D.6.

3. Generation II Gatekeeper

The Generation II Gatekeeper program allocates a limited number of shut-off for nonpayment ("SONP") orders that Atlanta Gas Light Company will accept on any given day among all marketers based on each marketer's market share. Tr. 123. AGLC proposes to enhance this program to increase the Gatekeeper capacity to allow up to 13,000 additional annual SONP orders to be accepted into the Gatekeeper system and to complete up to 12,000 increased reconnects/turn-on orders associated with the increased SONP orders beginning the

first quarter of 2011. Tr. 124. AGLC would also create a SONP “SpeedPass” program, expected to begin in 2012, that will ensure next business day service for up to 30% of SONP requests submitted. Tr. 125.

The PIAS testified that the annualized revenues from the reconnect fees that will be generated from working more SONPs should be included as an offset to the annualized costs. Tr. 1119. The Company agreed that it should update its revenue forecasts to account for the additional reconnections but disagreed with the PIAS’ proposed adjustment. Tr. 2307. While the PIAS recommended making an adjustment to account for an additional 12,000 reconnects (\$300,000), Company witness Buchanan testified that this annualized number is not appropriate because Atlanta Gas Light Company will only receive the additional reconnection revenue for the last five months of the test year. Tr. 2307-08. AGLC therefore increased its test year forecast by 5,000 reconnects and \$125,000 to account for the increased number of reconnects and associated revenues for the 5 months from January 2011 through May 2011. Tr. 2308.

During the hearings, a number of intervening marketers raised concerns regarding the number of days	Qualified Business Days	Daily SONPs	Add. Annual SONPs	New Employees	Cost (millions)
As filed	5	1,800	13,000	9	\$.920
Double G2G	5	1,800	26,000	18	\$1.840
Reduce Target Days by 1 Business Day	4	1,800	0	29	\$2.6

Reduce Target Days by 2 Business Days	3	1,800	0	58	\$5.2

The Commission finds that it is appropriate to approve AGLC's Generation II Gatekeeper program and to require AGLC to further expand the scope of the Generation II Gatekeeper Program. AGLC is directed to make the investments necessary to increase the proposed Generatopm II Gatekeeper service level from the proposed up to 25 percent increase in services to up to 50 percent annual increase requested by marketers in this proceeding. The Company is further directed to make the investments to fund the order fulfillment improvements requested by marketers allowing the Company to move toward providing key marketer services within a three qualified business day performance period and make a corresponding number of SONP reconnections as requested within a corresponding three qualified business day period based on the information provided by the company.

This docket did not include a rulemaking to alter the Company's performance standards, and the Commission must go through the proper steps to make any changes to those current standards. The Company does need time to make the investment in both the people and the resources requested and obtain actual field data to determine how it can most efficiently provide it.

The Commission shall issue a Notice of Proposed Rulemaking (NOPR) on or after July of 2012 to alter the Company's performance standards. AGLC's officers have stated clearly that they will make a best efforts commitment toward achieving these improved three qualified business day order fulfillments for customer SONPs and three qualified business day order fulfillment for customer turn-ons and turn-offs, reconnections upon the conclusion of the hiring and training of these employees that will be needed to make this process work.

Until the NOPR is issued, the Company will report its progress to the Commission for attaining a three qualified business day order fulfillment beginning on September 2011 for the period ending June 30, 2011, and make subsequent reports no later than 60 days following the close of each calendar quarter thereafter.

4. Marketer Interface Application ("MIA")

AGLC has proposed to continue to provide further enhancements to its MIA system,

which is the customer service functionality within the EnerAct system currently used by marketers. Tr. 128-29. The PIAS did not recommend any adjustments to the AGLC's proposed costs for this program. Tr. 1121. The Commission finds that the Company's financial requirements and underlying assumptions for this program are appropriate to recover projected costs within the test year.

5. Support Welding and Tapping ("SWAT")

The SWAT program is AGLC's emergency response group related to large diameter and high pressure pipe. AGLC proposed to increase the number of SWAT personnel after the end of the test year but also requests \$0.084 million for depreciation expenses and \$0.407 in the rate base in the test year. Tr. 1121. PIAS did not recommend any adjustments to AGLC's proposed costs for this program. (Id.). The Commission finds that AGLC's financial requirements and underlying assumptions for this program are appropriate to recover projected costs within the test year. **Work Management System ("WMS")**

AGLC's Work Management System is an information technology application that provides logistics, safety compliance, construction and invoicing of all below ground distribution work. Tr. 106; AGLC Exhibit No. 10 (WMS-1 Revised). The Company proposes to implement upgrades to the WMS to provide application updates that extend vendor support, add new functionality such as real-time mobile updates, and provide a future application platform for all field service. Tr. 107. The PIAS supports this program but testified that discretionary costs incurred to enhance an application to achieve efficiency and productivity gains should be offset by savings of at least an equivalent amount. Tr. 1121. On rebuttal, AGLC witnesses Lindsey and Cogburn noted that WMS is not discretionary but is instead necessary to be in compliance with federal safety regulations. Tr. 1637. With regard to PIAS' testimony that WMS will increase productivity and efficiency, Mr. Lindsey and Mr. Cogburn testified that WMS increases work requirements and complexity to the current process.

PIAS also testified to not allow CWIP associated with WMS as a component of rate base. AGLC witness Morley testified that AGLC does not accrue AFUDC on information technology projects. Tr. 2008-09; 2070-71.

Based on the evidence before it, the Commission finds that the Company's financial requirements, including rate base treatment for the WMS CWIP, and underlying assumptions for this program are appropriate to recover projected costs within the test year.

6. Pressure Control

AGLC intends to increase the number of employees performing Pressure Control responsibilities by 6 in the test year and by 22 over the next three years. Tr. 114-21. Pressure control personnel are the Company's subject matter experts who are responsible for inspecting,

troubleshooting, and maintaining the Company's 4,425 district and city gate stations and emergency valves. Tr. 116. This work has been increased through agreements entered into between the Company and this Commission's pipeline safety staff. Tr. 117. The Company states that its primary concern is building its existing pressure control workforce because 22% of AGLC's existing pressure control employees are currently eligible for retirement with 13% more employees becoming eligible in less than 4 years. Tr. 119-20.

PIAS witnesses Kollen and Wackerly testified that AGLC had not justified the need for an increase in pressure control personnel. Tr. 1123. The PIAS witnesses testified that the Company's concerns regarding an aging workforce were exaggerated and that Atlanta Gas Light Company's current staffing structure is sufficient. Tr. 1122-23. In rebuttal, AGLC's witnesses Lindsey and Cogburn submitted additional evidence demonstrating the increased workload for the pressure control personnel over the past five years and in support of AGLC's claim that additional personnel are necessary to meet safety requirements. Tr. 1639-40. Mr. Lindsey and Mr. Cogburn also presented evidence in support of the Company's concerns with an aging workforce including Industry publications and a NARUC resolution discussing the need to address the "Greying of the workforce." Tr. 1641-45.

The Commission finds that the Company's request is reasonable regarding the need to increase staffing for its pressure control functions and that the Company's financial requirements and underlying assumptions for this program are appropriate to recover projected costs within the test year.

8. Customer Compliance First Program ("CCF")

The Company's CCF program is designed to provide enhanced safety and address attrition on AGLC's system. The program allows the Company to provide more repair service capabilities so that its service personnel can assist customers that would otherwise have to be left without gas service due to appliance or equipment repair issues. Tr. 134. In addition, where the necessary repair cannot be made by the Company's service personnel, the CCF program would provide service vouchers or appliance replacement vouchers to the customer to assist in having the safety issue remedied and remain on Atlanta Gas Light Company's system. (Id.). As to safety, AGLC noted that, when its service technicians are forced to leave a danger card on an appliance that is not up to code, there is a substantial risk that the customer or another unqualified person will attempt to relight the appliance in an un-safe manner.

PIAS witnesses Kollen and Wackerly testified that the program cannot realistically be considered a safety program unless this Commission determines that customers will not repair their appliances themselves without subsidies from all other Atlanta Gas Light Company customers. Tr. 1125. Mr. Kollen and Mr. Wackerly also opposed the program on the grounds that it does not provide an adequate return on investment and that the program will result in the subsidization of the Company's unregulated affiliate, UtiliPRO. Tr. 1126.

In response to PIAS' position regarding safety, Company witnesses Lindsey and Cogburn noted the dramatic increase in danger cards left by the Company from 2008 to 2009. Tr. 1647. Mr. Lindsey and Mr. Cogburn testified that leaving a customer's gas turned off creates a potentially critical situation where the customer may seek unqualified personnel to activate gas service or repair their appliances. (Id.). Mr. Lindsey also provided recent examples of customers' issues caused by customers relighting appliances after danger cards have been left. Tr. 1674-75. Mr. Lindsey and Mr. Cogburn also testified that this program was not designed in coordination with UtiliPRO. Tr. 190. Finally, on the issue of economic return, Company Witness Buchanan noted that the customer retention benefits of this program, along with the energySMART program discussed below, are forecasted to result in approximately \$1 million in additional revenue that will continue each year for as long as the customers remains on the Atlanta Gas Light Company's system. Tr. 2312. This would result in an estimated payback of the costs for both programs of 12 years. (Id.).

The Commission finds that it is appropriate to the In-Home Repair program as proposed by AGLC, but declines to approve the Customer Compliance First Repair or Replacement Voucher program. The Commission has reduced the funding requested by AGLC for these voucher programs from the additional revenue requirement approved in this proceeding.

9. energySMART®

The Company's proposed energySMART® program is designed to address part of the attrition issue the Company is experiencing by providing incentives to gas customers and potential infill customers located on the Company's existing mains for the purchase of efficient natural gas appliances so that those customers will be less likely to switch to another fuel source. Tr. 143-44. PIAS witnesses Kollen and Wackerly objected to the inclusion of the costs of this program for a number of reasons, including that it is a discretionary, non-cost-effective, program that it could result in the further erosion of gas sales due to the use of more efficient appliances, and that the program results in a wealth transfer. Tr. 1128. As discussed above, Company witness Buchanan noted that this program would slow customer attrition and result in an acceptable return on investment. Tr. 2312.

The Commission determines that it will not approve the additional funding requested for the energySMART® rebate program. The Commission has reduced the funding requested by AGLC for the energySMART® program from the additional revenue approved in this proceeding.

E Net Operating Income for Ratemaking

Company witness Buchanan presented the Company's revenue forecast for transportation revenue and service fees and other revenues.

Projected transportation revenue was derived from Atlanta Gas Light's billing unit forecast for the various customer classes. AGLC forecasts a net loss in residential customers of 1.47% over the 17 month period from the 2009 historic period through the test year ending May 2011. Tr. 287. Company witness Buchanan testified that the average number of residential customers on AGLC's system has declined for the last two years and that economic forecasts and housing start estimates indicate that these underlying conditions will remain relatively consistent with current status through the test year, with some recovery beginning late 2011. (Id.). Mr. Buchanan testified that Commercial customers for the test year are projected to grow by 438 customers (or 0.47%) to 94,519 in calendar year 2010 and decline by 994 customers (or 1.05%) to 93,525 in calendar year 2011. Tr. 288. These changes result in 0.0% growth over the 17 month period from the 2009 historic period through the test year ending May 2011. (Id.). PIAS witnesses Thebert and Solganick testified that, while the PIAS had some concerns regarding the level of documentation provided by the Company, the PIAS is satisfied that the Company's growth adjustments and usage appear reasonable and recommended acceptance as modified to remove the billing units and revenue associated with Customer Compliance First and energySMART programs. Tr. 1378-79.

The Commission finds that the Company has provided sufficient detail to support its forecast in this proceeding and that the Company's evidence is convincing. Therefore, the Commission adopts AGLC's forecast of \$423,722,000 in jurisdictional revenue based on its current rates. AGLC Exhibit No. 132 (PGB 11).

F Revenue Deficiency/Excess

The Commission finds a revenue deficiency of \$26,557,218 based on the determinations herein, calculated as follows:

Rate Base	\$1,312,822,870
Weighted Average Cost of Capital	8.10%
Operating Income Required	\$106,338,652
Operating Income Available	\$90,055,235
Operating Income Deficiency	\$16,283,417
Income Expansion Factor	61.32%
Additional Revenue Required	\$26,557,218

II. COST ALLOCATION AND RATE DESIGN

A. Cost of Service Study

AGLC presented a cost of service study ("COSS") performed by David Heintz for the test year period, AGLC Exhibit No. 60 (DAH-1 Revised), that shows the Company's total jurisdictional cost to be used for ratemaking purposes divided among seven rate classes, peaking service, meter reading and reconnections/turn-ons/meter sets.

This cost of service study demonstrates that the rate of return for the residential class is approximately 4.3% for the test year, significantly lower than the overall rate of return to the Company as a whole of 6.0%, with all other classes of service providing a rate of return significantly above the overall rate of return. Tr. 763.

The Commission concurs with Mr. Heintz that the COSS should measure the cost caused by various customer classes and services and that non-cost factors should be considered in the rate design phase. The Commission concludes that the cost of service study presented by witness Heintz is a reasonable indication of the costs caused by various customer classes and services.

B Rate Design Issues

The Company is proposing two changes to its general rate design. The PIAS also recommends the consideration of a Certificated Marketer Support class.

1. Changes to AG-1 Rates

Atlanta Gas Light Company is proposing to reduce rates for the Agricultural customer class ("AG-1") by 20% in order to move toward a more neutral level of revenue recovery between AG-1 rates and those of the Commercial G-11 rates for qualifying customers. Tr. 295-96. The PIAS recommends that the Commission accept the Company's proposed structure for the AG-1 class. The Commission finds the proposed change to the AG-1 Rate Schedule to be reasonable.

2. Changes to Commercial Rates

For the Commercial class, the Company is proposing to change the number of levels of customer chargers to distinguish Commercial customers by level of DDDC. Tr. 296. Currently, the only such distinction is between customers whose DDDC is less than 2.5 DDDC and those customers with a DDDC of greater than or equal to 2.5. (*Id.*). Company witness Buchanan, however, testified that 90% of AGLC's customers in the Commercial Class have a DDDC factor

below 20. The Company proposes to further differentiate the Customer Charge at the following DDDC levels:

Range	Customers	Current	Proposed
		Charge	Charge
0 to 2.5	53,753	\$20.39	\$20
2.5 to 7	23,505	\$40.78	\$40
7 to 20	10,289	\$40.78	\$45
20 to 200	6,360	\$40.78	\$75
> 200	177	\$40.78	\$175

The proposed Commercial rate design provides a move toward equalizing the value of AGLC's gas delivery service to Commercial customers based on size of customer. Tr. 298. The PIAS recommends that this Commission accept the Company's proposed changes to the Commercial Customer Charge. The Commission finds the proposed changes to the Commercial Customer Charge to be reasonable.

3 Proposed Certified Marketer Support Class

The PIAS recommends that the Company be required to add an additional class to its COSS for Certificated Marketer Support. Tr. 1383. According to PIAS witnesses Thebert and Solganick, Atlanta Gas Light Company should be required to add this additional class because the Company is proposing a number of initiatives to provide services that are focused on the Certificated Marketers and therefore the costs for providing these services should be analyzed within a COSS to determine if that class is appropriately supporting its costs of service. (*Id.*).

The Company recommends that the Commission reject PIAS' proposal to require the

addition of a Certificated Marketer Support class. Tr. 2315. Company witness Buchanan based the Company's rejection of this proposal on two principles. First, Atlanta Gas Light Company provides delivery service to end-use consumers, and all of the activities described in the Company's case are for the provision of this service. (*Id.*). Although costs are recovered from marketers, those costs are billed as pass-through charges directly to end-use customers. Therefore, there are no services provided directly to marketers and no base revenues provided directly by marketers without a corresponding pass through charge to the end-use customer. (*Id.*). Second, PIAS' recommendation to recover certain program costs through an increase in turn-on and reconnect charges results in an increased financial barrier to customers who wish to obtain gas service to their homes or businesses or to restore their service after it has been cut-off. Tr. 2316.

The Commission finds that because Certificated Marketer Support does not supply revenues that are not pass through charges collected from end-use customers, it is not appropriate to allocate costs to a Certificated Marketer Support class. The Commission therefore rejects PIAS' recommendation to require that AGLC add a Certificated Marketer Support class. The Commission also finds that the current turn-on and reconnect charge rates of \$25 continue to be appropriate at this time.

C Allocation of Rate Increase to Customer Classes

As mentioned above, the Company has proposed to allocate the Company's revenue requirement in a way that would produce a modest move toward rate parity among the customer classes. According to Mr. Buchanan, Commercial customers make up 6% of all customers, but contribute 24% of the Company's total base customer charge and DDDC revenues. Tr. 297. Mr. Buchanan testified that the Company's proposed changes in the rate design will provide a gradual move toward rate parity between the Commercial and Residential customer classes. PIAS recommended a reduction in base rates and that, with the exception the proposed changes for the Agricultural class, the decrease be allocated "across the board" on a revenue basis. Tr. 1385. The Commission adopts the Company's recommendation of a modest move toward parity.

III. TARIFF ISSUES

A. Low Income Senior Citizen Discount

In his direct testimony, Company witness Buchanan proposed a modification to the Social Responsibility Cost ("SRC") Rider to allow the Company to recover the full discount given to qualifying low income senior citizens through the SRC rider. Tr. 302-03. Currently AGLC provides a discount to qualifying low income senior citizens in an amount up to \$14 per

month but is only authorized to recover \$10.50 of the discount for customers whose income level is below \$12,000 per year. Tr. 303.

PIAS witnesses Thebert and Solganick did not oppose AGLC receiving full recovery for the Senior Discount but were concerned that, as originally proposed in the tariff, the Company will recover \$14 for each qualifying customer, regardless of those customer's actual base charges. Tr. 1390. The Company agreed with PIAS recommendation to modify the tariff language to allow for the recovery of the actual amount of the Senior Discount, without over-or under-recovery. Tr. 2317.

Witnesses Thebert and Solganick also recommended that the Company establish an audit process to validate the eligibility of customers currently receiving the Senior Discount. Tr. 1392-93. In addition, Ms. Thebert and Mr. Solganick discussed the possibility of funding the Senior Discount through a supplement from the Universal Service Fund ("USF"). Tr. 1394.

It is the Company's position that an audit of this particular group of customers is unnecessary and will require additional cost to perform. Tr. 2320. Company witness Buchanan noted that while AGLC estimates that approximately 66,000 customers in the Company's territory are eligible for the discount, only about 38,000 customers actually receive the discount. (*Id.*). The Commission finds that the evidence presented in this case does support the need for an audit of this particular group of customers at this time and approves the Company's generic tariff language that allows for recovery of audit costs through the SRC Rider.

Company Witness Buchanan testified that AGLC supports offsetting the recovery of the Senior Discount through the use of the USF. Tr. 2319. The Company also proposed tariff language in the SRC Rider to include a provision for the SRC rate to be adjusted to incorporate supplemental funds to offset the rider rate. (*Id.*). The Commission finds that it is appropriate to utilize the USF to supplement the Senior Discount and to approve the tariff language as recommended by the Company.

AGLC currently serves approximately 38,000 senior citizens who received the \$14.00 per month Social Responsibility Cost ("SRC") senior citizen discount. At the current level of service, AGLC estimates that \$532,000 per month would be required from the Universal Service Fund ("USF") to fully compensate the Company for providing the discount, or an estimate of approximately \$7,448,000 for the period November 2010 through December 2011. Under the provisions of this order, the Commission shall pre-authorize a monthly disbursement of \$532,000 from the USF to the Company to be applied toward the actual cost of the program from November 2010 through December 2011.

Since AGLC calculates the number of participating senior citizens on the 20th of the month prior to the month of service, a USF disbursement authorization letter shall be mailed to the bank by the 10th day of the month of service for the \$532,000 disbursement to take place on the 15th of that month. AGLC will apply the \$532,000 to the service month's SRC discount for

senior citizens.

AGLC shall continue to file a monthly "SRC Rate Calculation" in Docket No. 31647 to the Commission by the end of the month prior to the service month. The monthly report shall detail the total amount of the Low Income Senior Citizen Discount, Audit Costs (if applicable), any prior month adjustments to date, and the total amount of USF funds required to offset the discount and audit costs (if applicable). The monthly report shall also track the difference between the total amount of USF funds required and the \$532,000 monthly disbursement.

No later than December 1, 2011, AGLC shall file a "Comprehensive True-Up Report" for the period ending December 2011 to provide a total true-up of disbursed funds. Any amount of unused USF funds will be returned to the USF within 30-days of the acceptance of the report filed report unless the Commission decides to continue with the USF funding of the SRC. Any funds that are under-collected shall be reimbursed to AGLC within 30-days of the acceptance of the report. If the Commission, by Order, decides to continue with the USF funding of the SRC, the reimbursement of the true-up under-collected amount will be included with the next month's funding disbursement.

B Additional Proposals for Tariff Changes

The Company proposed tariff revisions to delete references to the Annual Transition Rate Mechanism Charge and to delete references concerning the Valdosta Pool as a peaking pool, as presented in redlined format in MFR 1-4 REVISED of AGLC Exhibit No. 41 (MJM-6 Revised). PIAS recommends approval of these tariff revisions. Tr. 1394-95. Further, PIAS recommends this Commission require AGLC and PIAS to discuss tariff sheets Rule 10, Rule 13, and Rule 17, and, if necessary, present any modifications to the Commission for consideration. Tr. 1395-96. PIAS also recommends that this Commission require AGLC to file its "Gas Consumption Bulletin" and its updated Unit Cost of Certain Mains and Services at least every five years, or more frequently, as needed. Tr. 1396. The Company does not oppose these recommendations. Tr. 2321-22. The Commission approves these proposed revisions and directs AGLC to file revised tariff sheets reflecting such changes.

The Company also puts forth tariff changes reflecting the revised rates and rate design necessary to recover AGLC's proposed rate increase. The PIAS has proposed a decrease in rates and that, generally, the decrease should be made in the DDDC Charge rate while keeping the Customer Charge the same as current. In proposing a rate increase, the Company recommends that the increase should be applied to the Customer Charge first, and the recovery of the residual requirement for the class should be through an adjustment to the DDDC charge.

The Commission finds a rate increase to be reasonable and that the increase should be applied as recommended by the Company.

SUMMARY OF FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact

The Commission finds as a matter of fact that the test period to be utilized in resolving this matter is the twelve month period ending May 31, 2011.

2.

The Commission finds as a matter of fact that the appropriate rate base for the test period is \$1,312,822,870.

3.

The Commission finds as a matter of fact that the appropriate and just reasonable return on common equity for the Company is 10.75%. The Commission further finds that the appropriate cost of long-term debt is 5.67% and the appropriate cost of short term debt is 2.17%. The Commission further finds that the appropriate capital structure is 51% common equity, 44.63% long term debt and 4.37% short term debt. This is appropriate as the Company has used the same methodology in 2005, which has been updated based on current market conditions. The Commission further finds that the appropriate overall return is 8.10%, which when grossed up by the expansion factor is 11.56%

4.

The Commission finds as a matter of fact that the Company's required operating income is \$90,055,235.

5.

The Commission finds as a matter of fact that the appropriate total revenue increase for the Company is \$26,557,218, as shown in more detail in the Revised Compliance Schedules for Customer First Rate Case filed by the Company on November 1, 2010. The Company's revenue requirement includes all of the authorized revenues for the Company's base case adjustments; adjustments recommended by the PIAS that were incorporated in the Company's proposed order; the Company's Customer First program, as modified in this order; the Company's acquisition synergies sharing policy, as modified in this order; and, the Company's return to a traditional depreciation methodology.

6.

The Commission finds as a matter of fact that the Company's proposed rate design

should be approved.

7.

The Commission finds that the Company is authorized to capitalize all costs incurred for the information technology projects associated with Customer First. Costs that are to be capitalized include those costs associated with project activities that would normally be expensed as incurred, including but not limited to feasibility studies and system requirement analyses and data conversion.

8.

The Commission finds as a matter of fact that it is appropriate to restore the traditional method for calculating net salvage to avoid deferring costs to future customers. The Commission finds that it is appropriate to phase in the revenue requirement necessary to make this conversion over two rate cases. In this case, the Commission shall change the net salvage value for services, Account 380, to negative 30 percent. The Commission directs the Company to include a second adjustment in the next rate case to complete the financial portion of restoring the traditional methodology of calculating net salvage value.

9.

The Commission finds that it is appropriate to adopt a policy to encourage prudent acquisitions by the Company. For future mergers and acquisitions of non-jurisdictional distribution companies, the sharing of any net savings resulting from each of these transactions will be on a 50/50 basis between AGL Resources shareholders and the firm customers of AGLC. No net losses will be borne by AGLC customers. Atlanta Gas Light Company should make a showing to the Commission of its determination of net savings no later than 24 months following the legal close of any transaction, and based on the Commission's confirmation of these net savings. Demonstrated net savings will then be shared with ratepayers through an interim surcredit until incorporated in the next rate case. The Company will issue interim monthly credits to firm customers so that their savings are shared immediately with ratepayers outside of a rate case proceeding. Sharing of these savings should extend for ten years from the date on which the savings begin to be shared.

10.

The Commission finds this policy of ten years of sharing should also be used to determine any additional sharing of the Virginia Natural Gas (VNG) and NUI mergers. Since the VNG acquisition closed in October of 2000 and the Company began to produce savings from that transaction in 2001, no further sharing with the Company of those savings are appropriate. The Company will no longer recognize the sharing through its Grey Book accounting treatment. With the NUI acquisition, which still has five years to go under the 10 year policy, the Commission finds it is appropriate that the Company will share the \$17.6 million on a 25/75

basis between the Company shareholders and the Company's ratepayers through December 2015.

11.

The Commission finds that it is appropriate to approve portions of the Company's proposed Customer First Business Plan. The Commission reduces the revenue request from \$13.3 million to \$9.5 million by removing additional funding for energySMART® rebate and the Customer Compliance First voucher program. The Commission, however, does approve the Customer Compliance First in-home repair program.

Included in the \$9.5 million is an expanded level of SONPs from the Generation II Gatekeeper program, and an expedited order fulfillment program. AGLC is directed to make the investments necessary to increase the proposed Generation II Gatekeeper service level from the proposed up to 25 percent increase in services up to 50 percent annual increase requested by marketers in this proceeding. The Company is further directed to make the investments to fund the order fulfillment improvements requested by marketers allowing the Company to move toward providing key marketer services within a three qualified business day performance period and make a corresponding number of SONP reconnections as requested within a corresponding three qualified business day period based on the information provided by the company.

This docket did not include a rulemaking to alter the Company's performance standards, and the Commission must go through the proper steps to make any changes to those current standards. The Company does need time to make the investment in both the people and the resources requested and obtain actual field data to determine how it can most efficiently provide it. The Commission shall issue a Notice of Proposed Rulemaking (NOPR) on or after July of 2012 to alter the Company's performance standards. AGLC's officers have stated clearly that they will make a best efforts commitment toward achieving these improved three qualified business day order fulfillments for customer SONPs and three qualified business day order fulfillment for customer turn-ons and turn-offs, reconnections upon the conclusion of the hiring and training of these employees that will be needed to make this process work.

Until the NOPR is issued, the Company will report its progress for attaining a three qualified business day order fulfillment beginning on September 2011 for the period ending June 30, 2011, and make subsequent reports no later than 60 days following the close of each calendar quarter thereafter.

12.

The Commission finds it appropriate to modify the Company's Social Responsibility Rider as proposed by the Company to continue to provide a discount to low income seniors, and apply sufficient funds by refund from the Universal Service Fund (USF) to fully cover the cost of providing this discount. Use of USF funds will begin in November 2010 and shall be authorized

for calendar year 2011. The Commission will retain jurisdiction over this to decide whether to extend this for any additional periods. The Commission finds that such a refund from the USF is equitable.

The Commission directs the Company to work with the Commission Staff to develop an appropriate means to audit participation in the discount program, both to periodically verify that customers receiving the discount remain eligible and to identify eligible customers that are not receiving the discount. The costs of the audit and customer outreach, which have been estimated in the range of fifty thousand to seventy-five thousand dollars, would also be authorized program expenses recoverable under the SRC rider.

CONCLUSIONS OF LAW

1.

O.C.G.A. § 46-2-20(a) provides that the Commission has general supervisory authority over gas companies.

2.

O.C.G.A. § 46-2-23 provides that the Commission has exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm or corporation subject to its jurisdiction. The rates for firm distribution service and ancillary services rendered by an electing distribution company must be established in accordance with Article 5 of Title 46, O.C.G.A. §§ 46-4-151 *et seq.*

3.

O.C.G.A. § 46-2-25 provides in pertinent part that whenever any new rate schedule is filed, the Commission shall have authority, upon reasonable notice to the utility, to enter a hearing concerning the lawfulness of such rate, charge, classification, or service.

4.

O.C.G.A. § 46-2-26.4 provides for the accounting treatments to be used in any proceeding before the commission to determine the rates to be charged by a gas utility. Subsection (b) provides as follows:

In any proceeding commenced after April 1, 2002, to determine the rates to be charged by a gas utility, the gas utility shall file jurisdictionally allocated cost of service data on the basis of a test period, and the commission shall utilize a test period, consisting of actual data for the most recent 12 month period for which data are

available, fully adjusted separately to reflect estimated operations during the 12 months following the proposed effective date of the rates. After the initial filing, and until new rates go into effect, the utility shall file actual cost of service data as they become available for each month following the actual data which were filed. The utility shall have the burden of explaining and supporting the reasonableness of all estimates and adjustments contained in its cost of service data.

The Commission concludes as a matter of law that the Company has met its burden of proof to substantiate a revenue deficiency, which the Commission found as a matter of fact to equal \$26,557,218.

5.

The Commission concludes as a matter of law that the Company should be allowed to charge rates calculated to allow the Company an opportunity to recovery this deficiency and that such award will allow the Company the opportunity to earn a return on its assets which is not confiscatory, unjust or unreasonable.

6.

The Commission concludes as a matter of law that the provisions of this decision related to the allocation of the additional revenue requirement and the specific charges set by the Commission will provide the most equitable distribution of the additional revenue requirement mandated by the record.

7.

The Commission concludes as a matter of law that it has the authority under O.C.G.A. § 46-4-161 to refund funds from the USF to retail customers in such manner as the Commission shall deem equitable.

IV. ORDERING PARAGRAPHS

After consideration of all of the evidence presented in this proceeding in conjunction with consideration of the applicable law and regulatory policy within the existing legislative framework, and upon the Commission's findings of fact and conclusions of law, the Commission adopts and sets out the ordering paragraphs below.

A. WHEREFORE IT IS ORDERED, that Atlanta Gas Light Company is directed to increase rates to produce an increase in revenues in the amount of \$26,557,218, consistent with the provisions of this Order, with said rates to be effective for service rendered

on and after November 3, 2010.

B. ORDERED FURTHER, that the tariffs implemented by the Company to collect the aforesaid increased revenues of \$26,557,218 shall be submitted as a compliance filing within 30 days of the date of this Order subject to review by the Commission to ensure that such tariffs, as implemented, are proper and just. The rates shall be consistent with the findings of the Commission regarding Revenue Requirements in this Order utilizing the rate design methodology approved in this Order

C. ORDERED FURTHER, that the Company shall comply with all ruling and directives contained in the body of this Order.

D. ORDERED FURTHER, that the Commission shall pre-authorize a monthly disbursement of \$532,000 from the USF to the Company to be applied toward the actual cost of the program from November 2010 through December 2011.

E. ORDERED FURTHER, that due to the complexity of this matter and the short statutory deadline for the issuance of an order, the Commission issued a short order in this matter. The Commission now issues this more detailed order further explaining its decisions, findings and conclusions. To the extent that any provisions in the two orders are inconsistent, the provisions in this long order shall supersede any conflicting provisions in the short order.

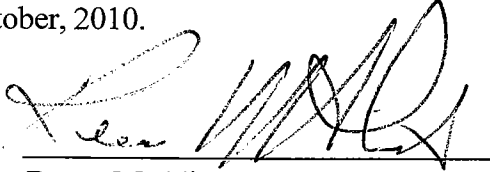
F. ORDERED FURTHER, that all findings, conclusions and statements made by the Commission and contained in the foregoing sections of this Order are hereby adopted as findings of fact, conclusions of law, and statements of regulatory policy of this Commission.

G. ORDERED FURTHER, that unless specified otherwise in this Order, the decisions adopted herein shall be effective immediately.

H. ORDERED FURTHER, that any motion for reconsideration, rehearing or oral argument or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

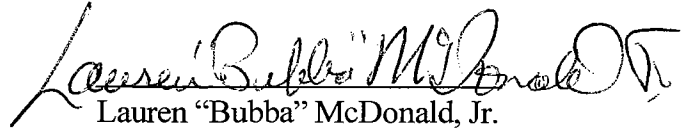
I. ORDERED FURTHER, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem just and proper.

The above by action of the Commission in Special Administrative Session on the 27th day of October, 2010.



Reece McAlister
Executive Secretary

12-21-10
Date



Lauren "Bubba" McDonald, Jr.
Chairman

Dec. 21, 2010
Date

**CERTIFICATE OF SERVICE
ATLANTA GAS LIGHT COMPANY
DOCKET NO. 31647**

**IN RE: PETITION OF ATLANTA GAS LIGHT COMPANY FOR APPROVAL OF
ADJUSTMENT OF ITS RATES AND REVISED TARIFF;**

I, the undersigned, do herewith certify that I have caused to be served the required copies of the enclosed Final Order Appearances. All parties are being provided an electronic copy.

Reece McAlister
Executive Secretary
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Respectfully submitted, this 6th day of
January, 2011

A handwritten signature in cursive script, appearing to read "Janice Sears", written over a horizontal line.

Janice Sears
Administrative Assistant

Decision 07-03-044 March 15, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-M) for Authorization, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007.

Application 05-12-002
(Filed December 2, 2005)

Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service, and Facilities of Pacific Gas and Electric Company (U 39-M).

Investigation 06-03-003
(Filed March 2, 2006)

(See Appendix A for a List of Appearances.)

**OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S
GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010**

TABLE OF CONTENTS

<u>Title</u>	<u>Page</u>
I. Summary	2
II. Procedural Background and Chronology	3
III. Summary of the Settlement Agreement	9
IV. Standard of Review	12
V. Review of the Settlement Agreement	13
A. Customer Services	13
1. Front Counters	15
a. Position of the Parties	15
b. Discussion	16
2. Mobile Home Park Billing Service	17
a. Summary of the Bill-Calculation Services	18
b. Discussion	20
3. Issues Raised by DRA	22
a. Customer Inquiry Assistance	22
b. Customer Care	23
c. Gas Field Services and Dispatch Operations	24
d. Emissions Reduction	25
e. Discussion	25
4. Issues Raised by Aglet, TURN, and Others	26
a. Billing, Revenue, and Records	26
b. Customer Service Standards	26
c. Critical Peak Pricing	27
i. Position of the Parties	27
ii. Discussion	28
d. Direct Access Service Fees	28
i. Position of the Parties	28
ii. Discussion	29
e. Read and Investigate Meters	30
i. Position of the Parties	30
ii. Discussion	30
f. Uncollectibles Factor	31

i.	Position of the Parties	31
ii.	Discussion	32
g.	Late-Payment Fee Implementation Expense	33
i.	Position of the Parties	33
ii.	Discussion	34
h.	Service-Restoration Fee.....	34
i.	Position of the Parties	34
ii.	Discussion	35
i.	Non-Sufficient Funds Fee	35
i.	Position of the Parties	35
ii.	Discussion	37
j.	Customer Retention & Economic Development	38
i.	Position of the Parties	38
(A)	The Settlement Agreement	38
(B)	Aglet.....	40
(C)	TURN	41
(D)	PG&E and the Other Settling Parties	41
ii.	Discussion	43
5.	Conclusion re: Customer Services	46
B.	Electric Distribution.....	46
1.	Electric Distribution Revenues	46
2.	Electric Distribution O&M Expenses.....	46
a.	Issues Raised by DRA	47
i.	Issues Other than Vegetation Management.....	48
(A)	Distribution Line Equipment Inspect and Test	48
(B)	Preventative Maintenance	48
(1)	Overhead Repairs.....	48
(2)	BG Projects	48
(3)	Other.....	49
(C)	Pole Asset Management.....	49
(D)	Externally Driven Work.....	50
(E)	Conclusion	50
ii.	Vegetation Management.....	51
(A)	Routine Tree Trimming & Removal.....	51
(B)	Increased Staffing.....	52

(C) Recovery of CDF-Mandated Costs	52
(D) The Settlement Agreement	53
(E) Discussion	53
iii. Other Electric Distribution O&M Expenses	53
b. Issues Raised by TURN.....	54
i. Double Recovery of AMI-Related Costs.....	54
(A) Position of the Parties	54
(B) Discussion	56
ii. TURN's Alternate Proposal for TOU Meter Expenses	56
(A) Position of the Parties	56
(B) Discussion	57
iii. Cessation of TOU Meter Installations	58
(A) Position of the Parties	58
(B) Discussion	58
iv. Forecasted Meter Expenses for 2007	59
(A) Position of the Parties	59
(B) Discussion	60
v. Revised Accounting for Meters.....	61
(A) Position of the Parties	61
(B) Discussion	62
c. Conclusion	62
3. Electric Distribution Capital Expenditures.....	62
a. Summary of the Record	63
i. Pole Asset Management.....	63
ii. Undergrounding Projects.....	63
iii. Tie-Cable Circuits.....	63
iv. Plastic Insulated Cables.....	64
v. Lead Cables	65
vi. Other Electric Distribution Capital Expenditures	66
b. Discussion	66
4. Electric Distribution Plant.....	67
C. Gas Distribution	67
1. Gas Distribution Revenues	67
2. Gas Distribution O&M Expenses	67
a. Issues Raised by DRA	68

b. Issues Raised by TURN.....	69
i. Mark and Locate.....	69
(A) Position of the Parties	69
(B) Discussion	71
ii. Leak Survey.....	74
(A) Position of the Parties	74
(B) Discussion	75
iii. Operate Gas Systems	76
(A) Position of the Parties	76
(B) Discussion	76
iv. Corrective Maintenance	77
(A) Position of the Parties	77
(B) Discussion	78
v. Meter Protection Program	79
(A) Position of the Parties	79
(B) Discussion	80
c. Conclusion	80
3. Gas Distribution Capital Expenditures	80
a. Summary of the Record	81
i. Gas Pipeline Replacement Program.....	81
ii. Gas Reliability.....	82
b. Discussion	82
4. Gas Distribution Plant	83
D. Electric Generation.....	84
1. Generation Revenues	84
2. Generation O&M Expenses.....	84
a. Hydro Operations.....	84
i. Issues Raised by DRA.....	85
ii. Issues Raised by Aglet and TURN	86
(A) Forecasted Hydro O&M Expenses for 2007	86
(1) Position of the Parties	86
(2) Discussion.....	87
(B) Delayed Projects.....	88
(1) Position of the Parties	88
(2) Discussion.....	89

(C) Regulatory Fees	90
(1) Position of the Parties	90
(2) Discussion.....	92
(D) Deferred Maintenance	92
(1) Position of the Parties	92
(2) Discussion.....	94
b. Nuclear Operations.....	95
i. Issues Raised by the Parties	96
(A) New Information System and Pump	96
(1) Position of the Parties	96
(2) Discussion.....	96
(B) License Renewal Feasibility Study	96
(1) Position of the Parties	97
(2) Discussion.....	100
(C) Additional Staffing	105
(D) NEI Membership Dues.....	106
ii. Fossil Operations.....	107
(A) Issues Raised by TURN.....	107
(1) Position of the Parties	107
(2) Discussion.....	109
iii. Electric Supply Administration	110
(A) Issues Raised by TURN.....	111
(1) Position of the Parties	111
(2) Discussion.....	113
c. Conclusion	117
3. Generation Capital Expenditures.....	117
a. Hydro Capital Expenditures	118
i. Issues Raised by Aglet and TURN	119
(A) Position of the Parties	119
ii. Discussion	120
b. Nuclear Capital Expenditures.....	122
i. Issues Raised by the Parties	122
(A) Nuclear Core Plant Work.....	122
(1) Position of the Parties	122
(2) Discussion.....	123

(B) Radioactive Waste Storage Facility	125
(1) Position of the Parties	125
(2) Discussion.....	127
(C) Reactor Vessel Head Replacement Project	127
(1) Position of the Parties	127
(2) Discussion.....	128
ii. Conclusion re: Nuclear Capital Expenditures	129
c. Fossil Capital Expenditures.....	130
i. Position of the Parties	130
ii. Discussion	131
d. Generation Plant	132
e. Nuclear Fuel Inventory	132
E. Common and Miscellaneous Revenues, Expenses, and Capital	133
1. Other Operating Revenues	133
a. Issues Raised by TURN.....	134
i. Reconnection Fees	134
(A) Position of the Parties	134
(B) Discussion	134
ii. Timber Sales	135
(A) Position of the Parties	135
(B) Discussion	135
iii. Work Requested by Others.....	136
(A) Position of the Parties	136
(B) Discussion	138
2. Administrative and General Expenses.....	140
a. General Matters and Corporate Services.....	141
i. Issues Addressed by DRA	141
(A) Normalized Adjustments.....	141
(B) Time Tracking.....	141
(C) Corporate Services	141
(D) Discussion	143
ii. Issues Raised by TURN.....	144
(A) Capitalization of A&G Costs.....	144
(1) Position of the Parties	144
(2) Discussion.....	145

(B)	Law Department Costs for Outside Counsel.....	146
(1)	Position of the Parties	146
(2)	Discussion.....	147
(C)	Public Policy and Government Affairs	148
(1)	Position of the Parties	148
(2)	Discussion.....	150
(D)	Membership Dues and Political Contributions	151
(1)	Position of the Parties	151
(2)	Discussion.....	153
b.	Holding Company Costs	154
i.	Issued Raised by DRA	154
ii.	Issues Raised by TURN	156
c.	Employee Compensation.....	156
i.	Total Compensation.....	156
(A)	Employee Incentive Plan	157
(B)	Discussion	158
ii.	Pensions and Benefits	159
(A)	Pension Contributions.....	159
(B)	Issues Raised by DRA.....	161
(1)	Medical Escalation Rates.....	161
(2)	Service Award Program	162
(3)	Relocation Benefits	162
(4)	PBOP Medical and Disability Benefits	162
(5)	The Settlement Agreement	163
(6)	Discussion.....	163
(C)	Aglet's Comparison of Utility Medical Costs	164
(1)	Position of the Parties	164
(2)	Discussion.....	165
(D)	TURN's Linkage of P&B Costs to Payroll	166
(1)	Position of the Parties	166
(2)	Discussion.....	166
d.	Other A&G Expenses	167
e.	Unbundling.....	168
f.	Conclusion re: A&G Expenses	169
3.	General Services and Other Support Costs	169

a.	Areas of Agreement.....	169
b.	Issues Raised by the Parties.....	170
i.	Transportation Services Capital Expenditures	170
(A)	Equipment Replacement.....	171
(B)	EPA Compliance	171
(C)	Capital Tools	172
(D)	Issues Raised By TURN.....	172
(E)	The Settlement Agreement	173
(F)	Discussion	173
ii.	Company Airplane	173
(A)	Position of the Parties	173
(1)	The Settlement Agreement	173
(2)	Aglet	176
(3)	TURN	176
(B)	Discussion	178
iii.	Corporate Real Estate	183
iv.	Environmental Programs.....	185
v.	Information Technology.....	187
4.	Common Plant Capital Expenditures.....	189
5.	Customer Advances for Construction.....	190
a.	Position of the Parties.....	190
b.	Discussion	190
6.	Transfer of CAC to CIAC	191
a.	Position of the Parties.....	191
b.	Discussion	192
7.	Working Cash	193
a.	The Settlement Agreement	194
b.	Customer Deposits	195
i.	Position of the Parties	195
(A)	Aglet.....	195
(B)	TURN	196
(C)	PG&E and the Other Settling Parties	198
ii.	Discussion	201
c.	Lead-Lag Calculation of Working Cash	202
i.	Revenue Lag.....	202

(A) Position of the Parties	202
(B) Discussion	203
ii. Savings Fund Lag.....	204
(A) Position of the Parties	204
(B) Discussion	205
8. Depreciation Expense	207
a. Issues Raised by DRA	208
i. The Settlement Agreement	208
ii. Discussion	210
b. Depreciation Issues Raised by TURN.....	212
i. Regulatory Liability for Removal Costs	212
(A) Position of the Parties	213
(1) TURN	213
(2) Aglet	214
(3) SCE	215
(4) PG&E and the Other Settling Parties	215
(B) Discussion	215
ii. TURN's Normalized Net Salvage Proposal	218
(A) Position of the Parties	219
(1) TURN	219
(2) PG&E and the Other Settling Parties	221
(3) SDG&E and SCG	223
(4) SCE	224
(B) Discussion	226
iii. Net Present Value Depreciation Study	229
(A) Position of the Parties	229
(1) TURN	229
(2) PG&E and the Other Settling Parties	230
(3) SCE	231
(B) Discussion	232
9. Taxes.....	233
a. Summary	233
b. Discussion	234
c. Tax Deduction for ESOP Dividends	234
i. Position of the Parties	235

(A) TURN	235
(B) PG&E and the Other Settling Parties	236
ii. Discussion	237
F. Revenue Requirement and Rate Base	238
1. Results of Operations for 2007	238
2. Revenue Requirement for Attrition Years	240
a. Position of the Parties	240
i. The Settlement Agreement	240
ii. Aglet	244
iii. PG&E and the Other Parties	245
b. Discussion	245
3. Interference with Other Proceedings	248
a. Position of the Parties	248
b. Discussion	248
4. PG&E Financial Health	249
a. Position of the Parties	249
b. Discussion	250
5. Vacancies	251
a. Position of the Parties	251
b. Discussion	251
G. General Report Items and Other Miscellaneous Matters	253
1. Escalation Rates	253
2. Productivity	253
3. Mission Substation	254
4. MOU re: Operations Affecting Disabled Persons	255
a. Discussion	256
5. Performance Incentive Mechanism	257
VI. Approval of the Settlement	257
A. Reasonable in Light of the Whole Record	257
B. Consistent with the Law	263
C. The Public Interest	263
D. Additional Issues Raised by Aglet and TURN	264
1. Flawed Settlement Process	264
2. Overall Outcome Is Unreasonable	265
3. No Justification of Outcomes for Individual Issues	267

4. Affected Interests Oppose the Settlement.....	268
E. Conclusion	268
VII. Issued Raised by the Greenlining Institute.....	268
A. Executive Compensation	269
B. Supplier Diversity, Personnel Diversity, and Philanthropy.....	269
1. Greenlining-PG&E Accord re: Supplier Diversity	270
2. Greenlining-PG&E Accord re: Board and Management Diversity	270
3. Greenlining-PG&E Accord re: Philanthropy.....	270
VIII. Implementation of Today’s Opinion	271
IX. Assignment, Categorization, and Need for Hearing	271
X. Comments on the Alternate Proposed Decision.....	271
Findings of Fact.....	272
Conclusions of Law	277
ORDER	282

Appendix A: List of Appearances

Appendix B: PG&E-DIRA Memorandum of Understanding

Appendix C: General Rate Case settlement Agreement

OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

I. Summary

This Opinion adopts a Settlement Agreement that resolves most issues arising from Pacific Gas and Electric Company's (PG&E) general rate case Application (A.) 05-12-002. The adopted Settlement Agreement increases PG&E's revenue requirement for Gas Distribution, Electric Distribution, and Generation by \$213 million in 2007 and by \$125 million annually during 2008, 2009, and 2010. PG&E is also allowed to recover an additional \$35 million for a refueling outage at the Diablo Canyon nuclear power plant. Compared to the preceding year, this Opinion authorizes an increase in PG&E's general rate case (GRC) revenue requirement of 4.5% in 2007, 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The increase in PG&E's overall revenue requirement is 1.4% in 2007, 0.8% in 2008, 1.0% in 2009, and 0.6% in 2010.

The other elements of the adopted Settlement Agreement include the following:

- The addition of a third attrition year, 2010, which shifts PG&E's next GRC to test-year 2011.
- A provision that keeps all 84 of PG&E's front counters open pending further developments in Phase 2 of this proceeding regarding PG&E's proposal to close its front counters.
- A Bill-Calculation Service for mobile home park owners with sub-metered tenants.
- A memorandum of understanding between PG&E and the Disability Rights Advocates (DIRA) wherein PG&E agrees to take certain measures to improve its operations affecting disabled persons.

The increased revenue requirement authorized by this Opinion is effective on January 1, 2007, pursuant to Decision (D.) 06-10-033. This revenue requirement is in addition to increases previously authorized in this proceeding for pensions costs in the amounts of \$98 million for 2007, \$102 million for 2008, \$106 million for 2009, and \$111 million for 2010.¹

There are additional elements of today's Opinion that consist of accounting and reporting requirements. These include a requirement for PG&E to record a regulatory liability for \$2.1 billion that PG&E has collected in rates but not yet spent to retire and remove assets from service.

The Settlement Agreement does not address issues raised by the Greenlining Institute (Greenlining). These issues focused on executive pay, supplier diversity, employee diversity, and corporate philanthropy. The issues raised by Greenlining are addressed separately. Greenlining and PG&E were able to resolve these issues, and their accord is adopted by today's Opinion.

This proceeding remains open to consider issues associated with PG&E's request to close many of its customer-service counters.

II. Procedural Background and Chronology

PG&E filed A.05-12-002 on December 2, 2005. In A.05-12-002, PG&E requested, among other things, authority to increase its GRC revenue requirement to \$5.238 billion effective January 1, 2007, for Gas Distribution, Electric Distribution, and Electric Generation. Compared to 2006, the requested

¹ These are estimated pension costs. The actual revenue requirement for pension costs will vary depending on several factors. See D.06-06-014 for an explanation of the variance.

GRC revenue requirement for 2007 represented an increase of \$524 million, or 11.1%. PG&E requested additional increases in 2008 and 2009.

A prehearing conference (PHC) was held on January 23, 2006. Assigned Commissioner Bohn issued a Ruling and Scoping Memo (ACR) on February 3, 2006, that established the scope and schedule for the proceeding. The ACR called for hearings to begin in May 2006 and a final decision in December 2006 on all issues except PG&E's proposed Performance Incentive Mechanism.

On March 2, 2006, the Commission issued Order Instituting Investigation (I.) 06-03-003, the companion investigation to this GRC. The purpose of I.06-03-003, which was consolidated with A.05-12-002, was to allow the Commission to (1) address matters raised by parties other than PG&E, and (2) issue orders on matters for which PG&E might not be the proponent.

In a related proceeding, A.05-12-021, PG&E requested recovery of contributions made to its employee pension plan in 2006. Granting A.05-12-021 would reduce PG&E's revenue requirement for pension costs in this GRC proceeding. On March 8, 2006, PG&E, the Commission's Division of Ratepayer Advocates (DRA), and the Coalition of California Utility Employees (CCUE) filed a settlement agreement that resolved all issues in A.05-12-021 and all pension-cost issues in this GRC proceeding. Among other things, the settlement allowed PG&E to recover the following GRC revenue requirement for pension costs: \$155 million in 2006, \$98.2 million in 2007, \$101.7 million in 2008, and \$106.1 million in 2009. The Commission adopted the uncontested settlement agreement in D.06-06-014.

DRA served its written testimony on GRC issues on April 14, 2006. The following parties served their written testimony on April 28, 2006: the Modesto Irrigation District (Modesto ID), the Merced Irrigation District (Merced ID), the

South San Joaquin Irrigation District (SSJID), DIRA, Aglet Consumer Alliance (Aglet), The Utility Reform Network (TURN), Greenlining, and others. The following parties served rebuttal testimony on May 17, 2006: PG&E, Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and Southern California Gas Company (SCG).

Ten public participation hearings (PPHs) were held at various locations in PG&E's service territory during April and May, 2006.² Hundreds of letters were also received from the public.

On May 30, 2006, the assigned Administrative Law Judge (ALJ) granted the joint motion of PG&E, DRA, and several intervenors to defer to early 2007 PG&E's proposal to close all of its front counters where customers can obtain help, information, and services. A noticed settlement conference regarding PG&E' proposal was held on February 15, 2007.

On May 31, 2006, the ALJ ruled that all issues associated with PG&E's proposed late-payment fee would be removed from this proceeding and considered, as appropriate, in I.03-01-012.³

A second PHC was held on May 25, 2006. Twenty-five days of evidentiary hearings were held between May 31 and July 7, 2007. During the evidentiary hearings, the ALJ admitted into the record the written testimony of 118 witnesses and approximately 157 other hearing room exhibits.

² The PPHs were held at the following locations: Oakland, Ukiah, Santa Rosa, King City, Salinas, San Louis Obispo, Modesto, Fresno, Woodland, and Chico.

³ I.03-01-012 is the companion investigation to PG&E's previous GRC proceeding, A.02-11-017.

After the conclusion of hearings, PG&E's requested revenue requirement for 2007 stood at \$5.109 billion. The decrease from the initial amount in the A.05-12-002 was due to (1) PG&E's concessions on several issues raised by DRA, Aglet, and TURN, and (2) the resolution of pension-cost issues by D.06-06-014. PG&E's revised request for 2007 represented an increase of \$395 million, or 8.38%, over its 2006 authorized revenue requirement. By comparison, DRA recommended \$4.734 billion for 2007, or \$375 million less than PG&E's request.

On August 16, 2006, PG&E and several parties held a noticed settlement conference to discuss a proposed settlement. On August 21, 2006, PG&E and most of the active parties jointly filed a settlement agreement⁴ and a motion to adopt the settlement agreement.⁵ The Settlement Agreement purports to resolve all issues except those raised by Greenlining. The parties joining in the Settlement Agreement are PG&E, DRA, Modesto ID, Merced ID, SSJID, DIRA, the Western Manufactured Housing Communities Association (WMA),

⁴ Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees. This document is referred to hereafter as "the Settlement Agreement" or "the Settlement."

⁵ Motion of Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees For Approval of Settlement Agreement. This document is referred to hereafter as the "Settlement Motion." The Settlement Agreement was attached to the Settlement Motion.

California Farm Bureau Federation (CFBF), SCE, SDG&E, SCG, and CCUE (together, the Settling Parties). Most of the Settling Parties join only in certain paragraphs of the Settlement Agreement that resolve the particular issues raised by these Parties.⁶ A copy of the Settlement Agreement is in Appendix C of today's Opinion.

Noticed technical conferences regarding the Settlement Agreement were held on August 23 and September 6, 2006. PG&E also responded to several written data requests regarding the Settlement Agreement.

The Settlement Agreement is opposed by Aglet, the Alliance for Nuclear Responsibility and the Sierra Club (ANR/SC), and TURN. Rule 12.2 of the Commission's Rules of Practice and Procedure (Rule 12.2) governs comments filed by parties who contest a settlement agreement. Rule 12.2 states:

Comments must specify the portions of the settlement that the party opposes, the legal basis of its opposition, and the factual issues that it contests. If the contesting party asserts that hearing is required by law, the party shall provide appropriate citation and specify the material contested facts that would require a hearing. Any failure by a party to file comments constitutes waiver by that party of all objections to the settlement, including the right to hearing.

Comments opposing the Settlement were filed on September 20, 2006, by Aglet, ANR/SC, and TURN. None of these parties requested an evidentiary

⁶ Settlement Motion, p. 2, Fn. 1. Modesto ID joins only in paragraphs 1, 2, 3, 10, 11, 19, 49, and 50 of the Settlement. Merced ID joins only in paragraphs 1, 2, 3, 10, 11, 19, and 50. SSJID joins only in paragraphs 1, 2, 3, 10, and 19. DIRA joins only in paragraphs 1, 2, 3, 13A, and 48. WMA joins only in paragraphs 1, 2, 3, 12, and 25. CFBF joins only in paragraphs 1, 2, 3, 13B, and 24. SCE, SDG&E, and SoCalGas join only in paragraphs 1, 2, 3, 13C, and 41. (See Settlement, para. 3, conditions M-S.)

hearing on the Settlement.⁷ Three sets of reply comments were filed on October 5, 2006, by (1) SCE, (2) jointly by SDG&E and SCG, and (3) jointly by the Settling Parties other than SCE, SDG&E, and SCG.

As noted earlier, the Settlement Agreement does not resolve issues raised by Greenlining. These issues – which include executive compensation, supplier diversity, employee diversity, and corporate philanthropy – were the subject of separate briefs. PG&E was the only party to respond to the issues raised by Greenlining. Greenlining filed an opening brief on August 7, 2006. PG&E filed a reply brief on August 21, 2006. Greenlining filed a closing brief on August 28, 2008. PG&E and Greenlining resolved these issues at the last minute in their comments on the Alternate Proposed Decision.

The ACR issued on February 3, 2006, set a schedule that provided for the issuance of a final decision regarding most GRC issues in December 2006. This schedule was extended in several ALJ rulings in order to provide time for the parties to reach a settlement. On August 11, 2006, PG&E filed a motion for the Commission to issue an interim decision that makes PG&E's GRC revenue requirement for the 2007 test year adopted in this proceeding effective on January 1, 2007, in the event the Commission issues a final decision adopting PG&E's GRC revenue requirement after that date. The Commission granted PG&E's unopposed motion in D.06-10-033. As a result, the 2007 GRC revenue requirement authorized by today's Opinion is effective as of January 1, 2007.

⁷ Greenlining's informal request for an evidentiary hearing was denied by the assigned ALJ in a ruling issued on October 6, 2006.

Greenlining and Aglet submitted timely requests pursuant to Rule 13.13(b) for an oral argument before a quorum of the Commission. The oral argument was held on March 2, 2007.

In the remainder of today's Opinion, we will first evaluate the Settlement Agreement and the opposition to the Settlement. We will then address the issues raised by Greenlining.

III. Summary of the Settlement Agreement

The Settlement Agreement purports to resolve all issues in this proceeding except those issues raised by Greenlining. The resolved issues include those raised by Aglet, ANR/SC, and TURN, who are not parties to the Settlement.

The Settlement Agreement adopts a GRC revenue requirement of \$4.927 billion in 2007.⁸ The following table compares the Settlement revenue requirement with the litigation positions of PG&E and DRA:

⁸ The revenue requirement adopted by the Settlement Agreement excludes costs that are (i) regulated by the Federal Energy Regulatory Commission (FERC), and (ii) the subject of other Commission proceedings, including replacement of PG&E's Diablo Canyon steam generators, the Contra Costa 8 generating facility, and Advanced Metering Infrastructure. The Settling Parties agree that under the Settlement there is no double recovery of costs in this GRC and other proceedings.

2007 GRC Revenue Requirement (\$ millions)							
		Comparison Exhibit		Settlement			
	2006 Authorized	PG&E	DRA	Settlement	Settltmt. vs. 2006	Settltmt. vs. PG&E	Settltmt. vs. DRA
Electric Distrib.	2,648	2,991	2,809	2,870	222	(121)	61
Gas Distrib.	1,027	1,062	1,001	1,047	21	(15)	46
Generation	1,039	1,056	924	1,010	(30)	(46)	86
Total	4,714	5,109	4,734	4,927	213	(182)	193
Source: Settlement, Appendix B.							

The GRC revenue requirement adopted by the Settlement for 2007 represents an increase of \$213 million, or 4.5%, compared to 2006. On a total system basis, the Settlement increases PG&E's billed revenues by 1.4% in 2007.

The Settlement Agreement adds a third attrition year – 2010 – to the GRC cycle. The Settlement provides for annual attrition increases of \$125 million in 2008, 2009, and 2010, and an additional \$35 million in 2009 for a refueling outage at Diablo Canyon. The following table compares the Settlement outcome for attrition to PG&E's and DRA's litigation positions:

2008 – 2010 Attrition GRC Revenue Requirement (\$ millions)					
	PG&E	DRA	Settlement	Settlement vs. PG&E	Settlement vs. DRA
2008	143	100	125	(18)	25
2009	180	131	125	(55)	4
2010	--	--	125	--	--
2009 Diablo Canyon Refueling			35	--	--
Source: Settlement, Appendix E.					

Compared to the immediately preceding year, the Settlement increases PG&E's GRC revenues by 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The compound percentage increase over 2007 - 2010 is 12.46%. The above tables show that the Settlement provides PG&E with approximately \$634 million less than it requested in cumulative revenues for 2007, 2008, and 2009.⁹

As noted previously, the Settlement divides the GRC revenue requirement among Gas Distribution, Electric Distribution, and Electric Generation. The Settlement further divides the revenue requirement into numerous areas. Some of the specific dollar amounts for 2007 are as follows:

- Operations and maintenance (O&M) expense - \$1.079 billion.
- Depreciation expense - \$942 million.
- Total Company administrative and general (A&G) expense - \$772 million.
- Customer services expense - \$431 million.
- Net weighted capital additions - \$453 million.
- Rate Base - \$12.6 billion.
- Fossil decommissioning refund - \$26.8 million.
- Other operating revenues - \$116 million.

The Settlement resolves numerous issues that are not expressed in dollar terms. These issues include:

- Forecasts of customers, sales, and revenues at present rates.
- Continuation of the one-way Vegetation Management Balancing Account, and a new Vegetation Management tracking account.
- Uncollectibles factor.
- Various customer fees.

⁹ \$634 million = (3 x 182 million) + (2 x 18 million) + \$55 million.

- Continued operation of all front counters pending further litigation and possible settlement of PG&E's proposal to close its front counters.
- Billing services for mobile home parks.
- Direct access fees.
- Replacement of the Company airplane.
- Capitalization rates.
- A&G allocations to non-GRC operations.
- Franchise fee factor.
- Memorandum of Understanding between DIRA and PG&E.
- O&M labor factors.
- Results of operations model.
- Withdrawal of PG&E's proposed Earnings-Sharing Mechanism.
- Withdrawal of PG&E's proposed Performance-Incentive Mechanism.

The Settling Parties request that the Commission approve the Settlement Agreement without modification and find that the Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

IV. Standard of Review

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.¹⁰ Although the Commission favors the settlement of disputes, Rule 12.2 provides that the Commission will not approve a settlement unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

¹⁰ D.05-03-022, *mimeo.*, pp. 7-8.

The Settlement Agreement is opposed by Aglet, ANR/SC, and TURN. The Commission's policy is that contested settlements should be subject to more scrutiny compared to an all-party settlement.¹¹ As explained in D.02-01-041:

In judging the reasonableness of a proposed settlement, we have sometimes inclined to find reasonable a settlement that has the unanimous support of all active parties in the proceeding. In contrast, a contested settlement is not entitled to any greater weight or deference merely by virtue of its label as a settlement; it is merely the joint position of the sponsoring parties, and its reasonableness must be thoroughly demonstrated by the record.
(D.02-01-041, *mimeo.*, p. 13.)

For the preceding reasons, we will review the Settlement's resolution of every contested issue, with careful consideration given to each issue raised by Aglet, ANR/SC, and TURN. The purpose of our issue-by-issue review is not to second guess the Settlement outcome for every individual issue, but to assess whether the Settlement as a whole is reasonable in light of the entire record, consistent with applicable law, and in the public interest.

V. Review of the Settlement Agreement

A. Customer Services

PG&E's Customer Services organization consists of the processes, technology, and people that together link PG&E with its 5 million electric customers and 4.1 million gas customers. PG&E requested \$437.7 million for Customer Services expenses in 2007. PG&E also requested increases in several

¹¹ D.96-01-011, Finding of Fact (FOF) 5. See D.96-01-011, 1996 Cal. PUC LEXIS 23, 39, 40 ("This more detailed review and heightened scrutiny is especially appropriate when the settlement is not all-party.").

fees and its uncollectibles factor. DRA, Aglet, TURN, and others opposed certain aspects of PG&E's request.

The Settlement adopts \$431 million for Customer Services expenses in 2007, which is \$7 million less than PG&E requested. The following table compares the Settlement outcome with PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Customer Services Expenses (\$ millions)							
		Comparison Exhibit		Settlement			
	2006 Authorized	PG&E	DRA	Settlement	Settltmt. vs. 2006	Settltmt. vs. PG&E	Settltmt. vs. DRA
Electric Distrib.	186.6	187.0	180.3	184.3	(2.3)	(3.7)	4.3
Gas Distrib.	237.6	250.7	245.1	246.8	9.2	(3.9)	1.7
Total	424.2	437.7	425.4	431.1	6.9	(6.6)	5.7
Source: Settlement Agreement, Appendix B, Lines 2, 12, and 28.							

The Settling Parties agree that capital expenditures for Customer Services is subsumed within the capital expenditures adopted by the Settlement for Electric Distribution, Gas Distribution, and Common Plant, which are addressed elsewhere in today's Opinion. The Settling Parties also reached the following agreements on other Customer Services issues:

- PG&E will keep its front counters open pending a resolution of this issue either through settlement or Commission decision. (Settlement, para. 24.)
- PG&E will implement billing services for mobile home park owners with sub-metered tenants. (Settlement, para. 25.)
- Direct access service fees will remain at their current level (Settlement, para. 26.)
- The uncollectibles factor will be 0.002586. (Settlement, para. 20.)

- The “restoration for non-payment” fee will be increased from \$20.00 during regular business hours and \$30.00 during non-business hours to \$25.00 and \$37.50, respectively. CARE customers are exempted from the increase. (Settlement, para. 22.)
- The non-sufficient funds (NSF) fee will be increased from \$8.00 to \$11.50. (Settlement, para. 21.)
- PG&E will implement a new service quality standard that pays \$100 to customers whose service is improperly shut off. (Settlement, para. 23.)

Below, we assess the reasonableness of the Settlement outcome for Customer Services in light of the record on the issues raised by DRA and others.

1. Front Counters

a. Position of the Parties

PG&E operates 84 “front counters” where customers can establish service, pay bills, and obtain a variety of utility services and information. About 40% of the front counters are located in PG&E service centers, which are used primarily for field service operations. The remainder of the front counters are located in office space either owned by PG&E or leased from others.

In A.05-12-002, PG&E proposed to close all 84 front counters by June 30, 2007, and to transfer many of the functions to pay stations operated by third parties. Closing the front counters would reduce PG&E’s revenue requirement by \$24 million annually starting in 2008. If the Commission does not approve PG&E’s proposal, PG&E requested \$37.1 million in expenses for front counters in 2007 and \$0.15 million for capital expenditures in 2007.

Several parties opposed PG&E’s proposal to close its front counters (i.e., DRA, TURN, and CFBF). The only party to contest PG&E’s expense request for continued operations was TURN, who argued for a 20% reduction of PG&E’s requested expenses. No party contested the requested capital expenditures.

On May 26, 2006, the active parties for front counter issues submitted a joint motion seeking to defer to Phase 2 of this proceeding all issues regarding PG&E's proposal to close its front counters. The unopposed motion was granted by an ALJ ruling issued on May 30, 2006.

The Settlement Agreement provides that (1) PG&E will keep its front counters open pending the resolution of this matter in Phase 2 of this GRC proceeding either through settlement or a Commission decision, and (2) PG&E should be granted \$37.1 million annually to operate all of its front counters. If any front counters are closed, PG&E will adjust its rates downward to reflect the savings from such closures.¹²

On February 7, 2007, PG&E filed a notice of a settlement conference on February 15, 2007, to discuss the potential resolution of all front-counter issues.

b. Discussion

The evidentiary record shows that PG&E's front counters are heavily used. Approximately 10% of all customer transactions occur at the front counters. During 2005, there were 4,560,387 payment transactions at the front counters and 1,080,918 non-payment transactions.¹³

The importance of the front counters to PG&E's customers was highlighted at the Public Participation Hearings (PPHs). Many of the speakers at the PPHs said that PG&E's front counters are often the only way to resolve customer service issues. For example, several speakers emphasized that PG&E's front counters provide vital services to farm communities. These speakers explained that many farm workers do not have checking accounts and rely on front

¹² Settlement Agreement, para. 24.

¹³ Exhibit DRA-9, p. 9-16.

counters to pay their bills in cash and to resolve billing problems. They also described how farmers' difficulties with PG&E can be much more complicated than those of typical residential customers because farmers generally use far more gas and electricity than most residential users, often have multiple meters and utility bills, and the agricultural tariff schedules can be difficult to understand. These speakers described how PG&E's representatives at front counters understand the special needs of farmers and can resolve problems quickly, while the PG&E's representatives in a distant call center are generally unfamiliar with the intricacies of arcane agricultural tariffs.¹⁴

In light of the clear public need for the services provided by PG&E's front counters, we concur with the Settlement outcome that keeps all front counters open and provides associated funding. To ensure this intent is fulfilled, we will order PG&E to not make any significant reductions to the staffing or operations of its existing front counters without Commission authorization¹⁵ pending the Commission's consideration in Phase 2 of an apparent settlement that has been reached on front-counter issues.¹⁶

2. Mobile Home Park Billing Service

There are approximately 1,627 mobile home parks (MHPs) in PG&E's service territory with master meters for gas and electric service. These MHPs

¹⁴ See, generally, Reporter's Transcript (RT) of the PPHs held in Woodland and Chico on May 17 and 18, 2006, respectively.

¹⁵ PG&E may, of course, make necessary changes to the operations and locations of its front counters in response to circumstances, such as moving the location of a front counter due to the expiration of a lease.

¹⁶ As noted previously, on February 7, 2007, PG&E filed a notice of a settlement conference on February 15, 2007, to discuss the potential resolution of all front-counter issues.

have around 89,000 sub-metered tenants. MHP owners are required by Pub. Util. Code § 739.5¹⁷ to (1) charge their sub-metered tenants the same rates that PG&E charges its directly metered customers, and (2) provide itemized bills to their tenants that have the same general form and content as the utility's bill.

In D.04-11-033, the Commission ordered PG&E to analyze the potential for providing bill-calculation services to MHP owners with sub-metered tenants.¹⁸ On June 27, 2006, PG&E, WMA, and TURN submitted a joint proposal for PG&E to calculate the gas and electric utility bills for sub-metered tenants of MHPs ("Joint Proposal").¹⁹ There is no opposition to the Joint Proposal.

The Joint Proposal is incorporated into the Settlement Agreement. The Settling Parties agree that the Joint Proposal is a reasonable compromise of the parties' positions and complies with § 739.5 and D.04-11-033.²⁰

a. Summary of the Bill-Calculation Services

PG&E, TURN, and WMA (collectively, "the Joint Parties") propose that PG&E offer to MHP owners a Bill-Calculation Service like that described in D.04-11-033. MHP owners will have to sign an agreement to use the Services for a minimum of 12 months. Once enrolled, MHP owners will enter information at www.pge.com that PG&E needs to calculate utility bills for each tenant. MHP owners will be responsible for (1) the collection of timely and accurate meter reads, and (2) the submittal of timely meter-read data to PG&E at www.pge.com.

¹⁷ All section references are to the Public Utilities Code unless otherwise noted.

¹⁸ D.04-11-033, Ordering Paragraph (OP) 12.

¹⁹ The Joint Proposal, which is contained in Exhibit PG&E-70, is modeled on SCE's MHP bill-calculation services approved by the Commission in D.06-05-016.

²⁰ Settlement Agreement, para. 25.

Using information provided by MHP owners, PG&E will calculate sub-metered tenants' bills in accordance with the applicable residential rate schedules and send the bill calculations to the MHP owners via email. PG&E's bill calculations will usually be performed within two business days.

PG&E will handle billing inquiries from MHP tenants by providing tenants with information on the bill calculation and applicable rate schedule. For all other disputes (*e.g.*, usage amounts, meter accuracy, etc.), PG&E will refer the tenant to the MHP owner for resolution and inform the tenant that a complaint may be submitted to the Commission's Consumer Affairs Branch.

The Joint Proposal gives PG&E until June 1, 2007, to begin offering the MHP Bill-Calculation Services in order to provide PG&E with sufficient time to design, develop, test, and implement the Services.

D.04-11-033 requires PG&E's costs for MHP Bill-Calculation Services to be recovered from MHP owners. PG&E intends to recover its costs via the monthly service fee and a special services fee shown in the following table:

Proposed MHP Bill Calculation Service Fees	
Description	Amount
One-Time Initial Setup Charge	Free
Monthly Customer Charge Includes: * Development Expense * Bill Calculation Transaction Fee * Bill Presentation	\$0.27 per tenant per month
Special Service Fee	Actual labor & materials

PG&E estimates that the one-time costs to develop the Bill-Calculation Services will be \$500,000, and that ongoing costs will be \$100,000 annually. The estimated costs exclude expenses already recovered in base rates. Assuming

development costs are spread over five years, PG&E would need to recover \$200,000 per year from MHP owners (for the first five years). The Joint Parties estimate the monthly fee of \$0.27 per tenant will recover all costs for MHP Bill-Calculation Services directly from MHP owners.²¹ Once the development costs are recovered, PG&E will adjust the monthly per-tenant fee.

The special services fee would apply when a MHP owner requests a service that is not part of the Bill-Calculation Services.²² Under these circumstances, PG&E would determine the feasibility of the requested service and provide the MHP owner with a cost estimate of the requested service. PG&E would only perform the requested service upon mutual agreement. PG&E will track its actual costs and bill the MHP owner upon completion of the request.

As directed by D.04-11-033, the Joint Proposal includes a draft service agreement and draft tariffs. The proposed agreement includes a description of the Bill-Calculation Services; tenant bill information requirements; a minimum service term of 12 months; and other terms and conditions. The agreement must be signed by the MHP owner prior to receiving Bill-Calculation Services.

b. Discussion

D.04-11-033 required PG&E to submit in the current GRC the following information regarding bill-calculation services for MHP owners:

²¹ The Joint Parties estimate that approximately 814 MHP owners with 44,500 tenants will utilize PG&E's bill-calculation service.

²² For example, MHP owners may receive a one-time refund and ask PG&E to perform the bill calculations necessary to allocate each tenant's proportional share of the refund. In this case, the Special Services fee would be assessed per calculation, and would be in addition to the monthly per-tenant fee.

In their next revenue requirement proceedings, the electric and natural gas utilities shall provide an analysis of the costs, benefits, and feasibility of providing bill calculation services to MHP owners. The utilities shall also provide examples of the appropriate tariff language, and an estimate of the rates necessary to recover the full costs of such services from the MHP owners. (D.04-11-033, OP 12.)

We find that the Joint Proposal satisfies the requirements of D.04-11-033. Consistent with D.04-11-033, the cost of the proposed Bill-Calculation Services will be recovered from MHP owners. Thus, PG&E's other customers will not be affected by the proposed Services.

The proposed Bill-Calculation Services should provide several benefits. First, the proposed Services are substantially similar to SCE's bill-calculation services approved by D.06-05-016.²³ Thus, adoption of the proposed Bill-Calculation Services for PG&E will facilitate statewide consistency in utility bills among sub-metered MHP residents. The proposed Services should also promote statewide consistency between the bills that sub-metered MHP tenants receive and the bills that other utility residential customers receive.

Second, the proposed Services should facilitate the provision of timely and accurate monthly bills to MHP tenants. This will help MHP owners' compliance with § 739.5. Timely utility bills may also help MHP tenants make better decisions about their monthly energy usage.

Third, the proposed Services may be less costly than current methods used by MHP owners to calculate utility bills for sub-metered MHP residents.

²³ D.06-05-015, *mimeo.*, pp. 341-349.

Finally, bill-calculation issues raised by tenants might be reduced because (1) PG&E may be able to produce more accurate bills and more effectively process rate changes, refunds, and credits, and (2) PG&E will handle tenant bill-calculation questions. This, in turn, should reduce the number of complaints about MHP bills handled by the Commission, which should reduce the burden on the Commission's complaint process.

For the preceding reasons, we will adopt the unopposed Joint Proposal for MHP Bill-Calculation Services. To implement these Services, PG&E shall file an advice letter (AL) in time to begin offering the Services by June 1, 2007. The AL shall contain tariffs and a services agreement that are substantially similar to the proposed tariffs and agreement attached to the Joint Proposal. So long as the AL conforms to today's Opinion, the Energy Division may approve the AL without a Commission resolution.

3. Issues Raised by DRA

All issues raised by DRA regarding Customer Services were resolved by the Settlement Agreement. The following is a summary of the record concerning the issues raised by DRA.

a. Customer Inquiry Assistance

PG&E receives 17 million customer inquiries annually for service, information, and assistance. PG&E handles most customer inquiries through its call centers and the internet. For 2007, PG&E requested \$95.7 million for Customer Inquiry Assistance expenses and \$1.0 million for capital expenditures.

DRA proposed a disallowance of \$3.021 million of PG&E's requested expenses. DRA objected to a \$1 million budget transfer in 2005 and a \$2.021 million increase between 2006 and 2007 for unidentified internet projects. DRA did not contest PG&E's capital expenditures in this area.

PG&E responded that the \$1 million budget transfer opposed by DRA was exactly offset by another budget transfer going the other way, resulting in a net effect of zero. PG&E also contended that DRA's proposed disallowance of \$2.021 for unidentified internet projects was unfounded, as PG&E had provided a detailed, multi-page listing of the projects in its work papers.

b. Customer Care

PG&E requested \$41.1 million for Customer Care expenses in 2007. PG&E did not seek capital expenditures in this area.

DRA recommended three disallowances. First, DRA recommended a disallowance of \$0.26 million for Community Choice Aggregation (CCA) activities. DRA claimed that PG&E had failed to support the expenses because a PG&E data response referenced a blank line in its work papers. PG&E responded that its data response erroneously referred to page 3-5 of its work papers instead of page 3-4. On page 3-4 of its work papers, PG&E provided detailed information supporting the requested amount of \$0.26 million.

Second, DRA opposed \$0.215 million for expenses that are usually reviewed and recovered in other proceedings. PG&E responded that DRA did not question the reasonableness of the expenses, only the venue for their review and recovery. PG&E argued that the expenses in question are for Customer Services and belong in GRC proceedings with other Customer Services expenses.

Finally, DRA proposed a disallowance of \$0.50 million for increased numbers of customer satisfaction surveys on the basis that PG&E had not justified the additional surveys. PG&E responded that the increase in surveys was intended to help PG&E measure and improve customer service.

c. Gas Field Services and Dispatch Operations

Gas Service and Dispatch personnel respond to approximately 3 million customer service requests annually, such as stopping and starting service, pilot relights, appliance safety checks, emergencies, and maintenance work. PG&E requested \$100.3 million for Gas Service and Dispatch expenses in 2007 and \$14.1 million for capital expenditures.

DRA proposed two disallowances. First DRA recommended a disallowance of \$4.4 million for gas service representatives (GSRs), contending that PG&E sought to transfer staff into this function without justification. PG&E responded that DRA ignored some offsetting transfers of staff out of this function. PG&E also represented that DRA's proposal would reduce staffing for GSRs by 21 employees. According to PG&E, the elimination of 21 employees would "severely reduce PG&E's ability to respond to emergencies, to meet customer scheduling commitments...and to complete compliance work. Delayed response to customer requests caused by a reduction in manpower could force customers to attempt to address hazardous service issues themselves...putting themselves, as well as their communities, in dangerous situations."²⁴

Second, DRA recommended a disallowance of \$5.4 million of expenses for the Field Automation System (FAS) software upgrade. DRA argued that PG&E's existing software was good enough. PG&E responded that the upgrade was needed because the existing software is obsolete, costly to support, and lacks many of the features of the software upgrade that would help PG&E to maintain and improve customer service.

²⁴ Exhibit PG&E-18, pp. 27-3 to 27-4.

d. Emissions Reduction

PG&E's Emissions Reduction program includes an existing Low Emission Vehicle program and a proposed Low Emission Energy Services (LEES) program. PG&E requested \$12.3 million for expenses in 2007 for its Emissions Reduction program and \$3.53 million for capital expenditures. PG&E testified that these programs ensure that PG&E complies with regulatory requirements governing the operation of its fleet, are responsive to the Governor's Climate Change Executive Order, and could eliminate more than 1.3 million tons of carbon emissions at a cost below current market values.

DRA recommended two disallowances. First, DRA proposed a disallowance of \$1.975 million of capital expenditures for compressed natural gas refueling facilities. DRA believed that two of PG&E's four proposed refueling facilities were not justified because PG&E was uncertain of how many facilities it would install. PG&E responded that it had proposed a range of two to four facilities, but the actual number would depend on the cost of the locations selected. If PG&E selected more expensive locations, it would install fewer facilities, but its total costs would not go down as DRA assumed.

Second, DRA proposed a disallowance of \$3.641 million of expenses for the LEES program. For the most part, DRA argued that other parties, and not PG&E's ratepayers, should pay for the expenses requested by PG&E. PG&E responded that its requested expenses are cost effective for ratepayers and would provide significant environmental benefits.

e. Discussion

After reviewing the record, we conclude that the uncontested Settlement outcome for the issues raised by DRA regarding Customer Services is reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Issues Raised by Aglet, TURN, and Others

a. Billing, Revenue, and Records

PG&E's Billing, Revenue, and Records activities include the issuance of customer bills, maintenance of customer account information, payment processing, and revenue reporting. In 2004, PG&E issued over 66 million customer bills and 10 million late-payment notices.

PG&E initially requested \$92.1 million in 2007 for Billing, Revenue, and Records expenses and \$4.1 million for capital expenditures. TURN recommended averaging certain one-time expenses related to Energy Statement Redesign. PG&E agreed with TURN's recommendation. This concession reduced PG&E's request from \$92.1 million to \$89.9 million.

b. Customer Service Standards

PG&E presented data concerning its performance under the Quality Assurance Program and the Safety Net Program. PG&E did not request any changes to these programs or any expenses for these programs.

TURN did not raise any issues regarding existing standards, but TURN did propose a new standard. Specifically, TURN proposed a new "shut-off guarantee" that would require PG&E to pay \$100 to customers whose gas or electric service is erroneously shut off. PG&E was agreeable to TURN's proposal, although details must still be worked out, such as what constitutes an erroneous shut-off and when the program should start.

The Settling Parties agree that the Commission should adopt a new quality assurance standard for improper shut-offs and that the new standard should be explained via an advice filing to be made by PG&E within 90 days from today's

Opinion. Prior to making its filing, PG&E will meet with interested parties to resolve as many details of the new standard as practicable.²⁵

We find the Settlement outcome to be generally reasonable. The program provides two benefits: it provides compensation to the victims of error; and it provides a strong incentive to PG&E to avoid such errors. Our only concern is that the Settlement does not address who will pay for the new program. We conclude that because PG&E is the source of the error, PG&E should bear the cost of the program.

c. Critical Peak Pricing

i. Position of the Parties

PG&E requested \$0.52 million in 2007 for increased workload from the expected adoption of a new critical peak pricing (CPP) tariff by the Commission. TURN recommends that the Commission modify the Settlement Agreement to reduce PG&E's revenue requirement by \$0.52 million in 2007 for expenses associated with the CPP program. TURN believes the CPP expenses that PG&E seeks to recover in this GRC proceeding are duplicative of the CPP expenses that PG&E has sought to recover in either A.05-01-016 or A.05-06-006.

The salient issue, according to TURN, is whether PG&E notified the Commission in other proceedings that PG&E collects some CPP costs in GRCs. TURN does not believe that PG&E did so. Had the Commission been informed, TURN believes the Commission might have authorized lower amounts for the CPP budgets approved in other proceedings.

²⁵ Settlement Agreement, para. 23.

PG&E opposes TURN's recommendation and asserts that TURN has offered no evidence to support its allegation of double recovery of CPP costs.

ii. Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to reduce PG&E's revenue requirement for the CPP program by \$0.52 million in 2007. TURN's proposal rests on its assumption that CPP funding approved by the Commission in other proceedings might have been lower if the Commission had known that PG&E intended to recover some CPP costs through GRC proceedings. However, PG&E testified that there is no double recovery of CPP program costs,²⁶ and TURN has presented no evidence to contradict PG&E's testimony. In the absence of any evidence of double-counting, there is no basis to adopt TURN's recommendation.

d. Direct Access Service Fees

i. Position of the Parties

PG&E's current direct access (DA) service fees were set in 1999 and have not changed since. Because PG&E's costs have increased since 1999, TURN recommends that the Commission (1) increase DA fees by 30%, (2) impose an additional interim charge of \$5 on DA customers over 20kW, and (3) examine DA costs and rates in PG&E's rate design proceeding A.06-03-005.

TURN believes its recommendation is consistent with the Commission's decision in the recent SCE GRC proceeding where the Commission addressed the same issue. There, the Commission adopted TURN's proposal to increase SCE's DA fees by 25%. The Commission determined that it was better to adopt

²⁶ Exhibit PG&E-18, pp. 26-7 and 26-8.

TURN's proposed increase immediately rather than wait for SCE to file an application and continue the subsidization of DA customers by all other customers while the application was processed.²⁷

PG&E opposes TURN's proposal. The Settlement Agreement adopts PG&E's position and keeps DA fees at current levels.²⁸ The Settling Parties maintain that there is insufficient evidence in the record regarding whether, and to what extent, DA fees should be increased.

ii. Discussion

PG&E's DA fees have not changed since 1999 even though PG&E testified that its costs have risen significantly since then.²⁹ The Settlement Agreement leaves DA fees frozen at their 1999 level. If the fees were correctly calculated in 1999, and the costs have risen significantly since that time, then the fees are too low now. However, there is not enough information in the record to establish accurate, cost-based DA fees. Revising DA fees based on an incomplete record could result in above-cost fees, which would be just as harmful as below-cost fees.

For the preceding reasons, we decline to adopt TURN's proposal to increase DA fees by 30% and to impose an additional \$5 charge on DA customers over 20kW. To ensure that PG&E's DA fees are appropriately updated, we will require PG&E to provide an analysis of its DA costs in its next GRC.

²⁷ D.06-05-016, *mimeo.*, p. 110.

²⁸ Settlement, para. 26.

²⁹ Exhibit PG&E-8, p. 3-3, Table 3-2.

e. Read and Investigate Meters

i. Position of the Parties

PG&E obtains data from gas and electric meters through (i) human meter readers, and (ii) telecommunication technologies that obtain data remotely.

PG&E requested \$104.7 million for meter reading expenses in 2007.³⁰

TURN recommends that the Commission modify the Settlement Agreement to remove \$1.027 million for meter-reader employee turnover. These expense are not justified, according to TURN, because PG&E has meter-reader attrition of 20% annually. Thus, the cost for employee attrition should be captured in the base year and no additional adjustment to PG&E's 2007 expenses is necessary. TURN also argues that PG&E should have lower expenses in the future for meter-reader attrition because of the Advanced Metering Initiative (AMI) project, which will eventually replace most meter readers.

PG&E responds that it will have increased expenses for employee turnover because of its aging workforce. Because meter readers are entry-level positions, PG&E expects increased turnover of meter readers as they leave their positions for higher-level positions vacated by retirees.

ii. Discussion

The record shows that PG&E has experienced increased turnover among meter readers in recent years. In 2004, PG&E experienced 20% turnover, followed by 29% in 2005. PG&E testified that it expects 35% turnover in 2006 as more entry-level meter readers are promoted to positions vacated by

³⁰ PG&E reduced its requested meter reading expense in 2007 by \$0.068 million in response to TURN's proposed reduction for the Itron Maintenance Contract.

retirements.³¹ Based on this evidence, we conclude that PG&E's request for an additional \$1.027 million to hire and train meter readers in 2007 is reasonable.

We agree with TURN that PG&E's expenses for meter-reader turnover should decline after 2007 as meter readers are phased out due to the AMI program. Even so, the declining costs for employee turnover should be reflected in the Stipulated AMI Project Benefits adopted by the Commission in D.06-07-027.³² These benefits include anticipated reductions in employee-related costs associated with the AMI program. As a result, it would be double counting to reflect these declining costs in this GRC proceeding.

For the preceding reasons, we conclude that the Settlement outcome for meter-reading expenses is reasonable in light of the record, consistent with applicable law, and in the public interest.

f. Uncollectibles Factor

i. Position of the Parties

Uncollectibles expense is equal to the uncollectibles factor times billed revenue. PG&E requested authority to increase its uncollectibles factor from 0.002 to 0.002772.³³ DRA recommended 0.002582 based on a five-year average.

The Settlement adopts an uncollectibles factor of 0.002586.³⁴ The Settling Parties submit that this outcome is reasonable because it is the midpoint between

³¹ Exhibit PG&E-18, pp. 28-2 and 28-3.

³² D.06-07-027, *mimeo.*, pp. 29-30.

³³ The assigned ALJ removed from consideration in the instant proceeding PG&E's proposed 0.015% adder "to accommodate additional write-off as a result of implementation of the late payment fee." (Exhibit PG&E-5, p. 8-10.)

³⁴ Settlement Agreement, para. 20.

PG&E's request and Aglet's recommendation (discussed below), and is very close to DRA's recommendation.

Aglet recommends an uncollectibles factor of 0.00240, which is equal to the recorded value for 2005. Although the 2005 recorded uncollectibles factor was below PG&E's 19-year average, Aglet believes that PG&E can sustain its credit and collections success into 2007. This is because Aglet believes the uncollectibles factor has been trending down and that PG&E plans to implement measures that will keep the uncollectibles factor at its current low level.

PG&E responds that the 2005 recorded uncollectibles factor was unusually low relative to the five-year average of 0.002586 and the 19-year average of 0.0028, and will likely increase in 2007.

ii. Discussion

We find the uncollectibles factor of 0.002586 adopted by the Settlement is reasonable. The adopted uncollectibles factor is equal to the five-year average.

We are not persuaded by Aglet that it is better to use the 2005 recorded uncollectibles factor of 0.00240. We agree with PG&E's assessment that the 2005 uncollectibles factor was low relative to the five-year and 19-year averages, and will likely rise in 2007. In fact, PG&E testified that uncollectibles were growing in early 2006 due to increasing natural gas prices and the recent Winter Customer Care and Relief Program.³⁵ Although Aglet contends that PG&E has implemented measures that should enable PG&E to maintain its low 2005 uncollectibles factor, the supporting evidence cited by Aglet is unconvincing. Specifically, the PG&E exhibits cited by Aglet generally show that PG&E has

³⁵ Exhibit PG&E-18, p. 31-2, L: 17-24; 24 RT 2196:23 to 2197:5, PG&E/Torres.

taken steps to improve the efficiency of its Credit Operations in order to absorb increased workload without an increase in costs. In our opinion, there is no clear linkage between the steps taken by PG&E to improve its organizational efficiency and continuation of the relatively low uncollectibles factor in 2005. In any event, PG&E testified that it has suspended its efforts to improve the efficiency of its Credit Operations, which weakens Aglet's argument.³⁶

We conclude for the previously stated reasons that the Settlement outcome with respect to the uncollectibles factor is reasonable in light of the record, consistent with applicable law, and in the public interest.

g. Late-Payment Fee Implementation Expense

i. Position of the Parties

PG&E initially requested a total of \$0.481 million over 2007 - 2009 to implement a late-payment fee. Subsequently, issues regarding the late-payment fee were removed from this proceeding pursuant to a ruling by the assigned ALJ.

Aglet recommends that the Commission take steps to ensure that the revenue requirement adopted by today's Opinion excludes expenses for the late-payment fee. PG&E responds that Aglet's recommendation is moot because late-payment fee expenses were excluded from the Joint Comparison exhibit on which the Settlement Agreement is based.

³⁶ Exhibit PG&E-18, p. 31-4, L: 1-9; Exhibit PG&E-5, p. 8-5, L: 28-32. The suspension of PG&E's efforts to improve the efficiency of its Credit operations is driven by uncertainty regarding the outcome of the ongoing Billing and Collections phase of I.03-01-012.

ii. Discussion

On May 31, 2006, the assigned ALJ issued a ruling that removed from this proceeding all issues associated with PG&E's proposed late-payment fee and notified the parties that such issues would be considered, as appropriate, in I.03-01-012. We affirm the ALJ's Ruling.

Based on PG&E's representations, described above, we are satisfied that there are no late-payment fee expenses included in the revenue requirement adopted by today's Opinion. Aglet asks us to take unspecified measures to ensure that such costs are excluded from the adopted revenue requirement. We do not see a need for additional measures, since the costs in question are already excluded from the revenue requirement adopted by today's Opinion.

h. Service-Restoration Fee

i. Position of the Parties

Currently, when a customer's service is shutoff for nonpayment, PG&E charges a \$20 fee to restore service during regular hours and \$30 after hours. PG&E requested a phased increase in the service restoration fee to \$40.00 during regular business hours and \$60.00 during non-business hours to reflect PG&E's actual costs. DRA recommended that the fee increase be limited to 25% for reasons of affordability. DRA further proposed that CARE customers receive a 20% discount on the fee.

The Settling Parties agree that the service-restoration fee should be increased from \$20.00 during regular business hours and \$30.00 during non-business hours to \$25.00 and \$37.50, respectively. The Settling Parties also

agree that CARE customers should be exempted from the increase.³⁷ The Settlement essentially adopts DRA's position.

Aglet concurs with the Settlement for three reasons. First, Aglet agrees that a fee increase is necessary, but Aglet contends that PG&E's requested fee exceeded PG&E's actual costs for service restoration. Second, DRA's recommended 25% fee increase provides an orderly transition to cost-based rates. Finally, Aglet submits that it is reasonable to retain a higher fee for overtime and holiday work, which is generally more expensive than work done during regular hours. Aglet believes a single rate would send the wrong price signal, encouraging customers to seek reconnections outside of regular hours.

ii. Discussion

We find the uncontested Settlement outcome for the increased service restoration fee is reasonable for the reasons given by DRA and Aglet, is consistent with applicable law, and is in the public interest.

i. Non-Sufficient Funds Fee

i. Position of the Parties

PG&E requested authority to increase its fee for bounced checks from \$8.00 to \$11.50. The Settlement adopts PG&E's request.³⁸ The Settlement Agreement also requires PG&E to file, within 30 days, a compliance advice letter to implement the increased fee.

TURN does not oppose an increased fee. TURN observes that PG&E justifies the increased fee for bounced checks based on increased working-cash

³⁷ Settlement, para. 22.

³⁸ Settlement, para. 21.

expense. PG&E explains that it takes an average of 36 days for a replacement check to post after the initial check bounces, causing an average working-cash expense of \$4.13 per bounced check. TURN argues, however, that PG&E's proposed fee structure should be rejected because it ignores that working-cash costs vary with the size of the bounced check and, as a result, requires smaller customers to subsidize larger customers.

To remedy this inequity, TURN proposes a fee equal to \$6.50 plus 1% of the bounced check. TURN states that tying the fee to the amount of the bounced check results in customers paying a fee that reflects the actual costs they impose on PG&E. Under TURN's proposal, the average fee would be \$9.20 for residential customers and \$22.12 for non-residential customers.

TURN alternately proposes that separate flat fees be adopted for each customer class based on class-average costs. TURN believes a class-based flat fee would be easy for customers to understand, easy for PG&E to implement, and reduce the cross-subsidization among customer classes.

Although PG&E does not currently have a late-payment fee, the Commission is scheduled to consider the imposition of a late payment fee in another proceeding. TURN recommends that the Commission protect customers against possible double collection of working-cash costs by modifying the Settlement Agreement to indicate that any increase to the bounced-check fee will be reconsidered if a late-payment fee is instituted before PG&E's next GRC.

PG&E opposes TURN's proposals. First, PG&E asserts that TURN's variable fee of \$6.50 plus 1% of the bounded check would be confusing to customers and costly for PG&E to implement. Second, PG&E contends that TURN's alternate proposal for separate flat fees for each customer class is not adequately supported by record evidence. Finally, PG&E states that TURN may

raise its concerns about the possible double recovery of working-cash costs from the imposition of a late-payment fee in I.03-01-012 where the Commission is scheduled to address PG&E's proposal to implement a late-payment fee.

ii. Discussion

There is no dispute that PG&E's costs for bounced checks have increased and that PG&E should be allowed to establish a fee structure to recover the increased cost. The only dispute is the nature of the fee structure.

We find that the Settlement Agreement's adoption of an increased flat fee of \$11.50 is reasonable because it will enable PG&E to recover its rising costs for bounced checks, is easy for customers to understand, and will be less costly for PG&E to implement than other approaches.

We decline to adopt TURN's variable-fee because, as PG&E testified, it would be more confusing to customers than a flat-fee and more costly to implement than a flat-fee.³⁹

On the other hand, we find merit in TURN's alternative proposal for a separate flat fee for each customer class. We agree with TURN that such an approach would reduce the cross subsidies inherent in a single flat-fee, which is a worthwhile goal. However, as noted by PG&E, there is no supporting record for specific flat fees. Therefore, we decline to adopt class-specific flat fees at this time. We will revisit this issue in PG&E's next GRC. There, PG&E shall provide a separate, cost-based flat fee for each of the major customer classes and supporting work papers.

³⁹ Exhibit PG&E-18, p. 31-16, L: 17-27.

We decline to adopt TURN's proposal to modify the Settlement to state that the increased fee for bounced checks adopted today will be reconsidered if a late-payment fee is implemented before PG&E's next GRC. We intend to address PG&E's proposed late-payment fee in I.03-01-012.⁴⁰ TURN can raise in that proceeding its concerns about possible double recovery of working-cash costs from the imposition of both a late-payment fee and a bounced-check fee.

For the preceding reasons, we find the Settlement outcome for the bounced-check fee is reasonable in light of the record, consistent with applicable law, appropriately balances the interests at stake, and is in the public interest. As set forth in the Settlement, PG&E shall file a compliance advice letter within 30 days from the effective date of today's Opinion to implement the revised fee.

j. Customer Retention & Economic Development

i. Position of the Parties

(A) The Settlement Agreement

PG&E's Customer Retention and Economic Development program supports efforts to (1) retain customers, assets, and service territory that would otherwise be acquired by publicly-owned utilities; (2) attract, retain, or expand businesses that have the option to locate outside of PG&E's service territory; and (3) acquire the utility distribution facilities on military bases.

PG&E requested \$4.35 million in 2007 for Customer Retention and Economic Development expenses. The components of PG&E's request were as follows: (a) \$2.03 million for customer retention, (b) \$1.65 million for economic

⁴⁰ See Administrative Law Judge's Ruling Removing From This Proceeding All Issues Regarding Pacific Gas and Electric Company's Late Payment Fee, issued on May 31, 2006.

development, (c) \$0.35 million for acquisition of military facilities, and (d) \$0.32 million for regulatory/legislative activities. PG&E did not request capital expenditures in this area. DRA did not address this matter.

The Irrigation Districts opposed any ratepayer funding for customer retention and economic development. They argued that the primary purpose of PG&E's activities in this area is to combat the loss of service territory and customers to publicly owned utilities. In addition, Merced ID and Modesto ID called for an investigation of PG&E's implementation of Schedule E-31 to determine if abuses are occurring.⁴¹ Modesto ID also called for an investigation of PG&E's compliance with the Removal of Idle Facilities Agreement.⁴²

The Settlement resolves the disputes between PG&E and the Irrigation Districts by providing zero funding for customer retention, while continuing to fund economic development, acquisition of military facilities, and regulatory/legislative activities.⁴³ Additionally, Modesto ID and Merced ID agree to withdraw, for now, their requests for an investigation of PG&E's implementation of Schedule E-31.⁴⁴ Modesto ID also agrees to withdraw, for now, its request for an investigation of PG&E's compliance with the Removal of

⁴¹ Schedule E-31, Distribution Bypass Deferral Rate, was approved pursuant to § 454.1. This statute authorizes PG&E to offer discounted electric service when there is a competing, bona fide service offer from an irrigation district.

⁴² D.04-05-055, issued in PG&E's 2003 GRC proceeding, adopted the Removal of Idle Facilities Agreement that was signed by PG&E and Modesto ID. This Agreement requires PG&E to remove certain idle facilities and was intended to address Modesto ID's concern about PG&E leaving idle electric distribution facilities in place, and presumably in rate base, for long periods of time. The Agreement expires on December 31, 2006, unless PG&E and Modesto ID agree to extend it.

⁴³ Settlement Agreement, para. 19.

⁴⁴ Settlement Agreement, para. 50.

Idle Facilities Agreement in light of a commitment between the parties to negotiate possible revisions to that Agreement.⁴⁵

(B) Aglet

Aglet opposes the Settlement provisions that provide \$1.65 million of ratepayer funding for economic development. Alternatively, Aglet proposes a disallowance of \$0.50 million for trade shows, marketing, and economic development organizations.

Aglet observes that the objective of PG&E's economic development is to attract, retain, or expand businesses that have the option of locating outside of PG&E's service territory. Aglet opposes ratepayer funding of economic development because it is unrelated to the delivery of safe and reliable utility service. Nor is there any societal benefit, since one utility's loss is another's gain.

Aglet maintains that PG&E has not shown that it is cost effective for ratepayers to fund economic development. The Commission uses the ratepayer impact measure (RIM) to determine the cost effectiveness of economic development expenditures. The RIM is equal to the net present value of future revenues from business customers that are attributed to PG&E's economic development efforts, less PG&E's marginal cost to serve these customers and the cost of PG&E's Economic Development program.⁴⁶ Ratepayers benefit if the net present value exceeds zero. Aglet argues that PG&E's RIM calculations have two fatal flaws. First, Aglet presented information which purports to show that electricity costs are not crucial to most location decisions by California businesses. Aglet posits that 83% of the revenues that PG&E includes in its RIM

⁴⁵ Settlement Agreement, para 49.

⁴⁶ Exhibit PG&E-5, p. 9-15, Footnote 11.

calculations should be excluded to reflect the fact that electricity costs play a small role in business location decisions.

Second, Aglet asserts that PG&E's RIM calculations assume that the marginal cost to serve the business load that results from PG&E's economic development efforts will remain unchanged for the foreseeable future. The reality, according to Aglet, is that marginal costs will increase over time. If rising marginal costs are factored in, ratepayers are worse off under the RIM test.

(C) TURN

TURN opposes the Settlement's provision of \$1.65 million for economic development. TURN notes that the requested funding is double what PG&E was granted in its last GRC and double PG&E's recorded expenditures in 2004. TURN contends that PG&E has not justified a 100% increase in costs, choosing instead to fall back on the claim that the requested spending is warranted under the RIM test. As an alternative, TURN proposes that the Commission limit ratepayer funding for economic development to PG&E's expenditures in 2004.

TURN also opposes the Settlement's provision of \$0.32 million for regulatory/legislative activities tied to economic development. TURN believes these activities provide few or no benefits to ratepayers, duplicate the activities of other departments, and probably include below-the-line lobbying activities.

(D) PG&E and the Other Settling Parties

PG&E responds that its requested funding for economic development is consistent with Commission precedent. In D.05-09-018, which approved SCE's and PG&E's applications for economic development rates, the Commission made the following findings of fact:

1. The cost of electricity is a major cost of doing business in California. By some estimates electric rates cause about

one sixth of what some experts believe is the overall 30% cost premium for doing business in California.

2. The implementation of successful economic development projects benefits ratepayers by (a) increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers, and (b) providing increased employment opportunities and improved overall local and economic vitality.
(D.05-09-018, *mimeo.*, p. 27.)

Furthermore, the Commission explained:

Section 740.4(h) of the Pub. Util. Code requires the Commission to allow recovery through rates of expenses and rate discounts supporting economic development programs to the extent that ratepayers "derive a benefit from those programs." As the utilities have demonstrated, the implementation of successful economic development projects would benefit ratepayers directly by increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers.
(D.05-09-018, *mimeo.*, p. 13.)

The Commission also addressed ratepayer funding of economic development in SCE's most recent GRC proceeding. Citing the above-quoted findings in D.05-09-018, the Commission concluded that SCE's economic development program should be adopted with full ratepayer funding.⁴⁷

In rebuttal to TURN, PG&E states that its economic development activities do not include any below-the-line lobbying costs. This is because the work performed by the Economic Development organization is done by different

⁴⁷ D.06-05-016, *mimeo.*, p. 115.

people and is different in kind from the regulatory work undertaken by PG&E's Public Policy and Governmental Affairs personnel.

ii. Discussion

Ratepayer funding for economic development is subject to § 740.4(a). This statute states, "The commission shall authorize public utilities to engage in programs to encourage economic development." § 740.4(c) sets forth the scope of economic development activities, which include business expansion, relocation, retention, and recruitment. §§ 740.4(b) and 740.4(h) allow rate recovery of utility economic development expenses to the extent of ratepayer benefit.

There is no dispute that PG&E's economic development activities fall within the scope of § 740.4. In light of the guidance provided by § 740.4, we conclude that PG&E should be authorized to recover economic development expenses in 2007 as set forth in the Settlement Agreement, but only to the extent that such expenses benefit ratepayers. Consistent with Commission precedent, we will use the RIM test to evaluate ratepayer benefits.⁴⁸

PG&E's RIM calculations show that its economic development expenditures are cost effective for ratepayers, even if 95% of the businesses that benefit from PG&E's expenditures would have located in PG&E's service area absent such expenditures.⁴⁹ Aglet presents two criticisms of PG&E's RIM calculations, both of which are unpersuasive. First, Aglet contends that the revenues included in PG&E's RIM calculations should be reduced by 83% to reflect Aglet's claim that electricity costs are a minor factor in business location decisions. Aglet's criticism is moot, as PG&E's RIM calculations show that its

⁴⁸ D.95-06-016, Attachment 1, 60 CPUC2d 265, 277.

⁴⁹ Exhibit PG&E-5, p. 9-18.

Economic Development program is cost effective even if 95% of the businesses that benefit from the program are free riders.

Second, PG&E's RIM calculations assume that the marginal cost to serve the load that results from PG&E's economic development efforts will remain unchanged for the foreseeable future. Aglet contends that if rising marginal costs are factored in, ratepayers would be worse off under the RIM test. However, Aglet overlooks the fact that PG&E also used the same marginal revenue throughout this period.⁵⁰ While we agree with Aglet that marginal costs will probably rise over the 10-year period reflected in PG&E's RIM calculations, it is just as likely that PG&E's marginal revenue will increase as well. We believe that PG&E's RIM calculations would show that PG&E's economic development expenditures are cost effective for ratepayers if both rising marginal costs and rising marginal revenues are factored in.

TURN criticizes the RIM test for economic development expenditures, claiming that PG&E should "demonstrate that each new expenditure will yield ratepayer benefits rather than hiding behind an overall RIM test analysis for the aggregate spending level."⁵¹ We disagree. The Commission previously held that the following standards set forth in D.95-06-016 should be used to evaluate the cost-effectiveness of utility economic-development programs⁵²:

[All] cost-effectiveness and program analysis should be conducted at the end use level, as defined for each program by the protocols governing the measurement and evaluation

⁵⁰ PG&E's RIM calculations used a marginal cost of \$0.0549/kWh and a marginal revenue of \$0.12200/kWh. (Exhibit PG&E-5-WP09, p. 9-24.)

⁵¹ TURN's comments on the Settlement Agreement, p. 37.

⁵² See, for example, D.04-07-022, 2004 Cal. PUC LEXIS 325, *208.

of...programs, as well as the program as a whole. The “program as a whole” includes any miscellaneous measure for which an end use is not designated for measurement. If the adopted measurement protocols do not specify or require measurement at the end use level, cost-effectiveness analysis should be applied at the level of the program as a whole. (D.95-06-016, Attachment 1, Fn. 2.)

Using the criteria in the above-cited decision, we find that because PG&E’s Economic Development program as currently structured contains no-end use elements, the “program as a whole” standard should apply to PG&E’s economic development expenditures. This is what PG&E did in its RIM test calculations.

For the preceding reasons, we find that PG&E’s requested economic development expenditures are cost effective for PG&E’s ratepayers, and that PG&E should be allowed to recover all of its requested expenses for economic development pursuant to § 740.4. We decline to adopt Aglet’s alternate recommendation to disallow \$0.50 million for trades shows, marketing, and economic development organizations. These activities appear to be an important element of PG&E’s Economic Development program, and failure to fund these activities would likely diminish the effectiveness of the program.⁵³

For the same reason, we decline to adopt TURN’s proposals to (1) limit funding for PG&E’s economic development to the 2004 recorded level of \$0.97 million, and (2) disallow \$0.32 million of requested funding for the

⁵³ PG&E’s RIM calculations do not appear to have included \$0.50 million for trade shows, marketing, and economic development organizations. However, because PG&E’s calculations show \$3.48 million of net benefits at a 95% free rider rate (Exhibit PG&E-5, p. 9-16), the inclusion of an additional \$0.50 million of costs in the RIM calculations would not change our conclusion herein that PG&E’s economic development expenditures are cost effective for ratepayers.

regulatory/legislative component of PG&E's Economic Development program. We caution PG&E that it should not use any economic development funds to engage in below-the-line lobbying activities. We expect PG&E to keep records that demonstrate no below-the-line lobbying was funded with economic development funds.

5. Conclusion re: Customer Services

Based on our review of the record, we conclude that the Settlement Agreement provisions regarding Customer Services are reasonable in light of the record, consistent with the law, and in the public interest.

B. Electric Distribution

1. Electric Distribution Revenues

DRA was the only party that presented testimony on PG&E's present and forecasted electric retail revenues. DRA and PG&E agreed on forecasted billings, sales, and electric revenues at present rates.

Modesto ID questioned PG&E's treatment of non-bypassable charges for departing load customers in the computation of revenues at present rates. PG&E responded that departing load customers are not included in the computation of GRC revenues; these computations deal strictly with retail revenue accounts.

The Settlement adopts PG&E's forecasts of Electric Distribution billings, sales, and revenues at present rates. There is no opposition to the Settlement outcome on this matter. We concur with this outcome.

2. Electric Distribution O&M Expenses

PG&E requested \$494 million for Electric Distribution operation and maintenance (O&M) expenses in 2007. DRA proposed \$462 million, for a difference of \$32 million. TURN also proposed several disallowances.

The Settlement Agreement adopts \$489 million. The following table compares the Settlement outcome to PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Electric Distribution O&M Expenses (\$ millions)							
		Comparison Exhibit			Variances Increase/(Decrease)		
	2006 Authorized	PG&E	DRA	Settlement	Settlement vs. 2006	PG&E vs. Settlement	DRA vs. Settlement
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
O&M	443.9	494.2	461.7	488.8	44.9	(5.4)	27.1
Source: Settlement Agreement, Appendix B, Line 1.							

The Settling Parties agree that the O&M labor factors for all of PG&E's lines-of-business (e.g., gas, electric, and generation) in this proceeding and others will be calculated from 2004 recorded adjusted O&M labor.⁵⁴

Below, we assess the reasonableness of Settlement outcome for Electric Distribution O&M expenses in light of the record on the issues raised by DRA and TURN.

a. Issues Raised by DRA

All issues raised by DRA regarding Electric Distribution O&M expenses were resolved by the Settlement Agreement. The following is a summary of the record concerning the issues raised by DRA.

⁵⁴ Settlement Agreement, para. 52.

i. Issues Other than Vegetation Management

(A) Distribution Line Equipment Inspect and Test

DRA recommended a disallowance of \$0.6 million of PG&E's requested expenses in 2007 for Distribution Line Equipment Inspect and Test. PG&E responded that DRA's proposed disallowance, which was based on a three-year average of data for 2002 - 2004, did not reflect a sharp increase in work in 2005. DRA agreed that data for 2005 indicated a need to increase its forecast of work in 2007, but the parties disagreed on how to adjust the forecast.

(B) Preventative Maintenance

Preventive Maintenance consists of 18 categories of work, three of which were disputed by DRA at the time of the Comparison Exhibit.

(1) Overhead Repairs

PG&E requested \$28.5 million for Overhead Repair expenses in 2007. PG&E testified that in 2005 the resources normally assigned to maintenance work were shifted to higher priority work, such as emergency response, storms, and new business. Consequently, PG&E's request for 2007 included work that was rescheduled from 2005.

DRA accepted PG&E's forecast of unit cost, but disputed PG&E's forecasted units of work in 2007. DRA used a four-year average of work during 2002 - 2005 to arrive at its forecast of \$23.3 million for 2007, which was \$5.2 million less than PG&E's request. PG&E responded that it must perform the rescheduled maintenance work in 2007, and that DRA's averaging technique did not capture the need to perform the rescheduled work in 2007.

(2) BG Projects

BG Projects covers preventive maintenance work that is infrequent or of a limited duration. PG&E requested \$3.0 million annually for BG Projects during

2007, 2008, and 2009. Of this amount, \$2.2 million was for specific projects that had already been identified, and the rest was for projects that have yet to be identified. DRA recommended a total of \$2.2 million during 2007-2009 for only those projects that had already been identified, with no placeholder for projects that could not be identified years in advance.

(3) Other

The Other category consists of special projects that, if grouped in other categories, would skew units and unit costs. PG&E requested \$1.2 million for Other work in 2007. DRA proposed \$0.4 million, for a difference of \$0.8 million. PG&E's forecast was based on specific projects that had been identified for 2007. DRA's forecast was based on the four-year average of expenses during 2002 - 2005. PG&E responded that (1) the 2002 accounting data is anomalous because of a credit that corrected an error from the previous year, and (2) recorded expenses showed a clear upward trend in recent years.

(C) Pole Asset Management

Pole Asset Management expenses consists of three categories of work. PG&E and DRA agreed on PG&E's 2007 request of \$1.7 million for Pole Engineering and \$6.3 million for Pole Restoration. The only dispute involved Pole Test and Treat expenses. PG&E requested \$12.7 million for these expenses in 2007. DRA recommended \$11.9 million, for a difference of \$0.8 million.

DRA and PG&E disagreed on the forecast of work on inaccessible poles. DRA accepted PG&E's 2007 forecast unit cost of \$125, but argued that only 6,000 poles need to be addressed, rather than PG&E's 2007 forecast of 12,710 poles.

PG&E responded that its Pole Test and Treat program is based on a ten-year cycle. When contractors work their assigned lists of poles to test and treat each year, they encounter poles that are not accessible for a variety of

reasons, such as locked gates, dogs, customer not home, etc. PG&E's contractors identified approximately 35,000 such poles in prior years.

PG&E testified that it needs to complete the final 12,710 poles in 2007 to remain in compliance with General Order (GO) 165, which requires utilities to test and treat all wood poles over 15 years old once every 10 years. This 10-year deadline did not exist prior to 2007, as GO 165 was adopted in 1997.

(D) Externally Driven Work

Externally Driven Work covers two areas: (1) New Customer Connection expenses, and (2) Work Requested by Others (WRO). There were no disputes regarding the first area.

PG&E and DRA disagree on WRO expenses for pre-parallel inspections.⁵⁵ PG&E requested \$0.7 million for pre-parallel inspection expenses in 2007, which was based on historical costs of \$662,000 in 2004 escalated by 3% annually. DRA objected to any ratepayer funding for pre-parallel inspections because PG&E had not provided historical data aside from 2004 costs.

PG&E responded that prior to 2005, pre-parallel inspection expenses were recorded in transmission accounts, and this was the reason historical data had not been provided in response to DRA's data request.

(E) Conclusion

The Settling Parties agree that the resolution of the previously identified issues raised by DRA is subsumed in the Settlement outcome for Electric

⁵⁵ PG&E and DRA initially had two other areas of dispute regarding WRO expenses. In rebuttal, PG&E agreed with DRA's \$10.2 million forecast for relocations, and PG&E agreed to reduce its GIS forecast from \$3.5 million to \$1.6 million. At hearings, DRA's witness agreed with PG&E's revised GIS forecast.

Distribution O&M expenses. Based on our review of the record regarding these issues, summarized above, we find that PG&E has provided reasonable justification for virtually all of the expenses contested by DRA. The Settlement outcome for Electric Distribution O&M expenses is consistent with our conclusion, in that the Settlement adopts a higher amount for Electric Distribution O&M expenses than recommended by DRA.

ii. Vegetation Management

PG&E requested \$154.4 million in 2007 for its Vegetation Management program. PG&E also sought to convert the one-way Vegetation Management Balancing Account to a two-way balancing account due to the significant costs that may be needed to comply with recent interpretations of utility obligations under Pub. Resources Code § 4293 by the California Department of Forestry and Fire Protection (CDF).

DRA disagreed with PG&E's requested expenses and PG&E's proposal to convert the one-way Vegetation Management Balancing Account to a two-way balancing account. No other parties addressed this matter. The areas where PG&E and DRA disagreed are summarized below.

(A) Routine Tree Trimming & Removal

PG&E requested \$136.7 million in 2007 for Routine Tree Trimming & Removal expenses. DRA proposed \$124.6 million, for a difference of \$12.1 million. PG&E calculated its 2007 expenses by multiplying its forecast of 1,580,191 units by its forecasted unit cost of \$86.51. DRA accepted PG&E's forecast of units but used a lower unit cost of \$78.83.

Contract work is the largest expense in this area. PG&E testified that contractor prices are increasing, as demonstrated by the 7.8% increase in contractor prices in 2006 compared to 2005. The reasons for the increased prices

include (1) higher costs for labor, insurance, fuel, and environmental compliance, and (2) an increase in the ratio of overhead line miles to tree volume.

DRA used the weighted average of unit cost increases from 2000 to 2005 to forecast unit costs for 2007. DRA's forecasted unit cost of \$78.83 in 2007 represented an increase of 1.6% over 2006.

(B) Increased Staffing

PG&E requested \$0.7 million in 2007 to increase its Vegetation Management staff from 51 to 58 full-time PG&E employees. The requested new staff consisted of one quality assurance specialist and six tree-trimming foresters. DRA proposed a disallowance of \$0.3 million. DRA accepted PG&E's request for one additional quality assurance specialist but recommended only three additional tree-trimming foresters. DRA asserted that its proposed staff increase was sufficient in light of PG&E's compliance level of 99%.

PG&E responded that it was striving not only for excellent compliance statistics, but also to improve customer service and agency relationships.

(C) Recovery of CDF-Mandated Costs

PG&E expressed concern regarding the recovery of costs that could result from the CDF's push to have PG&E substantially increase its inspection, assessment, and removal of trees and limbs. PG&E believes this work is unwarranted and is working with the CDF to allay its concerns. However, if the CDF's current position prevails, PG&E testified that the cost of the Vegetation Management program could increase by \$50 million per year.

DRA agreed that ratepayers should fund work required by the CDF. The only disagreement was whether the Commission should establish a two-way balancing account with automatic flow through of CDF-mandated costs as

proposed by PG&E, or a memorandum account in which PG&E could record CDF-mandated costs and later seek to recover these costs as proposed by DRA.

(D) The Settlement Agreement

The Settlement provides \$150 million for Vegetation Management expenses. This outcome is \$4.5 million less than PG&E requested and \$8.0 million more than DRA recommended. The Settlement also keeps the Vegetation Management Balancing Account as a one-way balancing account, and allows PG&E to track and recover costs for additional work required by the CDF via a new memorandum account established through the advice letter process.⁵⁶

(E) Discussion

In light of the record evidence recounted above, we find the Settlement outcome for Vegetation Management is reasonable, consistent with the law, and in the public interest. The Settlement expense amount of \$150 million is supported by the record. With the one-way balancing account, any part of the \$150 million that is not needed for Vegetation Management will be refunded to ratepayers. In addition, the Settlement provisions that permit PG&E to track and recover additional costs for specified CDF actions through an advice filing, subject to audit, are a reasonable compromise of DRA's and PG&E's litigation positions and fairly balance ratepayers' and shareholders' interests.

iii. Other Electric Distribution O&M Expenses

PG&E and DRA agreed on the amount of Electric Distribution O&M expenses in 2007 for the following areas:

⁵⁶ Settlement Agreement, para. 18.

Other Electric Distribution O&M Expenses - Areas Where PG&E and DRA Agree	
Description	2007 (Millions)
Operation/Maintain Substation	\$27.0
System Automation Maintenance	\$3.3
Corrective Maint. Expense	\$50.6
Electric Distrib. Major Emergency	\$10.9
Electric Engineering and Planning	\$19.1
Electric Mapping	\$10.9
Develop and Provide Training	\$0.8
Maintenance of Other Equipment	\$4.2
Operate Electric Distribution	\$32.4
Total	\$159.20

There is no opposition to PG&E's requested expenses in the above table. We find that DRA's review and concurrence with the above costs, combined with the lack of opposition, lends weight to the Settlement outcome that adopts almost all of PG&E's requested Electrical Distribution O&M expenses.

b. Issues Raised by TURN

i. Double Recovery of AMI-Related Costs

(A) Position of the Parties

PG&E testified that the only area where it requested duplicative costs in both this GRC proceeding (A.05-12-002) and the AMI proceedings (A.05-06-028 and A.05-03-016) was Information Technology (IT). The Settling Parties agree that PG&E has removed the duplicative IT costs from this GRC proceeding,⁵⁷ and

⁵⁷ The specific amounts removed are shown in Appendix G of the Comparison Exhibit. (Exhibit PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.)

that the Settlement eliminates double recovery of IT costs. The Settling Parties further agree that all AMI program costs and benefits will be addressed through the AMI balancing accounts established pursuant to D.06-07-027.⁵⁸

TURN remains concerned about double recovery of AMI program costs. Although the Commission directed PG&E to track AMI program costs and benefits through balancing accounts,⁵⁹ TURN believes this will not prevent double recovery. To safeguard ratepayer interests, TURN recommends that the Commission require PG&E to list and audit all expenses and capital expenditures requested in this GRC proceeding that might also be recovered through the AMI program or have to be written off because of the AMI program.

To demonstrate the need for such an audit, TURN cites PG&E's request in the instant GRC proceeding to install and maintain a significant number of residential time-of-use (TOU) meters. Now that the Commission has approved PG&E's AMI program, TURN states that the Commission must consider the risk of authorizing TOU meter costs in this GRC that could be stranded in a few years. TURN posits that simply having a balancing account to track AMI program costs and benefits does not address such concerns.

PG&E opposes TURN's recommendations. PG&E contends that the AMI proceeding addressed all costs and benefits that are incremental to PG&E's GRC. Further, D.06-07-027 requires all AMI program costs and benefits to be tracked and accounted for separately from normal GRC-related operations and costs.⁶⁰

⁵⁸ Settlement Agreement, para. 20.

⁵⁹ D.06-07-027, FOF 17, Conclusion of Law (COL) 8, and Ordering Paragraph (OP) 2.

⁶⁰ D.06-07-027, *mimeo.*, p. 47.

(B) Discussion

We agree with TURN that it is prudent to closely monitor PG&E's \$1.7 billion AMI program. However, we do not believe it is necessary to adopt new requirements at this time regarding oversight of PG&E's AMI program. In D.06-07-027, we ordered PG&E to provide testimony in its next GRC regarding AMI program costs and benefits.⁶¹ TURN will have an opportunity to conduct full discovery at that time on all issues that would otherwise be addressed in TURN's proposed audit. We appreciate TURN's watchdog role, and we encourage TURN to avail itself of the opportunity in the next GRC to carefully scrutinize PG&E's AMI program for duplicative and stranded costs.

For the preceding reasons, we decline to adopt TURN's recommendation to order PG&E to list and audit its AMI program costs.

ii. TURN's Alternate Proposal for TOU Meter Expenses

(A) Position of the Parties

PG&E requested \$16.5 million in 2007 for expenses to install electric meters. TURN's primary recommendation, which is addressed, *supra*, is to reduce PG&E's request by \$7.6 million. TURN's alternative proposal, which is addressed here, is to reduce PG&E's request by \$1.8 million. The Settling Parties agree that the resolution of TURN's proposed reduction of \$1.8 million is subsumed in the Settlement outcome for Electric Distribution expenses.⁶²

TURN observes that PG&E's request for meter installation expenses in 2007 includes \$1.4 million to offset the elimination of the residential TOU meter

⁶¹ D.06-07-027, FOF 20 and OP 15.

⁶² Settlement Motion, p. 33.

installation charge in 2006. PG&E assumed that it would install 5,000 residential TOU meters annually during 2007 through 2009, while not receiving the \$277 per-meter installation charge as it has in previous years. TURN submits that the AMI program will reduce and eventually eliminate TOU meter installations. As result, TURN believes that PG&E's forecast of TOU meter installations is too high, and recommends that the Commission modify the Settlement Agreement to remove the \$1.4 million.

PG&E also requested \$0.4 million for capital expenditures in 2007 to install 5,000 RTOU meters annually during 2007-2009. TURN recommends that the Commission modify the Settlement Agreement to deny PG&E's request to prevent these capital expenditures from being stranded as TOU meters are replaced under the AMI program.

Finally, PG&E forecasted a net increase in TOU meters from 11,671 in 2004 to 20,700 in 2007. TURN states that it would be imprudent to forecast a corresponding increase in maintenance costs for TOU meters that will likely be replaced during the GRC cycle as a result of PG&E's AMI program.

PG&E opposes TURN's recommendations. PG&E forecasts an increase in the number of installed TOU meters during the GRC cycle and, as a result, PG&E will incur higher maintenance and other costs. At the same time, because the Commission has eliminated the installation fee for TOU meters, PG&E will have less revenue to offset costs related to TOU meters.

(B) Discussion

The premise of TURN's proposed disallowance is that PG&E will not incur its forecasted level of expenses and capital expenditures for TOU meters during the GRC cycle because TOU meters will be replaced over the next few years by

the AMI program. We agree that TOU meters will eventually be replaced, but until that occurs PG&E will continue to have TOU-related costs.

PG&E testified that current demand for TOU meters is strong, and PG&E forecasts a net increase of 5,000 TOU customers annually through 2007. The strong demand is likely fueled, in part, by the elimination of the TOU meter installation charge by D.05-11-005.⁶³ PG&E must meet that demand, as PG&E is required by its tariffs to provide TOU service to customers that request it.⁶⁴

For the preceding reasons, we decline to adopt TURN's proposal to reduce PG&E's revenues requirement for TOU meters. Moreover, the proposal is largely moot, as any savings from the replacement of TOU meters should already be reflected in the Stipulated AMI Project Benefits adopted by D.06-07-027.

iii. Cessation of TOU Meter Installations

(A) Position of the Parties

TURN recommends that the Commission order PG&E to stop installing TOU meters because the newly installed TOU meters will be replaced within a few years by PG&E's AMI program. PG&E responds that it cannot not stop installing TOU meters because it is required by its tariff to provide a TOU meter to any customer who requests it. TURN replies that PG&E should file a petition to modify the decision directing PG&E to install TOU meters.

(B) Discussion

We decline to adopt at this time TURN's proposal to require PG&E to stop installing TOU meters. TURN did not address what effect its proposal might

⁶³ D.05-11-005, *mimeo.*, pp. 9, 10, and 33.

⁶⁴ Exhibit PG&E-15, pp. 21-3 and 21-4.

have on the Commission's policy of relying on demand side management (DSM) as one way to reduce the need for new generation resources and to combat global climate change. TOU meters advance the Commission's policy. We share TURN's concern about the cost-effectiveness of TOU meters in light of PG&E's impending AMI roll out, but TURN's proposal to cease installing TOU meters needs to be evaluated in the context of our policy of promoting DSM. We do not have a sufficient record to do so here.

iv. Forecasted Meter Expenses for 2007

(A) Position of the Parties

PG&E records expenses to install electric meters in its internal account Major Work Category (MWC) EY - Install Electric Meters and Devices. PG&E initially requested \$17.1 million for MWC EY in 2007, but subsequently agreed to two reductions: (1) DRA's reduction of \$0.335 million to normalize costs for Analog Cell Phone Replacement over the three-year GRC, and (2) TURN's reduction of \$0.238 million to normalize costs for the Agricultural Diesel Irrigation Pumping Conversion program over the three-year GRC. These two adjustments reduced PG&E's request for MWC EY in 2007 to \$16.5 million. With these two adjustments, PG&E and DRA no longer had any disputes regarding MWC EY, but PG&E and TURN continued to disagree on other aspects of MWC EY.

TURN submits that PG&E's request for \$16.5 million is unreasonable because it is 229% higher than 2005 recorded costs of \$7.2 million. TURN recommends that the Commission modify the Settlement to set PG&E's revenue requirement for MWC EY in 2007 at \$9.2 million, which is \$7.3 million less than PG&E requested. TURN's proposal is equal to PG&E's average annual costs for 2004 and 2005 escalated to 2007 by customer growth of 1.6% annually.

PG&E responds that TURN's reliance on 2004 and 2005 recorded expenses fails to capture significant additional expenses in 2007. PG&E provided four examples to demonstrate this point. First, PG&E's recorded expenses in 2005 were reduced by \$3 million due to increased capitalization of labor costs associated with a concerted effort to replace obsolete meters. PG&E forecasts a more normal meter replacement effort in 2007, resulting in a \$3 million increase in expenses (and a corresponding \$3 million reduction in capitalized labor costs).

Second, in D.05-11-005 the Commission eliminated the installation charge for TOU meters, thereby reducing PG&E revenues by \$1.4 million in 2007 relative to 2004. These revenues were previously used to offset PG&E's revenue requirement for MWC EY. PG&E states that it must recover the lost revenue in 2007 through a higher revenue requirement for MWC EY.

Third, PG&E forecasts a significant increase in the number of TOU meter installations in 2007 because of the elimination of the installation charge, which will cause a corresponding increase in installation expenses.

Finally, PG&E forecasts a substantial increase in electric meter installations for agricultural customers in light of the State's policy to reduce air pollution by converting diesel-powered irrigation to utility electric service as part of the Agricultural Diesel Irrigation Pumping Conversion (Ag-ICE) program.

(B) Discussion

PG&E requested an increase of 229% for MWC EY expenses in 2007 compared to recorded costs in 2005. We find that PG&E has justified most of this increase for the reasons summarized above, but not all of the increase.

The Settling Parties agree that the resolution of this matters is encompassed within the Settlement outcome for Electric Distribution expenses for O&M and Customer Services.⁶⁵ The Settlement Agreement adopts a revenue requirement of \$736 million in 2007 for Electric Distribution expenses for O&M and Customer Services, which is \$9 million less than PG&E requested and \$29 million more than DRA recommended.⁶⁶ We conclude that the portion of MWC EY expenses that PG&E has not justified is subsumed in the Settlement's reduction of PG&E's requested Electric Distribution expenses.

For the preceding reasons, we find the Settlement outcome for MWC EY is reasonable in light of the record. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to reduce funding for MWC EY.

v. Revised Accounting for Meters

(A) Position of the Parties

PG&E records its costs for electric and gas meters in its internal expense accounts MWC EY (electric) and MWC HY (gas). Some of these costs are eventually transferred to, and capitalized in, the internal asset accounts MWCs 25 (electric meters) and 74 (gas meters). TURN contends that PG&E should capitalize meter costs in MWCs 25 and 74 immediately without clearing them through MWCs EY and HY. TURN believes its recommendation would allow parties and the Commission to more easily evaluate whether PG&E's meter expenses and capitalized costs are reasonable.

⁶⁵ Settlement Motion, p. 33.

⁶⁶ Settlement Motion, p. 21, Table 3; Settlement Agreement, Appendix B, p. 24, L: 1, 2.

PG&E opposes TURN's recommendation and states that it properly accounts for capitalized meter costs.

(B) Discussion

TURN has not shown that PG&E's accounting is erroneous. We decline to meddle with PG&E's internal accounting system by adopting TURN's proposal. It appears that PG&E has provided to TURN and the other parties sufficient information to enable them to understand and analyze PG&E's meter expenses and capitalized meter costs. We expect PG&E to do so again in its next GRC.

c. Conclusion

Based on our review of the record, we conclude that the Settlement Agreement outcome for Electric Distribution O&M expenses is reasonable in light of the record, consistent with the law, and in the public interest.

3. Electric Distribution Capital Expenditures

PG&E requested \$862.0 million for Electric Distribution capital expenditures in 2007. DRA recommended \$816.9 million, for a difference of \$45.1 million. No other parties addressed this matter. The Settlement adopts PG&E's request.⁶⁷

There is no opposition to the Settlement outcome on this matter. Below, we review the record regarding the issues raised by DRA in order to assess the reasonableness of the Settlement outcome for Electric Distribution capital expenditures.

⁶⁷ Settlement Agreement, Appendix G, Table 4-1.

a. Summary of the Record

i. Pole Asset Management

PG&E requested \$94.1 million to replace 15,000 utility poles in 2007 at a unit cost of \$6,276. DRA recommended a 5% reduction in the unit cost and a reduction of 1,000 in the number of units, resulting in a forecast of \$83.5 million.

PG&E responded that DRA's proposed reduction in unit costs ignored the shift that has occurred in the location of the poles to be replaced. PG&E represented that it will be replacing relatively more poles in the high-cost urban areas, thereby increasing costs above historical levels.

PG&E further contended that DRA's forecast of replacing 14,000 poles annually failed to address the "bubble" of pole replacements that must be done to stay in compliance with safety standards set forth in GO 95 and to proactively address aging infrastructure.

ii. Undergrounding Projects

PG&E requested \$55 million for capital expenditures in 2007 for undergrounding projects. DRA proposed a \$5 million disallowance based on past spending. PG&E responded that historical spending should not be used to estimate future expenditures in this area because historical spending had been suppressed by the energy crisis, PG&E's bankruptcy, and the need to fund higher priority projects.

iii. Tie-Cable Circuits

Tie-cable circuits connect distribution substations together. Most tie-cables are more than 40 years old. PG&E requested \$19.1 million for capital expenditures in 2007 to replace tie-cables. DRA proposed \$10.9 million, for a difference of \$8.2 million. DRA believed that a lower level of spending was appropriate given that tie-cables are reliable and are usually operated in parallel.

PG&E responded that its tie-cables are failing with increasing frequency because of their age. PG&E explained that because tie cables are a crucial part of its distribution system, the aging tie cables need to be replaced expeditiously to maintain system reliability. PG&E's expert witness explained why higher spending is prudent:

Although the failure of a single tie-cable will not generally lead to any customer interruptions, the failure of multiple tie cables could lead to a very large number of interruptions. The probability of two tie-cable outages occurring at the same time increases with the square of cable failure probability. If tie-cable failure rates increase by a factor of five, the probability of customer interruptions will increase by a factor of twenty-five. For this reason, deteriorated tie-cables at PG&E should be given a high priority for proactive replacement.
(Exhibit PG&E-4, p. 18-39, para. 3.)

PG&E asserted that the amount of tie-cable that needs to be replaced is known and the cost to replace the cable is not disputed. PG&E contended that its request for \$19.1 million is consistent with its 2005 recorded expenditures of \$17.8 million. PG&E also stated that DRA's forecast represented only 61% of what PG&E spent in 2005 and 54% of what PG&E planned to spend in 2006.

iv. Plastic Insulated Cables

PG&E requested \$13.875 million for capital expenditures in 2007 to replace plastic insulated cables. DRA proposed \$5.074 million, for a difference of \$8.801 million. DRA offered three reasons to support its forecast. First, DRA believes there is insufficient data on exactly when and where PG&E intends to replace plastic insulated cables. Second, the settlement reached in the Mission Substation Fire OII calls for a consultant's report on PG&E's system reliability,

and this report may provide guidance on where funds should be spent. Finally, the most PG&E has ever spent on this activity is \$4.630 million in 2003.

PG&E responded that it already knows, for the most part, when and where it will replace plastic insulated cable in 2007. PG&E also asserted that the consultant report from the Mission Substation OII is unlikely to provide new guidance as to where PG&E's capital expenditures should best be spent because (1) the report is limited to San Francisco, and (2) the study is not designed to analyze the optimization of plastic insulated cable replacement, but to identify ways to improve reliability overall.

PG&E disputed DRA's use of historical spending to forecast future capital expenditures in this area. PG&E asserted that two consultant reports found that PG&E needs to replace 300 to 400 miles of cable annually to maintain system reliability. PG&E's proposed expenditures, although large compared to historical spending, will replace less than 50 miles per year.

v. Lead Cables

PG&E requested \$8.70 million for capital expenditures in 2007 to replace paper insulated lead covered cables (PILC). DRA proposed \$2.03 million, for a difference of \$6.67 million. DRA raised four arguments in support of its recommendation. First, PG&E needs more data to optimize expenditures. Second, a forthcoming consultant's report required by the Mission Substation Fire OII settlement will likely provide guidance as to where PG&E should make its capital investments. Third, lead cables are reliable. Finally, the largest amount PG&E has spent in this category was \$1.83 million in 2004.

PG&E responded that historical expenditures in this area are not a good predictor of future requirements. Most PILC is at least 40 years old, and PILC failures have increased sevenfold in the last 20 years. PG&E believes the

growing rate of failures shows a need for capital expenditures above historical levels, and that no additional data is needed to support these investments.

PG&E acknowledged that the consultant's report from the Mission Substation Fire OII might provide additional guidance as to where PG&E's capital expenditures for PILC replacement would be best spent. However, PG&E argued that it has already identified a great deal of work, and that the consultant's report could recommend an increase in expenditures.

vi. Other Electric Distribution Capital Expenditures

PG&E requested \$6.6 million in 2007 to repair equipment. DRA proposed \$4.7 million, for a difference of \$1.9 million. DRA's proposal was equal to 2005 expenditures, and was based on a statement in PG&E's work papers that capital expenditures in this area would be static.

PG&E responded that the statement regarding a static level of capital expenditures was relative to PG&E's forecast of \$6.65 million of capital spending in 2005 for repaired equipment. Actual spending in 2005 was lower than forecast because funds were shifted to higher priority work, such as new business and emergency response. PG&E states that lower spending on repaired equipment in 2005 does not mean there is less work, only that the work has been deferred.

b. Discussion

The Settlement Agreement provides PG&E with the full amount of its requested revenue requirement for Electric Distribution capital expenditures. Based on our review of the record, we are satisfied that the requested funding is needed to maintain, repair, upgrade, and expand PG&E's Electric Distribution system. We expect PG&E to use all the funds granted by today's Opinion for Electric Distribution capital expenditures for this purpose. If PG&E fails to do, it should provide a detailed explanation in its next GRC.

With this understanding, we find the uncontested Settlement outcome for Electric Distribution capital expenditures to be reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Electric Distribution Plant

PG&E forecasted \$16.810 billion of weighted-average plant in 2007 for Electric Distribution Unbundled Costs Categories (UCCs).⁶⁸ DRA forecasted \$16.754 billion, for a difference of \$54 million. The Settlement adopts \$16.808 billion. Other than the previously described issues concerning capital expenditures, there is no opposition to the Settlement outcome on this matter.

We find the Settlement result for Electric Distribution plant is reasonable in light of the record, consistent with applicable law, and in the public interest.

C. Gas Distribution

1. Gas Distribution Revenues

There were no disputes regarding PG&E's forecasts of gas customers, billings, sales, and 2007 Gas Distribution revenues at present rates. The Settlement Agreement adopts PG&E's forecasts. We concur with this uncontested outcome.

2. Gas Distribution O&M Expenses

PG&E requested \$143 million for Gas Distribution O&M expenses in 2007. DRA and TURN proposed several disallowances. The Settlement adopts \$140 million. The following table compares the Settlement outcome with PG&E's and DRA's litigation positions:

⁶⁸ Electric Distribution UCCs include Wires and Services, Trans-Level Direct Connects, and Electric Public Purpose Program Administration.

Settlement Agreement re: Gas Distribution O&M Expenses (\$ millions)							
	2006 Authorized	Comparison Exhibit		Settlement	Variances Increase/(Decrease)		
		PG&E	DRA		Settlement vs. 2006	PG&E vs. Settlement	DRA vs. Settlement
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
O&M	138.8	142.5	133.0	139.9	1.0	(2.7)	6.9
Source: Settlement Agreement, Appendix B, Line 11.							

Below, we assess the reasonableness of the Settlement outcome for Gas Distribution O&M expenses in light of the record on the issues raised by DRA and TURN.

a. Issues Raised by DRA

DRA recommended that PG&E's requested expenses for Gas Distribution O&M in 2007 be reduced by \$10.156 million. The bulk of DRA's proposed disallowance was in three areas: (1) \$2.402 million for Field Service; (2) \$3.544 million for Building Maintenance; and (3) \$3.670 million for Customer Service Dispatch. These disallowances are addressed elsewhere in today's Opinion where we find the Settlement outcome for these matters is reasonable.⁶⁹

⁶⁹ Field Service is subsumed within our consideration of Gas Field Service and Dispatch Operations expenses. Building Maintenance is subsumed within our consideration of Corporate Real Estate expenses. Customer Service Dispatch is subsumed within our consideration of Customer Services expenses.

b. Issues Raised by TURN

TURN recommends that the Settlement be modified to reduce funding for Gas Distribution O&M expenses in five areas.⁷⁰ We address each area below.

i. Mark and Locate

(A) Position of the Parties

PG&E is required by federal and state law to participate in regional “one-call” notification systems for planned excavation affecting underground utilities.⁷¹ These one-call systems are commonly referred to as “USA,” an acronym for underground service alert. Builders and others planning to excavate must call the USA at least two working days prior to excavating, and PG&E must provide information to the excavators within that two-working day period. PG&E informs the excavators about the location of PG&E’s underground facilities, usually by having PG&E personnel visit the site, locate the underground pipes and wires, and place color-coded surface markings that show where the utilities are located (referred to as “Mark and Locate”). We address here PG&E’s Mark & Locate expenses for both gas and electric distribution.

USA notifications, called “tags,” are transmitted electronically to PG&E and processed by the Utility’s ticket-handling software and mapping personnel. The following table shows USA tag volume since 1992:

⁷⁰ PG&E conceded \$2.798 million (2007\$) of additional disallowances of Gas Distribution O&M expenses recommended by TURN. (TURN comments on the Settlement Agreement, p. 41, Table 1.)

⁷¹ 49 C.F.R. § 192.614 (2005) and Gov. Code § 4216.

<u>Year</u>	<u>USA Tags</u>	<u>% Increase in USA Tags</u>
1992	234,578	
1993	234,390	-0.1
1994	248,759	6.1
1995	263,002	5.7
1996	300,792	14.4
1997	356,371	18.5
1998	394,969	10.8
1999	442,325	12.0
2000	500,109	13.1
2001	508,237	1.6
2002	598,227	17.7
2003	663,325	10.9
2004	711,476	7.3

Source: Exhibit PG&E-4, Chapter 15, Table 1-4

The above Table shows that the number of tags increased by 9.4% annually during 2000 – 2004 and by 11.2% annually during 1995 – 2004. For 2005, PG&E forecasted a 20% decrease in units and an associated 27% increase in unit cost. The reduction in units is due to a change in California law⁷² that increased the life of a USA tag from 14 to 28 days.

Prior to 2005, many tags were extended beyond the 14-calendar day period, which was counted as a new tag. Most of these extensions did not require PG&E to re-mark because the excavator had maintained the marks. The only work associated with these tags was the administrative processing. With the longer valid period, PG&E expects fewer tags, but a higher percentage of tags will require field work, which increases unit cost.

⁷² Gov. Code § 4216. AB 1264.

After 2005, PG&E forecasts that USA tags will increase by 7% annually in 2006 and 2007, which is lower than the historic average, but similar to the 2004 increase. The net result is that PG&E expects to process 651,656 USA tags in 2007 at a total cost of \$31.2 million.

TURN recommends that the Commission modify the Settlement Agreement to reduce Mark and Locate expenses by \$1.201 million in 2007. TURN forecasts lower costs than PG&E because TURN believes the number of USA tags will grow by 4% annually during 2006 and 2007 compared to PG&E's forecast of 7% annual growth. TURN's forecast of lower growth is predicated on a slowdown of residential construction, which is one of the main drivers of PG&E's Mark & Locate expenses.

PG&E responds that its forecast is better than TURN's for five reasons: (1) TURN's proposed tag growth of 4% annually is less than historical growth; (2) PG&E's forecasted tag growth of 7% annually is conservative, as it is less than historical growth; (3) TURN's proposed growth rate is based on a small snapshot in time, the first few months of 2006, which were an exceptionally rainy period making construction difficult; (4) PG&E's 2005 actual costs were 1.5% higher than PG&E's 2005 forecast in A.05-12-002; and (5) there will likely be an increase in tags because of proposed changes in California law designed to improve safety for excavators.

(B) Discussion

TURN forecasts 4% annual growth of USA tags during 2006 and 2007. PG&E forecasts 7% annual growth. PG&E acknowledges that residential

construction is a significant driver of Mark & Locate expenses.⁷³ Official data shows that residential construction in California declined by 1.9% in 2005, the first decline since 1996.⁷⁴ Recent economic data show that the downturn in residential construction accelerated in 2006. In the first eight months of 2006 the pace of homebuilding in California was down nearly 16% from the same period in 2005.⁷⁵ Based on this data, we conclude that TURN's forecast of 4% annual growth in USA tags during 2006 and 2007 is more plausible than PG&E's forecast of 7% annual growth, and that TURN's forecast may actually be overly generous.

The information available for 2006 does not support PG&E's forecast of 7% annual tag growth in 2006 and 2007. During the first four months of 2006 there were 9% fewer tags than the comparable period for 2005.⁷⁶ PG&E submits that above-normal rain accounts for the reduced tags in 2006. It is true that the number of rain days during January-April 2006 was 27% higher than 2005.⁷⁷ However, TURN provided information which indicates that rain cannot account for this entire decrease in tags. PG&E's calculation of a 27% increase in rain days was based on the average of six weather stations over four months. TURN's review of the data shows that weather was drier at every weather station during February 2006 as compared to February 2005, with a total of 24 fewer rain days. Despite the drier weather, tags declined in February 2006 by 1.7% relative to

⁷³ Exhibit PG&E-18, p. 23-7, Line 31.

⁷⁴ TURN comments filed on September 20, 2006, p. 44.

⁷⁵ California Department of Finance October 2006 monthly economic update. (http://www.dof.ca.gov/HTML/FINBULL/2006_FB/October/Oct06.asp) We take official notice of this economic data pursuant to Rule 13.9.

⁷⁶ Exhibit TURN-15.

⁷⁷ Exhibit TURN-15.

February 2005.⁷⁸ This information demonstrates that it is unlikely that rain accounts for the entire decrease in tags during the first four months of 2006. A more reasonable explanation is that the significant decrease in residential construction was a major factor in the reduction of tags.

PG&E contends that its forecast of 7% annual growth in tags in 2006 and 2007 is reasonable because there will likely be an increase in tags during the GRC cycle due to proposed changes in California state law. PG&E testified that Cal/OSHA and Senator Tolakson are working to introduce legislation that will improve safety for excavators by requiring more excavators to call to have underground facilities located and marked prior to excavating.⁷⁹

PG&E's anticipation of new legislation is not a reasonable basis for finding that PG&E will have 7% annual growth in tags during 2006 and 2007. We conclude for the preceding reasons that TURN's forecast of 4% annual growth of tags during this period is reasonable and may even be too high.

The Settling Parties maintain that TURN's proposed disallowance of \$1.201 million is reflected in the Settlement outcome for Gas Distribution O&M expenses. The Settlement provides \$140 million for Gas Distribution O&M expense in 2007, which is \$3 million less than PG&E's request of \$143 million and \$7 million more than DRA's recommendation.

Almost all of the difference between PG&E and DRA was in three areas: (1) DRA's proposed disallowance of \$2.4 million for gas service representative staff levels; (2) DRA's proposed disallowance of \$3.7 million for a software upgrade to PG&E's Field Automation System (FAS); and (3) DRA's proposed

⁷⁸ TURN comments dated September 20, 2006, pp. 43-44.

⁷⁹ Exhibit PG&E-18, p. 23-8.

disallowance of \$3.5 million for several PG&E's projects to rehabilitate and renovate real estate facilities.⁸⁰ After reviewing the record on these issues, we find the Settlement outcome of providing PG&E with \$3 million less than it requested is reasonably close to how we would have decided the three disallowances proposed by DRA and all of TURN's proposed disallowances for Gas Distribution O&M expenses, including TURN's proposed reduction of \$1.201 million for Mark & Locate.⁸¹ We address TURN's other proposed disallowances of Gas Distribution O&M expenses below.

For the preceding reasons, we conclude that the Settlement outcome for Mark & Locate expenses is reasonable in light of the whole record, consistent with applicable law, and in the public interest. Therefore, we decline to adopt TURN's proposal to modify the Settlement Agreement on this matter.

ii. Leak Survey

(A) Position of the Parties

PG&E requested \$6.271 million for Leak Survey expenses in 2007. DRA did not contest PG&E's request. TURN recommends a disallowance of \$0.157 million. The reason for the difference between PG&E's and TURN's positions is that TURN proposes a 9% increase in Leak Survey expenses in 2007 compared to 2004, which is less than PG&E's requested 12% increase. TURN's escalation rate is based on recorded costs for 2000-2005, while PG&E's escalation rate is based on the 10-year average growth rate of 1.3% in the number of miles

⁸⁰ PG&E email to service list on November 22, 2006.

⁸¹ For example, it is likely that we would have granted PG&E's full requests for (i) FAS software upgrade, and (ii) building seismic retrofits and upgrades.

surveyed. TURN believes its approach is superior because PG&E's Leak Survey costs were mostly declining during 2000-2005.

PG&E responds that TURN's ignores the main driver of the long-term growth in these expenses, namely, the growth in PG&E's gas distribution system.

(B) Discussion

We find TURN's forecast for Leak Survey expenses in 2007 to be markedly better than PG&E's. As noted by TURN, PG&E's forecast of \$6.271 million is out of line with its actual expenses during 2000-2005, which were as follows:

PG&E Leak Survey Expenses (\$millions)							
2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Forecast	2007 Forecast
5.965	5.848	5.665	6.033	5.610	5.651	6.075	6.271
Source: Exhibits TURN-13 and TURN-14							

PG&E's forecast of \$6.271 million for Leak Survey expenses is 11% higher than 2005. We agree with TURN's observation that PG&E's forecasted increase is excessive in light of PG&E's generally flat to declining expenses during 2000-2005. TURN's proposed increase of 9% for Leak Survey expenses in 2007 compared to 2004 (which exceeded 2005) is reasonable, if not generous.

Although we agree with the general merits of TURN's position, we decline to modify the Settlement Agreement to reduce funding for Leak Survey expenses in 2007 by \$0.157 million. The Settlement provides \$140 million for Gas Distribution O&M expense in 2007, which is \$3 million less than PG&E requested. The Settling Parties represent that the Settlement outcome takes into consideration TURN's position on Leak Survey expenses. We conclude that because TURN's proposed disallowance of \$0.157 million for Leak Survey

expenses is small compared to the Settlement Agreement's reduction of \$3 million for Gas Distribution expenses, it is reasonable to assume that TURN's disallowance is reflected in the Settlement. Based on this assumption, we find the Settlement outcome for Leak Survey expenses is reasonable in light of the whole record, consistent with the law, and in the public interest.

iii. Operate Gas Systems

(A) Position of the Parties

PG&E's Operate Gas System (OGS) activities include (1) monitoring system pressures, flows, odorant levels, (2) operating valves and regulator stations, and (3) adjusting gas flow rates in response to demand. PG&E requested \$3.3 million expenses for OGS in 2007.

TURN recommends a disallowance of \$0.135 million in 2007 because OGS costs generally declined during 2000-2005. PG&E responds that TURN's proposal ignores inflation and system growth. PG&E also contends that its efforts to drive down costs in 2000-2004 should not be used to deny recovery of future cost increases that are driven by inflation and system growth.

(B) Discussion

We generally agree with TURN that PG&E's forecast of OGS costs in 2007 is too high in relation to its recorded costs. PG&E's recorded and forecast costs for OGS are as follows:

(\$000)						
2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2007 Forecast
2,566	2,764	3,143	2,888	2,666	2,680	3,257
Source: Exhibit TURN-16						

We are not persuaded by PG&E that OGS costs will be 21.5% higher in 2007 compared to 2005. Likewise, we are not convinced by PG&E's argument that its successful efforts to constrain OGS costs during 2000-2005 cannot be continued in 2007.

Although we agree with the general merits of TURN's position, we decline to adopt its proposal to modify the Settlement Agreement to reduce OGS expenses in 2007 by \$0.135 million. The Settling Parties agree that the revenue requirement for OGS is subsumed within the Settlement outcome for Gas Distribution O&M expenses. The Settlement provides \$140 million for gas distribution operations expense in 2007, which is \$3 million less than PG&E's request of \$143 million. The Settling Parties further agree that the Settlement outcome takes into consideration TURN's position on OGS expenses. We conclude that because TURN's proposed adjustment of \$0.135 million for OGS is small in relation to the Settlement Agreement's overall reduction of \$3 million for gas distribution expenses, it is reasonable to assume that TURN's proposed adjustment is reflected in the Settlement Agreement. Based on this assumption, we find that the Settlement outcome for OGS expenses is reasonable in light of the whole record, consistent with the law, and in the public interest.

iv. Corrective Maintenance

(A) Position of the Parties

Corrective maintenance consists of repairing and replacing damaged or failed facilities. PG&E requested \$19.266 million for corrective maintenance expenses in 2007.

TURN proposes that funding for corrective maintenance be reduced by \$0.539 million based on historical costs during 2000-2005. TURN contends that its reduction is reasonable in light of lower unit costs in 2005.

PG&E responds that its forecast of 2007 expenses, which was based on 2004 recorded costs inflated by the ten-year average increase of 1.3%, is reasonable because (1) it is only 5% higher than 2004 recorded costs; (2) TURN's estimate ignores circumstances that drove down PG&E's unit costs in 2005, and which will not recur 2007; and (3) the 2005 data used by TURN does not reflect the fluctuating nature of corrective maintenance costs.

(B) Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to reduce funding for corrective maintenance by \$0.539 million. PG&E's recorded and forecasted costs for corrective maintenance are as follows:

(\$000)							
2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2006 Forecast	2007 Forecast
20,505	20,900	19,883	17,912	18,312	18,288	18,715	19,266
Source: Exhibit TURN-17							

PG&E's forecast of 2007 expenses is based on 2004 recorded costs inflated by the ten-year average annual increase of 1.3%. The result is that 2007 forecasted costs are 5.2% higher than 2004 recorded costs, and less than recorded costs in 2000, 2001, and 2002. We conclude that this outcome is reasonable.

TURN argues that we should reduce PG&E's requested expenses in 2007 because PG&E forecasts that unit costs will be higher in 2007 compared to 2005. While there is some merit to TURN's position, other historical measures of costs discussed in the previous paragraph demonstrate that PG&E's forecast for 2007 is reasonable.

v. Meter Protection Program

(A) Position of the Parties

The purpose of PG&E's Meter Protection Program (MPP) is to correct gas meter installations that do not conform to Federal safety regulations. The program encompasses approximately 400,000 meter locations that are to be inspected and modified, as necessary, between 1990 and 2016. At the end of 2004, PG&E had inspected all 400,000 locations, found that approximately 107,000 meters required corrective action, had corrected approximately 66,000 meters, and had roughly 41,000 meters awaiting corrective action.

PG&E requested \$3.246 million for MPP expenses in 2007. PG&E's request was based on the remaining scope of the program, the program schedule, and unit costs. TURN recommends that the Commission modify the Settlement Agreement to reduce funding for the MPP in 2007 by \$0.359 million. TURN's proposal is based on the three-year average of expenses in 2003-2005 escalated by 5% to reflect more expensive work.

PG&E responds that unit costs in 2007 will exceed the historical average recommended by TURN because of (1) labor and material escalation, and (2) changes in the scope of work. In 2004, approximately 30% of the locations with inaccessible service valves were resolved by raising valve boxes instead of installing new valves. PG&E anticipates higher unit costs in 2007 and beyond as the easy-to-fix locations are depleted.

PG&E contends that TURN's use of a three-year average is flawed for several reasons. First, the MPP is driven by Department of Transportation and California Fire Code requirements. In order to achieve the goals of the program on schedule, PG&E must adhere to the forecasts in its testimony. Second, PG&E has finalized the scope of this program, resulting in a more accurate forecast.

Finally, over the three-year period used by TURN (2003-2005), PG&E's expenditures exceeded its 2003 GRC forecast by 8%, demonstrating PG&E's commitment to finishing this program on schedule in 2016.

(B) Discussion

We decline to adopt TURN's proposal to reduce funding for the MPP by \$0.359 million. The MPP is a vital public safety program, and we want to ensure that it is fully funded. Given the importance of the MPP to public safety, we expect PG&E to utilize all of the \$3.246 million of annual funding provided by today's Opinion for the MPP for that purpose only. If PG&E fails to do, it should provide a detailed explanation in its next GRC.

c. Conclusion

Based on our review of the record, we conclude for the preceding reasons that the Settlement outcome for Gas Distribution O&M expenses is reasonable in light of the record, consistent with applicable law, and in the public interest.

3. Gas Distribution Capital Expenditures

PG&E requested \$205.0 million for Gas Distribution capital expenditures in 2007. DRA recommended \$193.9 million, for a difference of \$11.1 million. No other parties addressed this matter. The following table compares PG&E's and DRA's litigation positions on Gas Distribution capital expenditures:

2007 GRC Comparison Gas Distribution Capital Expenditures by Functional Groups (\$000)				
	2007 Capital Expenditures			
Description	PG&E	DRA	PG&E > DRA	% Difference
Gas Pipeline Replacement Program	68,353	59,562	8,791	12.9%
Gas Meter Protection-Capital	695	695	0	0.0%
Gas Dist. Customer Connects	59,783	59,783	0	0.0%
Gas Dist. New Capacity – Gas	11,182	11,182	0	0.0%
Gas Dist. Reliability	15,767	13,423	2,344	14.9%
Gas Dist. Work Requested by Other	18,093	18,093	0	0.0%
Gas Dist. Emergency Response	203	203	0	0.0%
Gas Meters	30,918	30,918	0	0.0%
Total	204,995	193,860	11,135	5.7%
Source: Exhibit PG&E-79, p. D-2				

The Settlement Agreement adopts PG&E’s requested Gas Distribution capital expenditures of \$205.6 million.⁸²

Below, we assess the reasonableness of the Settlement outcome for Gas Distribution capital expenditures in light of the record on the issues raised by DRA.

a. Summary of the Record

i. Gas Pipeline Replacement Program

PG&E requested \$66.953 million in 2007 for Gas Pipeline Replacement Program (GPRP) capital expenditures. DRA recommended \$59.562 million, for a

⁸² The Settlement Agreement inadvertently incorporates PG&E’s requested capital expenditures of \$31.542 million for gas meters in 2007 when the Settling Parties agreed to DRA’s recommended amount of \$30.918 million. We will reflect the lower DRA amount in the revenue requirement and rate base adopted by today’s Opinion.

difference of \$7.391 million. Subsequently, PG&E and the Disability Rights Advocates agreed to a Memorandum of Understanding (MOU), which increased PG&E's 2007 request for the GPRP by \$1.4 million to \$68.353 million. There is no opposition to the MOU, which is addressed elsewhere in today's Opinion.

PG&E's request for GPRP capital expenditures in 2007 was based on the remaining scope of the program, PG&E's schedule commitment to the Commission, and pipe replacement costs. PG&E contended that its requested funding would allow PG&E to complete the remaining 250 miles of the highest risk pipe in PG&E's system by 2009 for all areas outside of San Francisco, and by 2014 for San Francisco. DRA's forecast for 2007 was based on the inflation-adjusted average of recorded expenditures during 2003-2005 and the ratio of historical budgeted expenditures to actual expenditures.

ii. Gas Reliability

PG&E requested \$15.767 million in 2007 for capital expenditures to maintain and enhance the reliability of its Gas Distribution infrastructure. DRA recommended \$13.423 million, for a difference of \$2.344 million. PG&E's request was based on historical expenditures and known future projects. DRA used a 4-year, inflation-adjusted average to determine its 2007 forecast.

b. Discussion

The Settlement Agreement provides PG&E with the full amount of its requested capital expenditures for Gas Distribution. The bulk of the difference between PG&E's request and DRA's proposal pertains to GPRP, where PG&E requested, and the Settlement adopts, \$7.391 million more than DRA recommended. The amount provided by the Settlement for GPRP capital spending is well above the historical four-year average adjusted for inflation.

The GPRP is a high-priority program that affects public safety and the reliability of PG&E's Gas Distribution system. We conclude that it is reasonable for the Settlement to provide substantially increased funding for this program, provided that PG&E actually spends these funds on the GPRP.⁸³ Therefore, we will approve the Settlement outcome for Gas Distribution capital expenditures with the condition that PG&E uses all the funds provided by the Settlement for the GPRP for this purpose. If PG&E fails to do, it should provide a detailed explanation in its next GRC. Absent a compelling explanation, we may impose a disallowance similar to the deferred-maintenance disallowance addressed elsewhere in today's Opinion.

With this condition, we find the Settlement outcome for Gas Distribution capital expenditures to be reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Gas Distribution Plant

PG&E forecasted \$6.049 billion of weighted-average plant-in-service in 2007 for Gas Distribution UCCs.⁸⁴ DRA proposed \$6.028 billion, for a difference of \$21 million. The Settling Parties agree to \$6.048 billion, effectively adopting PG&E's forecast. There is no opposition to the Settlement on this matter.

We find that the uncontested Settlement outcome for Gas Distribution plant-in-service is reasonable in light of the whole record, consistent with applicable law, and in the public interest.

⁸³ PG&E's actual expenditures for the GPRP have sometimes fallen short of budgeted expenditures. (Exhibit DRA 15, p. 15-5, Table 15-3.)

⁸⁴ Gas Distribution (GD) UCCs include GD Pipes and Services, GD Gas Procurement Administration, and GD Gas Public Purpose Program Administration.

D. Electric Generation

1. Generation Revenues

There were no disputes regarding PG&E's forecasts of Electric Generation billings, sales, and 2007 revenues at present rates. The Settlement Agreement adopts PG&E's forecasts. We concur with this uncontested outcome.

2. Generation O&M Expenses

PG&E requested \$457 million in 2007 for Generation O&M expenses. DRA recommended \$406 million, for a difference of \$51 million. The Settlement adopts \$451 million, which is \$6 million less than PG&E requested and \$45 million more than DRA recommended.

a. Hydro Operations

PG&E has 68 hydro powerhouses located on 16 rivers and four tributaries of the Sierra Nevada, Cascade, and Coastal mountain ranges. The generating capacity of PG&E's Hydro system is 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 128 miles of canals and flumes, 135 miles of tunnels, 19 miles of pipe, 5 miles of natural waterways, and approximately 140,000 acres of fee-owned land. The Hydro system operates under 26 FERC licenses, 92 water right licenses, and 160 Statements of Water Diversion and Use.

PG&E requested \$143.9 million for Hydro O&M expenses in 2007, an increase of 42.3% over 2004 recorded expenses. PG&E's request was based on actual 2004 expenses, approved budgets for 2005, recommended budgets for 2006, and long-term plans for 2007. PG&E testified that the increased expenses in 2007 are due to higher maintenance costs for aging Hydro assets and significantly higher regulatory compliance costs for new FERC licenses, new environmental and safety regulations, and increased regulatory fees.

DRA recommended \$108.6 million for Hydro O&M expenses in 2007, or \$35.3 million less than PG&E requested. Aglet and TURN proposed disallowances of \$32.1 million and \$7.91 million, respectively.

The Settling Parties agree that the resolution of all issues regarding PG&E's revenue requirement for Hydro O&M expenses is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides \$450.6 million for Generation O&M expenses in 2007, which is \$6.4 million less than PG&E requested.

Below, we assess the reasonableness of Settlement outcome for Hydro O&M expenses in light of the record on the issues raised by the parties.

i. Issues Raised by DRA

DRA recommended \$108.6 million for Hydro O&M expenses in 2007, or \$35.3 million less than PG&E requested. DRA's recommendation was based on the three-year average of Hydro O&M expenses during 2003 - 2005.

PG&E responded that DRA's reliance on historical information was inappropriate because it failed to capture significantly higher regulatory compliance costs associated with new FERC license conditions, new environmental and safety regulations, and regulatory fees.

Based on our review of the record, we find that PG&E has demonstrated that its Hydro O&M expenses will be significantly higher in 2007 compared to historical levels, primarily because of costly new conditions that are now being routinely attached to new and amended hydro licenses issued by FERC.

Therefore, we conclude that the Settlement outcome for Hydro O&M expenses is reasonable in light of the record on the issues raised by DRA.

ii. Issues Raised by Aglet and TURN

(A) Forecasted Hydro O&M Expenses for 2007

(1) Position of the Parties

Aglet recommends \$111.9 million for Hydro O&M expenses in 2007, or \$32.1 million less than PG&E requested. Aglet's recommendation is based on a linear trend of recorded and budgeted costs from 1998 through 2006, extrapolated to 2007. Aglet believes that reliance on historical data to forecast Hydro O&M costs in 2007 is reasonable because (1) there is no new Hydro plant that requires additional O&M expenses, (2) the observed trend of slowly increasing costs should cover increased operational needs, and (3) PG&E's requested Hydro O&M expenses are simply too far above historical levels. Aglet also identified the following "soft spots" in PG&E's work papers:

- FERC issued a new license for Rock Creek-Cresta in 2001, but implementation expenses jump from zero to \$698,000 in 2006.
- The costs for several projects rise dramatically, but FERC has not yet issued new licenses or licenses amendments for these projects, and the license conditions are uncertain.
- Bucks Creek Article 103 implementation costs spike in 2007, but the timing of such costs is uncertain.
- Costs at Helms for venting transformer cases and installing blast walls look more like capital projects than expenses.
- Hiring and training costs are relatively flat during 2005 - 2009, but the number of new hires declines from 13 in 2005 to 3 in 2008.
- Canal system improvements and flume repair costs rise from zero in 2006 to more than \$4 million in 2009, but repair needs for waterways that are 50 to 100 years old should be stable.
- Dam repair costs rise from zero in 2006 to more than \$3.3 million in 2009, but the listed activities are illustrative only.

- Lead paint and PCB monitoring and abatement costs rise from zero in 2005 to \$1 million in 2009, but PG&E has not shown any rise in associated hazards.
- Miscellaneous safety costs rise by a factor of seven beginning in 2007, but PG&E has not shown any rise in safety risks.

Aglet states that the above projects have some justification, but they look like a wish list. All told, Aglet finds that PG&E has not shown with clear and convincing evidence that a large increase in Hydro O&M expenses is necessary.

PG&E responds that Aglet's use of historical data to forecast Hydro O&M expenses fails to capture significantly higher regulatory, environmental, and safety compliance expenses. For example, compliance costs grew by 73% between 2003 and 2006. This was due primarily to the greatly expanded scope of FERC license conditions for six new licenses received between 2001 and 2003. PG&E's forecasted increase in 2007 assumes there will be a similar increase in compliance costs for five new licenses and two major license amendments that PG&E expects to receive by then.

Although some licenses have been delayed since PG&E filed A.05-12-002, thereby deferring some expenses, PG&E testified that it will incur costs for two projects in 2007 that were not included in its forecast of 2007 O&M expenses -- one project to clear and repair rock movement at the Belden project, and second project for a seismic upgrade of the Crane Valley Dam.

(2) Discussion

Aglet proposes to use historical data to forecast Hydro O&M expenses in 2007 rather than PG&E's project-based forecast. We find PG&E's approach to be superior to Aglet's. PG&E testified that all of the forecasted projects are cost effective and/or required for legal, safety, or other reasons. Aglet did not attempt to show with substantive evidence that any particular project is not

necessary, cost effective, or beneficial. PG&E's forecast also reflects the dramatic increases in regulatory, environmental, and safety compliance costs in recent years, and PG&E testified that such costs will continue to increase as PG&E receives new and amended FERC licenses.⁸⁵ In contrast, Aglet relies on historical data that does not capture the significant increases in compliance costs that PG&E has testified will drive Hydro O&M expenses in 2007.

For the preceding reasons, we find that PG&E has demonstrated with clear and convincing evidence that the Settlement outcome for Hydro O&M expenses in 2007 with respect to the issues raised by Aglet is reasonable in light of the record. Accordingly, we decline to adopt Aglet's proposal to reduce funding for Hydro O&M expenses.

(B) Delayed Projects

(1) Position of the Parties

TURN proposes that the Commission modify the Settlement Agreement to reduce Hydro O&M expenses in 2007 by \$1.94 million for delayed projects. The basis for TURN's proposal is a PG&E data response wherein PG&E admits that some of the regulatory compliance costs it forecast for 2007 may be deferred because of delays in the issuance of new FERC licenses and license amendments.

PG&E acknowledges that some regulatory compliance costs may be deferred because of the delays identified by TURN. PG&E contends, however, that the deferred costs will be offset by expenses for two unforeseen projects -- one project to clear and repair rock movement at the Belden project, and second project for a seismic upgrade of the Crane Valley Dam

⁸⁵ Exhibit PG&E-3, pp. 3-24 to 3-35.

TURN urges the Commission to reject PG&E's argument that the reduction of regulatory compliance costs in 2007 is offset by two new projects that were not included in PG&E's forecast. TURN argues that the cost and timing of the unforeseen projects is vague and, therefore, should not be used as justification for allowing recovery of \$1.94 million of deferred regulatory compliance costs.

(2) Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to remove \$1.94 million for projects that have been postponed because of delays in the issuance of new FERC licenses and license amendments. PG&E will clearly incur these costs, it is only a question of when. We conclude that because PG&E's license applications have been pending at FERC for some time,⁸⁶ it is likely that FERC will issue the new licenses and license amendments sometime during the GRC cycle. Adopting TURN's proposal would effectively deny PG&E the ability to recover some or all of the regulatory compliance costs for these new licenses and amendments. Such a result would be unfair to PG&E and contrary to the public interest, since there is no question that these costs are reasonable and necessary.

Although there will be some reduction in PG&E's regulatory compliance costs in 2007 because of the delay in the issuance of new and amended licenses, we are persuaded that the reduction in costs will be more than offset by other costs that PG&E will incur in 2007 and subsequent years for two unforeseen projects.⁸⁷ These projects are (1) \$10 million for safety-related work to address

⁸⁶ Exhibit PG&E-3, p. 3-24, L:20-23.

⁸⁷ The Settlement Agreement provides PG&E with less money than it requested for Generation O&M expenses. The time-value-of-money savings that accrue from the

Footnote continued on next page.

rock movement at the Belden project, and (2) \$5-7 million for a seismic upgrade of the Crane Valley Dam.⁸⁸ PG&E will have to absorb the associated costs under the revenue requirement provided by the Settlement Agreement.

This is an important point for test-year ratemaking and the Commission's consideration of the Settlement. PG&E prepared its forecast of costs in 2007 with the information that was available to PG&E in 2005. Actual costs in 2007 and subsequent years of the GRC cycle will likely be higher and lower across the range of cost categories. The central issue is whether the Settlement Agreement contains a reasonable forecast of PG&E's regulatory compliance costs in 2007 and subsequent years. We find that it does for the preceding reasons.

(C) Regulatory Fees

(1) Position of the Parties

TURN raised two issues regarding Hydro-related regulatory fees. The first issue concerns PG&E's request for \$5.13 million of "other regulatory fees" (OR fees) in 2007. TURN opposes PG&E's request.

PG&E's requested OR fees consist of two components. The first is \$2 million for fees levied pursuant to the Endangered Species Act (ESA) for habitat restoration at the Upper North Fork Feather River (UNFFR) project. TURN states that the project has been postponed and that PG&E has admitted that the forecast of \$2 million is speculative. TURN argues that PG&E has not demonstrated with convincing evidence that it will incur ESA fees in 2007.

deferral of \$1.94 million of Regulatory Compliance costs is captured, at least to some degree, in the Settlement's reduction of Generation O&M expenses.

⁸⁸ 13 RT 1001:1-28, PG&E/Sweeney.

The second component is \$3.2 million that PG&E estimates it will pay to CALFED in 2007 to finance the Bay-Delta Program Ecosystem Restoration Program. TURN states that PG&E's forecast is based on (1) a draft report issued by CALFED in 2005, and (2) one of three possible methods identified in the draft report for calculating the fee. TURN asserts that PG&E does not know when CALFED will finalize the method for calculating the fee or begin collecting the fee. This demonstrates, according to TURN, that there is no basis whatsoever for allowing PG&E to recover CALFED fees.

The second issued raised by TURN regarding regulatory fees pertains to PG&E's request for \$2.757 million in 2007 for FERC Other Federal Agency (OFA) fees. TURN provided a PG&E data response wherein PG&E admitted that OFA fees are an "estimated liability" that might never be paid to the government:

Since 2003 FERC has not required licensees to actually pay the annual OFA fees. FERC provided each licensee with an estimated OFA fee liability for each licensed project in 2003. FERC has not indicated conclusively what the final OFA fee liability might be for 2003 or subsequent years. FERC may also decide to charge licensees for prior year OFA fees that it partially refunded. PG&E has continued to accrue an estimated liability amount to cover potential OFA fee charges. (Exhibit TURN-24.)

TURN recommends that the Commission either (1) adopt balancing account treatment for OFA fees, or (2) modify the Settlement to eliminate the entire \$2.757 million that PG&E requested for OFA fees in 2007.

PG&E responds that it expects to incur all of the forecasted regulatory fees in 2007. PG&E argues that although its forecast might be imperfect, that does not make its forecast unreasonable.

(2) Discussion

We are persuaded that it is more likely than not that PG&E will incur some level of OR Fees and OFA fees at some point during the GRC cycle. Therefore, we decline to adopt TURN's proposal to remove all funding for these fees from the Settlement Agreement.

We are also persuaded by TURN that PG&E's forecast of OR fees and OFA fees is subject to considerable uncertainty. For example, the OFA fees have not been paid since 2003, and TURN demonstrated through cross examination of PG&E's witness that PG&E does not know if it will pay all the fees as estimated, only a portion of the fees, or no fees at all.⁸⁹

Even though there is some uncertainty surrounding the amount of regulatory fees that PG&E will ultimately pay, we will not adopt TURN's proposed balancing account for OFA fees. Instead, in its next GRC, PG&E shall report on the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and provide a forecast of future OR and OFA costs based on its actual payment history.

(D) Deferred Maintenance

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement Agreement to exclude \$0.791 million for lead paint and PCB abatement expenses. PG&E requested and received funding for these expenses in its 2003 GRC, and now requests funding a second time for lead paint and PCB abatement.

⁸⁹ 13 RT 998, 22-26, Sweeney, PG&E.

TURN calls PG&E's request a classic example of deferred maintenance. It arises when a utility seeks money for a specific maintenance activity, does not perform the maintenance, and then seeks money again for the same maintenance activity, thereby requesting to be paid twice. TURN opines that excluding deferred maintenance from rates is vital to the integrity of test-year ratemaking.

TURN cites several Commission decisions that denied ratepayer funding for deferred maintenance. For example, in D.00-02-046 the Commission held:

It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. (D.00-02-046, Conclusion of Law 15, *mimeo.*, p. 536.)

More recently, the Commission disallowed \$1.4 million in annual expenses and \$3.4 million in capital costs that SCE requested for deferred pole maintenance, stating that "ratepayers should not be required to pay twice for the same authorized expense."⁹⁰

PG&E responds that it will not be paid twice. This is because PG&E's actual expenditures for environmental remediation work exceeded the 2003 GRC forecast. As shown in the following table, increased costs for other remediation work more than offset the under-run for lead paint and PCB abatement.

⁹⁰ D.04-07-044, *mimeo.*, pp. 105, 108-110.

(Millions of Dollars)				
<u>Lead Paint and PCB Abatement</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Total</u>
2003 GRC Forecast	1.6	1.6	1.3	4.5
Actual	0.8	0.6	0.7	2.1
Under Spent	0.8	1.0	0.6	2.4
<u>Environmental Compliance</u>				
2003 GRC Forecast	8.8	11.2	10.0	30.0
Actual	9.6	12.3	11.4	33.3
Over Spent	(0.8)	(1.1)	(1.4)	(3.3)
Total Over Spent	0.0	(0.1)	(0.8)	(0.9)

PG&E argues that under TURN's reasoning, PG&E would have no discretion to reschedule work to reflect changing priorities. This reasoning would require that all work be performed as estimated or PG&E would never be allowed to recover the cost of the work.

(2) Discussion

The Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past.⁹¹ Here, there is no dispute that PG&E received funding for lead paint and PCB abatement in its prior GRC proceeding, and that PG&E seeks funding for these activities a second time in the current proceeding.

The Settlement Parties state that the issue of funding for lead paint and PCB abatement is subsumed in the Settlement outcome for Generation O&M

⁹¹ D.04-07-044, *mimeo.*, pp. 105, 108-110; D.00-02-046, COL 15.

expenses.⁹² The Settlement provides \$450.6 million for Generation O&M expenses in 2007, which is \$6.4 million less than PG&E requested.

In order to find that the Settlement Agreement is consistent with the law, which includes adherence to long-established Commission precedent, we must be satisfied that all of PG&E's lead paint and PCB abatement costs are excluded from the O&M expenses adopted by the Settlement. We conclude that the \$6.4 million reduction to O&M expenses adopted by the Settlement is sufficiently large to accommodate a 100% disallowance of \$0.791 million for lead paint and PCB abatement. Based on this conclusion, we find that the Settlement outcome is reasonable in light of the record, consistent with long-established Commission precedent, and in the public interest.

b. Nuclear Operations

PG&E's Diablo Canyon nuclear power plant has two generation units with a combined capacity of 2,200 megawatts (MW). PG&E requested \$310.8 million for Nuclear O&M expenses in 2007. DRA recommended \$295.6 million, which was \$15.2 million less than PG&E requested. Aglet, TURN, and ANR/SC proposed additional disallowances.

The Settling Parties agree that the resolution of issues regarding Nuclear O&M costs is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides \$450.6 million for Generation O&M expenses in 2007, which is \$6.4 million less than PG&E requested.

⁹² Settlement Motion, p. 87.

Below, we assess the reasonableness of the Settlement outcome for Nuclear O&M expenses in light of the record for the issues raised by DRA, Aglet, TURN, and ANR/SC.

i. Issues Raised by the Parties

(A) New Information System and Pump

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement to reduce PG&E's Nuclear O&M expenses in 2007 by \$1.2 million to reflect projected O&M savings from PG&E's planned capital expenditures for a new Plant Management Information System (PIMS) and a new, more efficient pump. Otherwise, ratepayers will fund the capital expenditures but receive none of the benefits.

PG&E responds that the O&M expense savings were reflected in its GRC application in the form of avoided costs (i.e., costs that would not be incurred and, therefore, not requested).

(2) Discussion

We find that PG&E has affirmatively demonstrated through clear and convincing evidence that the O&M expense savings from PIMs and the new pump are reflected in PG&E's application (and the Settlement Agreement) in the form of avoided costs.⁹³ Therefore, we decline to adopt TURN's recommendation.

(B) License Renewal Feasibility Study

Diablo Canyon operates pursuant to two licenses issued by the NRC that expire in 2024 (Unit 1) and 2025 (Unit 2). PG&E's request for Nuclear O&M

⁹³ 29 RT 2751:20-21, PG&E/Becker. See also Exhibit TURN-62.

expenses included \$16.8 million spread over 2007-2009 for a license renewal feasibility study. The purpose of the study is to analyze Diablo Canyon equipment and operations to determine whether to apply to the NRC for a 20-year extension of the two Diablo Canyon licenses.

DRA opposed funding for the license renewal feasibility study on the grounds that it is premature. ANR/SC and TURN opposed the feasibility study for the same reason and others. The Settling Parties agree that funding for the study is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides \$450.6 million for Generation O&M expenses in 2007, which is \$6.4 million less than PG&E requested and \$44.3 million more than DRA recommended.⁹⁴

(1) Position of the Parties

ANR/SC and TURN recommend that the Commission modify the Settlement Agreement to remove \$16.8 million for the Diablo Canyon license renewal feasibility study. TURN alternatively proposes that the \$16.8 million be deferred as a regulatory asset that (1) accrues interest at the rate that applies to the allowance for funds used during construction (AFUDC), and (2) is amortized over the life of the renewed licenses beginning in 2024.

ANR/SC and TURN contend that it is premature to fund a study that will be completed in 2009, which is 15 years before the first NRC license expires in 2024. They believe that a study completed in 2009 will be irrelevant to circumstances in 2024. As such, the study will be a waste of ratepayers' money.

⁹⁴ Settlement, para. 17 and Appendix G, L. 19.

ANR/SC and TURN provide several examples of PG&E's record of vastly underestimating the future cost of operating Diablo Canyon and overestimating the service life of major power plant components and systems. Given this poor track record, they believe the Commission and the public can have little confidence that PG&E's license renewal study will be of any value in deciding whether to renew the licenses 15 years after the study is completed.

Another reason ANR/SC and TURN believe the study is premature is the recent enactment of Assembly Bill (AB) 1632.⁹⁵ This statute requires the California Energy Commission (CEC) to review the potential impacts of aging, seismic events, and nuclear waste accumulation at existing nuclear power plants.⁹⁶ ANR/SC and TURN believe the CEC's review, which is scheduled to be completed in 2008, will shape the State's policy on nuclear re-licensing. ANR/SC and TURN contend there is no point in ratepayers funding PG&E's study prior to the completion the CEC's study.

ANR/SC and TURN are particularly concerned that PG&E may use the license renewal study to unilaterally seek license renewal without prior Commission review of the study or Commission authority for PG&E to submit a re-licensing application. They state that there are many factors that must be considered before deciding whether to proceed with re-licensing. These factors include the ongoing accumulation of high-level nuclear waste at Diablo Canyon, the ever rising cost of nuclear power, and the Commission's evolving energy procurement policies.

⁹⁵ Statutes of 2006, Chapter 722.

⁹⁶ PRC § 25303(a)(8), (c).

PG&E responds that it is prudent to perform the license renewal feasibility study at this time in order to develop the factual and regulatory information needed to decide whether to apply for license renewal. The scope of the study would include (1) screening Diablo Canyon's structures, systems, and components to determine if they are within the scope of a renewed license; (2) performing an aging analysis of the in-scope systems and components to determine the need for additional monitoring programs; and (3) preparing a draft environmental impact report.

PG&E offers several other reasons why it is appropriate to conduct the license renewal feasibility study at this time. First, PG&E's witness testified that:

[t]he license renewal feasibility study will lead us to make a very important decision, which is whether or not to pursue license renewal at Diablo Canyon. The time frame for making that decision would be around the end of this general rate case...or roughly 15 years before the licenses expire...If we were not -- when that time came and we were to make that very important decision not to proceed with license renewal after considering all the issues, the costs, et cetera, then we need and the state of California needs time to plan for replacement power for Diablo Canyon. (Tr. 2767:8-24, PG&E/Becker.)

Second, doing the study now takes advantage of the fact that the NRC is staffed and has processes in place to consider license renewal applications because several other utilities have already decided to pursue license renewals.

Finally, performing the study now will enable PG&E to address any needed changes to plant structures, systems, and equipment to enable an additional 20 years of operations. PG&E testified:

The sooner we know that, the sooner we can make the changes, and the sooner the benefit would occur. And that

benefit would show up in plant reliability, in safety margins, et cetera. (Tr. 2768:8-20, PG&E/Becker.)

PG&E contends that ANR/SC's and TURN's proposal to deny funding for the study is short-sighted. Diablo Canyon provides 2,200 MW of base-load capacity that would require a considerable amount of time, planning, and investment to replace. Performing the study now will allow PG&E, and the Commission, to determine in the next five years whether to apply to the NRC for license renewal – a time frame that allows PG&E and the Commission to make alternative plans to replace Diablo Canyon's 2,200 MW of capacity should the decision be made to forgo license renewal.

PG&E opposes TURN's proposal to capitalize the costs of the study as a regulatory asset that accrues AFUDC and to amortize the regulatory asset over the term of the renewed licenses. PG&E believes that project costs should not be capitalized until it is decided that a project will be pursued. PG&E has not yet decided whether to pursue renewal of the Diablo Canyon licenses. When PG&E makes that decision, PG&E will begin to capitalize the project costs.

(2) Discussion

PG&E's proposed Diablo Canyon license renewable feasibility study will be completed in 2009, which is 15 to 16 years before the expiration of the current licenses. Ratepayers should fund the study only if 15-16 years of lead time is needed to decide if Diablo Canyon should be closed and, if so, to replace the 2,200 MW of base load capacity provided by Diablo Canyon.

California currently plans for long-term power procurement through the Commission's biennial adoption of a rolling 10-year long-term procurement plan (LTPP). Given the large amount of base load capacity provided by Diablo Canyon, we conclude that it is prudent to know 10 years in advance if 2,200 MW

of capacity will need to be replaced so that replacement capacity can be obtained in an orderly, cost effective, and timely manner.

TURN's comments on the Proposed Decision state that there is no need for 10 years of advance notice to plan for 2,200 MW of replacement capacity. In D.06-11-048, the Commission approved PG&E's application to acquire 2,250 MW of new generation capacity by mid-2010. This shows, according to TURN, that PG&E can acquire replacement capacity for Diablo Canyon in 4-5 years.

TURN overlooks the fact that the 2,250 MW of capacity was part of PG&E's first 10-year LTPP approved by D.04-12-048. The purpose of the LTPP is to identify resource needs a decade in advance in order to provide sufficient time to plan for, and procure, new capacity in an orderly and cost effective manner. While TURN evidently believes there is no need for long-term planning, we believe it would be reckless and gambling with the public interest to wait until only 4-5 years are left before the Diablo Canyon licenses expire to decide whether there is a need to acquire 2,200 MW of replacement capacity. The safer and more prudent course of action is to endeavor to know 10 years in advance if the large amount of power provided by Diablo Canyon will need to be replaced.

The LTPP is issued in even numbered years and is based on a long-term forecast of electricity supply and demand contained in the biennial Integrated Energy Policy Report (IEPR) that is issued by the CEC in the previous odd-numbered year.⁹⁷ We presume that in order to be incorporated into the IEPR, a final decision to forgo license renewal (and the accompanying need to procure 2,200 MW of base load capacity) would need to be made six to 12 months prior to

⁹⁷ D.04-12-048, *mimeo.*, pp. 165-167 and COL 42, pp. 235-36.

the CEC's issuance of its IEPR. That means approximately 12 years of lead time is needed to acquire replacement power once a final decision is made not to pursue license renewal.

The decision on whether to forgo license renewal should be made in a Commission proceeding or other appropriate venue. We anticipate that such a proceeding would be complex and contentious, but could still be completed within one year. That means a completed license renewal feasibility study should be submitted to the Commission for review approximately 13 years prior to license expiration, or in the year 2011.

Pursuant to the Settlement Agreement adopted by today's Opinion, PG&E's forthcoming GRC cycle will end in December 2010. We cannot wait until the GRC cycle beginning in 2011 to fund a license renewal study because doing so would delay the completion of the study until the end of 2012, assuming it took two years to prepare the study. We conclude, therefore, that it is reasonable to fund the study during 2007-2010 so that the study will be available for the Commission's review in 2011, and the results of the study incorporated into the LTPP issued in 2014.

For the preceding reasons, we find the Settlement Agreement's provisions that authorize \$16.8 million for the Diablo Canyon license renewal feasibility study to be reasonable and in the public interest. As noted by ANR/SC and TURN, AB 1632 requires the CEC to assess key policy and planning issues affecting the future role of nuclear power plants in the State. The statute requires the CEC to issue its assessment by November 1, 2008. PG&E shall incorporate the CEC's AB 1632 assessment into its license renewal study. To avoid unnecessary duplication and overlap with the CEC's study, PG&E should defer to the extent feasible its work on its own study, and associated spending, until

after the CEC issues its findings and conclusions. PG&E should incorporate the findings and recommendations of the CEC study in its own work.

We will require PG&E to submit by no later than June 30, 2011, an application on whether to pursue license renewal. The application shall include PG&E's license renewal study and shall address (1) whether renewal of the licenses is cost effective and in the best interests of PG&E's ratepayers, (2) the CEC's AB 1632 assessment, and (3) any legislative framework that may be established for reviewing the costs and benefits of license renewal.⁹⁸ As stated previously, it is our intent that the proceeding in 2011 will result in a decision on whether to pursue license renewal based on circumstances at that time, and that the results of the proceeding will be incorporated into the CEC's 2013 IEPR and the Commission's 2014 LTPP.

ANR/SC and TURN contend that it is premature to fund a study that will be completed approximately 15 years before the first license expires in 2024. For the reasons stated previously, we believe it is prudent to have a completed study in hand 13 years prior to license expiration. Funding the study in the 2007-1010 GRC cycle will provide 13 years of lead time.

ANR/SC and TURN maintain that because PG&E has a poor record of forecasting the cost of operating Diablo Canyon and the life of major power-plant components, there can be little confidence that PG&E's study will be of any value in deciding whether to renew a license 15 years after the study is completed. We agree that the cost of operating Diablo Canyon over the years has consistently exceeded PG&E's forecasts. That does not mean, however, that there is no need

⁹⁸ The CEC's 2005 IEPR urges the Legislature to establish a framework to review license renewal costs and benefits. (2005 IEPR, p. 4.)

for a license renewal feasibility study. The issue raised by ANR/SC and TURN goes to the merits of the study results, which cannot be judged until the study is submitted to the Commission for review. There will be ample opportunity at that time for the parties to review and litigate the contents of the study.

ANR/SC and TURN are concerned that PG&E may use the study to unilaterally seek license renewal. We have already addressed this concern by requiring PG&E to submit the study to the Commission as part of an application in 2011 on whether to proceed with license renewal. If PG&E fails to do so, we agree with PG&E's observation that the Commission "has ample means to deal with PG&E's failure to comply with the Commission's order to file an application, if that should ever come to pass."⁹⁹

TURN alternatively proposes that the cost of the license renewal study be deferred as a regulatory asset and amortized over the term of the renewed licenses. TURN's proposal is consistent with the USOA. The instructions for Account 183 state, in relevant part, as follows:

This account shall be charged with all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation. If construction results, this account shall be credited and the appropriate utility plant account charged. If the work is abandoned, the charge shall be made to Account 426.5, Other Deductions, or to the appropriate operating expense account.

It makes sense to defer current expenditures for feasibility studies when a decision will be made within one or two years on whether to proceed with the

⁹⁹ PG&E opening comments on the Alternate Proposed Decision, p. 23.

project being contemplated and the project starts soon thereafter. That is not the case here. Adopting TURN's proposal could defer cost recovery until 2024, during which time the deferred costs would accrue interest based on PG&E's authorized rate of return, currently 8.79% pre-tax.¹⁰⁰ The \$16.8 million of deferred costs at the end of 2009 would balloon to \$60.2 million by the end of 2024 based on a compound annual escalation of 8.79%. The growth of the deferred costs would exceed inflation, thereby making ratepayers worse off with each passing year. We conclude that ratepayers will be better off to pay \$16.8 million during the forthcoming GRC cycle rather than a significantly higher amount in the future.

For the preceding reasons, we decline to adopt TURN's alternative proposal to defer recovery of the study costs.

(C) Additional Staffing

PG&E requested \$3 million in 2007 to address its aging workforce at Diablo Canyon by hiring and training an additional 10 engineers, 12 operators, and 15 utility workers. DRA opposed the staffing increase. DRA contended that PG&E had neither performed a cost-effectiveness study for its additional staffing proposal, nor asserted that it was safety-related or an NRC mandate.

PG&E responded that the aging workforce at Diablo Canyon is a serious issue. The average age of Diablo Canyon employees is 47.6 years. In five years, 42% of the employees at Diablo Canyon will be eligible for retirement. To replace its aging workforce.

¹⁰⁰ Settlement Agreement, Appendix G, Table 1-2, Line 33. AFUDC is not grossed up for taxes.

The Settling Parties agree that the resolution of issues regarding funding for additional staff at Diablo Canyon is subsumed in the Settlement outcome for Generation expenses. No party disputed the Settlement outcome on this matter.

We conclude that the uncontested Settlement outcome regarding additional staffing for Diablo Canyon is reasonable in light of the record, consistent with applicable law, and in the public interest.

(D) NEI Membership Dues

PG&E's forecast of Nuclear O&M expenses in 2007 included \$772,000 for membership in the Nuclear Energy Institute (NEI).¹⁰¹ TURN proposed a 50% disallowance of NEI membership fees because part of NEI's function is to advocate for nuclear power. TURN's proposal was consistent with the Commission's decision in the recent SCE GRC proceeding where the Commission reduced SCE's request for NEI membership fees by 50%. However, the Commission left open the possibility of 100% recovery of NEI fees in the future, but directed SCE to demonstrate exactly what portion of the NEI membership fee, if any, is used for the advocacy of nuclear power.¹⁰²

The Settling Parties agree that the Settlement outcome for Generation O&M expenses includes recovery of only 50% of NEI dues. In its next GRC, PG&E will present more detailed documentation supporting 100% recovery of NEI fees.¹⁰³ There was no opposition to the Settlement outcome for NEI dues.

We find the uncontested Settlement outcome for NEI funding is reasonable in light of the record, consistent with applicable law, and in the public interest.

¹⁰¹ Exhibit TURN-1, p. 9.

¹⁰² D.06-05-015, *mimeo.*, pp. 34-36.

¹⁰³ Settlement Motion, pp. 91-92.

ii. Fossil Operations

PG&E's Fossil operations currently consist of four generating units at the Humboldt Bay power plant (HBPP) that have a combined capacity of 135 MW. PG&E requested \$11.8 million for Fossil Generation O&M expenses in 2007 for the continued operation of the existing units at HBPP until new generation units come online in 2009. DRA did not oppose PG&E's request.

The Settling Parties agree that the resolution of issues regarding Fossil Generation O&M expenses is subsumed within the Settlement outcome for all Generation O&M expenses.¹⁰⁴ The Settlement also provides a one-way balancing account for certain specified HBPP costs that PG&E may be able to avoid depending on the timing of the HBPP re-power project.¹⁰⁵ The re-power project will replace four steam generators with ten 16.3 MW gas-fired generators. The on-line target for the new generators is May 2009.

(A) Issues Raised by TURN

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement to reduce Fossil Generation O&M expenses by \$2.58 million. TURN's disallowance has four components. First, TURN notes that PG&E requested \$0.6 million for boiler recertification costs in test-year 2007. Because these costs are built into the test year, PG&E will recover these costs in each of the attrition years. TURN states

¹⁰⁴ Settlement Agreement, para. 17.

¹⁰⁵ The Settlement establishes a "memorandum account" to track the authorized and actual revenue requirement for specified projects for the existing generation facilities at HBPP. The estimated revenue requirement for these projects in 2007, 2008, and 2009 is \$1.3 million, \$0.9 million, \$0.7 million, respectively. In the event it is not necessary to perform these projects, PG&E will refund any over collection in the next GRC. (Settlement Agreement, para. 30.)

that boiler recertifications are scheduled for 2007 and 2009, but not for 2008. TURN argues that PG&E should not be allowed to collect revenues for boiler recertification in 2008 when no recertification will occur that year.

Second, TURN states that PG&E has admitted that there will be no need for boiler recertification in 2009 if the HBPP re-power project is completed in 2009. In light of these facts, TURN recommends a disallowance of boiler recertification costs for 2009.

Third, PG&E requested \$1.455 million for expenses in 2007 and 2008 to plan for Clean Water Act § 361(b) cooling water intake regulations. The Settlement Agreement provides for the tracking of these costs in the HBPP memorandum account. TURN believes that most of these costs may not materialize due to PG&E's plan to re-power HBPP in 2009, and recommends that the Commission not allow recovery of these costs at the present time. Instead, PG&E should track its actual expenses in the HBPP balancing account and recoup these expenses in the next GRC if required.

Finally, TURN notes that the costs of special projects for HBPP that are tracked in PG&E's internal account MWC CJ - Fossil Generation Projects. None of these costs are included in the proposed HBPP memorandum account. Again, TURN believes that most of these costs may not materialize due to PG&E's plan to re-power HBPP in 2009. TURN states that PG&E should be allowed to track in the HBPP balancing account the actual expenses for MWC CJ in 2009 and recoup these expenses in the next GRC if required. Otherwise, PG&E may collect revenues for costs that it might never incur.

PG&E opposes TURN's proposed disallowance. PG&E argues that it is speculative to assume that it will not incur forecasted costs for the existing generation units at HBPP because PG&E has not yet obtained the necessary

permits or set a construction schedule for re-powering HBPP. Until then, PG&E believes it is prudent to proceed under the assumption that the existing generation units at HBPP will continue to operate through the GRC cycle.

PG&E generally agrees that balancing account treatment is appropriate for costs that can be avoided due to the planned re-powering of HBPP. However, PG&E opposes balancing account treatment for any expenses and capital expenditures that are not earmarked for such treatment by the Settlement.

(2) Discussion

TURN asserts that the Settlement Agreement is unreasonable because it allows PG&E to recover overstated and avoidable costs for HBPP. We agree in part and disagree in part.

We agree with TURN that PG&E's requested revenue requirement for HBPP inappropriately included \$0.6 million for boiler recertification costs in 2008, even though there will be no recertification that year. However, we disagree with TURN that the Settlement allows PG&E to recover boiler recertification costs for the year 2008. The Settlement Agreement reduces PG&E's requested O&M costs for Generation by \$6.4 million.¹⁰⁶ The Settling Parties represent that the agreed-upon amount of O&M costs reflects consideration of TURN's position. Based on this representation, we conclude that the improper boiler recertification costs for 2008 are included in the Settlement's \$6.4 million reduction to PG&E's requested O&M costs.

Regarding the remainder of TURN's proposed disallowance, TURN is correct that some forecasted O&M expenses for the current units at HBPP may be

¹⁰⁶ Settlement Agreement, para. 17.

avoided if HBPP is re-powered in 2009 as PG&E anticipates. However, the avoided O&M expenses for the retired units will be offset, at least to some extent, by O&M expenses for the new units. TURN made no effort to show there will be a net reduction of PG&E's O&M expenses from the HBPP re-powering project. Absent such a showing, we decline to adopt TURN's proposed disallowance of HBPP O&M expenses or TURN's proposed tracking of HBPP O&M expenses for the existing facilities.

On a related matter, we note that the Settlement Agreement does not specify the means that PG&E will use to establish the HBPP balancing account. We will direct PG&E to file an advice letter to establish the one-way balancing account within 30 days from the effective date of today's Opinion. The account balance shall accrue interest at the rate on prime, three month commercial paper as reported in Federal Reserve Statistical Release H-15. The Commission's Energy Division may approve the advice letter without a Commission resolution if the advice letter complies with the requirements of today's Opinion.

iii. Electric Supply Administration

PG&E requested \$42.3 million for Electric Supply Administration (ESA) expenses in 2007 to plan for and acquire electric supply-side and demand-side resources. DRA proposed \$38.0 million, for a difference of \$4.3 million. DRA's proposal was based on its belief that PG&E would reach adequate staffing levels by 2006. PG&E responded that it needs more staff in 2007 compared to 2006 because its electric procurement activities continue to expand and increase in complexity. The resolution of DRA's proposed disallowance is subsumed in the broader Settlement outcome for Generation O&M expenses.

(A) Issues Raised by TURN

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement Agreement to reduce ESA expenses by \$5.2 million in 2007. TURN asserts that PG&E's requested revenue requirement for ESA is a padded wish list. Rather than granting the wish list, TURN proposes that the Commission escalate PG&E's 2006 budget for ESA forward into 2007.

TURN provides several examples of "questionable items" to support its proposal. First, TURN claims that PG&E does not need four new staff positions for electric fuels management because (1) PG&E recently signed a settlement agreement that provides fixed prices for certain Qualifying Facilities (QFs), and (2) PG&E's new gas-fired plants will not be operational until 2008-2010.

Second, TURN believes a delay in the transition to geographic pricing for transmission indicates that two staff may not be required for all of 2007.

Third, TURN suggests that the reduction of PG&E's payments to QFs from twice per month to once per month pursuant to D.05-09-003 eliminates the need for one staff position.

Fourth, TURN argues that PG&E does not need three new staff positions in power settlements due to declining workloads for the FERC refund proceeding, refund negotiations with suppliers, and bankruptcy issues with Power Exchange (PX) and California Independent System Operator (CAISO) suppliers. TURN believes these activities will be substantially completed by 2007 and certainly before the end of the GRC cycle.

Fifth, TURN believes that PG&E might double collect its costs for one-half staff position assigned to Community Choice Aggregation (CCA). TURN claims

these costs will be charged to the Aggregators. Thus, PG&E is poised to collect the money twice – once from the Aggregators and a second time from ratepayers.

Sixth, TURN states that PG&E seeks to add one staff position in 2008 for AMI. This is inappropriate, according to TURN, because AMI-related costs are supposed to be excluded from this GRC.

Seventh, TURN contends that PG&E's request to recover costs for an Independent Evaluator of renewable solicitations is inconsistent with D.06-05-039 and Resolution E-3914.¹⁰⁷ TURN recommends that such costs be removed from this GRC and recorded in the Long Term Procurement Memorandum Account (LTPMA) in accordance with D.06-05-039 and Resolution E-3914.

Finally, TURN asserts that PG&E's request to increase staffing for long-term resource procurement from 12 to 30 positions is unsupported. TURN notes that PG&E needed only 12 staff positions to conduct its recent acquisition of Contra Costa 8 (CC8) simultaneously with major renewable and non-renewable solicitations. TURN submits that PG&E has not identified an increase in future workload relative to recent activity.

PG&E responds that TURN's proposed reduction of \$5.2 million is based on budgeted expenses for ESA in 2006. PG&E states that it is inappropriate to use the 2006 budget to forecast expenses in 2007 because of changed circumstances in 2007. PG&E also provided a point-by-point rebuttal to each of the arguments raised by TURN in support of its proposal.

¹⁰⁷ Resolution E-3914 was issued on April 21, 2005.

(2) Discussion

TURN recommends that the Commission modify the Settlement to reduce funding for ESA by \$5.2 million in 2007. TURN supports its recommendation with eight “questionable items” that purport to show that PG&E’s revenue requirement is too high. For the reasons set forth below, we find that the “questionable items” do not justify a modification of the Settlement Agreement.

First, TURN suggests that PG&E’s request for four new staff for electric fuels management is excessive because (1) PG&E has signed a QF settlement agreement that should reduce PG&E’s exposure to volatile gas prices, and (2) PG&E’s new gas-fired power plants will not be online until 2008-2010. In response, PG&E testified that the items cited by TURN will not affect PG&E’s workload. This is because PG&E expects a substantial increase in gas planning, trading, and scheduling activities for new QF gas tolling agreements. And although PG&E’s new gas-fired units will not come online until 2008 - 2010, PG&E testified that it will begin making long-term gas supply, transportation, storage, and hedging arrangements for these units in 2007.¹⁰⁸ For example, PG&E will hold requests for offers for long-term gas supply and gas storage during 2007; negotiate gas transportation agreements with gas pipelines in 2007; and begin hedging the gas positions for the new facilities in 2007.

Second, TURN doubts the need for two additional staff in 2007 to work on the CAISO Market Redesign (CMR). Because CMR has been delayed until November 2007, TURN believes the staff may not be required for all of 2007. In response, PG&E testified that although CMR has been delayed, much work needs to be done to prepare for CMR implementation. For example, PG&E will

¹⁰⁸ Exhibit PG&E-18, p. 13-3.

participate in simulations for the “new” market at the same time that it manages daily trading activities in the existing market. Market simulations will occur in the first, second and third quarters of 2007 according to the current ISO schedule, and the latter two will involve 24x7 simulations. Staff will need to be hired and trained in the new market processes prior to the November 2007 rollout.¹⁰⁹

Third, TURN suggests that a decrease in the number of payments to QFs (from two to one per month) could reduce staffing by one position. In response, PG&E testified that issuing payments is a minor factor in determining staffing needs. The steps preceding payment still need to be performed even though the number of payments will be reduced. For example, the QF meter data must be validated prior to issuing payment, and the same meter data must be submitted to the CAISO for market settlement purposes following the CAISO tariff timelines. PG&E represents that the work and timelines associated with these processes has not diminished. Moreover, PG&E represents that the reduced number of QF payments was anticipated when PG&E prepared its GRC request and was reflected in PG&E’s overall staffing request.¹¹⁰

Fourth, TURN believes that PG&E can reduce staffing by three positions due to reduced workload for the FERC refund proceeding, refund negotiations with suppliers, and bankruptcy issues with suppliers. In response, PG&E testified there are still many issues before FERC and on appeal. Additionally, claims in PG&E’s bankruptcy proceeding are still open because they are tied to the outcome of the FERC refund proceeding and global settlements. PG&E represents that none of this work will end until the conclusion of the FERC

¹⁰⁹ Exhibit PG&E-18, pp. 13-3 to 13-4.

¹¹⁰ Exhibit PG&E-18, p. 13-4.

refund proceeding, including rehearings and appeals. PG&E cannot predict when the FERC refund proceeding will end.

Fifth, PG&E requested one-half staff position for CCA-related activities. TURN asserts that PG&E will be charging Aggregators for this work, and that including it in this GRC is double-counting. PG&E testified, however, that it only charges Aggregators for work that is directly attributable to a specific Aggregator. The one-half staff position would be responsible for maintaining the software and databases required to offer CCA service, which is not directly attributable to a particular Aggregators. PG&E represents that the Commission requires utilities to recover such costs from all customers.¹¹¹

Sixth, PG&E seeks one staff position in ESA for AMI. TURN is concerned that PG&E is double counting AMI costs in the instant GRC proceeding and the AMI proceeding. However, the Settlement Agreement states that (1) the only area where PG&E presented costs in both the GRC and the AMI proceedings is Information Technology (IT),¹¹² and (2) PG&E removed the duplicative IT costs from its GRC request, as shown in Appendix G of the Comparison Exhibit.¹¹³ TURN provided no evidence to rebut the Settlement Agreement.

Seventh, TURN contends that PG&E's request to recover costs for an Independent Evaluator for renewable solicitations is inconsistent with D.06-05-039 and Resolution E-3914. However, PG&E correctly observes that Resolution E-3914 granted PG&E's request to establish the LTPMA because PG&E would incur costs for new long-term procurement activities in 2005 and

¹¹¹ Exhibit PG&E-18, pp. 13-5 to 13-6.

¹¹² Settlement Agreement, para. 51.

¹¹³ Exhibit PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.

2006 that were not included in its GRC revenue requirement.¹¹⁴ In approving the LTPMA, the Commission held that the GRC is the appropriate place to recover long-term procurement costs, stating:

SCE included its long-term procurement costs in its [GRC] revenue requirement request. While the Commission has yet to decide on the merits of SCE's request, the fact that SCE has included the long-term procurement cost in its GRC request would indicate an unequal treatment should PG&E's request to establish a memorandum account to track these costs be denied. That is, PG&E did not have an opportunity to present its long-term procurement costs for consideration by the Commission while SCE did have that opportunity. Simply because PG&E's GRC was completed before SCE's should not prevent PG&E from receiving the same opportunity to present its case. (Resolution E-3914, p. 5.)

The above statement in Resolution E-3914 indicates that the LTPMA was meant to bridge the gap between GRCs, i.e., to provide PG&E an opportunity to track and recover costs incurred in 2005 and 2006 that would have been included in PG&E's previous GRC. After 2006, costs for the Independent Evaluator are appropriately recovered through the GRC process.¹¹⁵

Finally, TURN argues that PG&E's request to increase staffing for long-term procurement from 12 to 30 is unsupported. TURN is correct that PG&E

¹¹⁴ Settling Parties' reply comments filed Oct. 5, 2006, pp. 45-47.

¹¹⁵ Resolution E-3914 states at p. 2 that PG&E's Advice Letter 2597-E requested authority to recover costs incurred through 2006 for long-term resource procurement via the LTPMA, and to recover costs incurred in 2007 and beyond in PG&E's next GRC application. Resolution E-3914 approves PG&E's request, with certain modifications. (Resolution E-3914-E, Ordering Paragraph 1.) The Resolution does not modify PG&E's request to recover costs for long-term procurement in 2007 and beyond in the instant GRC proceeding.

managed the CC8 and Long-Term Request for Offer (LT RFO) solicitation with fewer staff members than it is requesting for 2007. However, PG&E testified that although the long-term contracts mentioned above are executed, there is still much work to do in 2007 to bring these resources online, including regulatory, permitting, engineering, construction, and community outreach. PG&E represents that it cannot continue to work on the existing transactions (i.e., CC8 and seven long-term contracts resulting from PG&E's LT RFO solicitation) and future procurement processes and transactions with the existing staff.¹¹⁶

For the preceding reasons, we conclude that the Settlement Agreement provisions related to ESA are reasonable in light of the record.

c. Conclusion

Based on our review of the record, we conclude that the Settlement Agreement provisions regarding Generation O&M expenses are reasonable in light of the record, consistent with the law, and in the public interest.

3. Generation Capital Expenditures

PG&E requested funding for \$241.4 million of Generation capital expenditures in 2007, a 30% increase over 2004. By business unit, PG&E's capital expenditure request was:

Hydro: \$103.6 million.

Nuclear: \$134.4 million.

Fossil: \$3.4 million for the Humboldt Bay Power Plant.

DRA recommended that PG&E's requested capital expenditures be reduced by \$29.1 million. Other parties proposed additional reductions. The

¹¹⁶ Exhibit PG&E-18, p. 13-6.

Settlement Agreement adopts PG&E's position in full. Below, we assess the reasonableness of the Settlement outcome for Generation capital expenditures in light of the record on the issues raised by DRA and other parties.

a. Hydro Capital Expenditures

PG&E requested \$103.6 million for Hydro capital expenditures in 2007, and increase of 76.2% from 2004. PG&E testified that the primary drivers of Hydro capital expenditures are (1) new license conditions; (2) reliability projects to maintain and replace aging assets; (3) dam safety modifications in response to increasingly stringent regulations; and (4) automation and efficiency projects to increase the power provided by the existing water supply.

DRA opposed \$1.4 million that was requested by PG&E to replace the failed penstock at Coal Canyon. DRA recommended that PG&E present an analysis of the benefits of retaining Coal Canyon versus decommissioning. PG&E responded that retaining the Coal Canyon powerhouse is the least-cost alternative if downstream water users pay a fair share of the cost to rebuild and maintain the water conveyance system. PG&E also agreed to file an application with the Commission to modify the water contract with Cal Water Services.

The Settling Parties agree that the resolution of the previously described issue is subsumed in the Settlement outcome for Generation capital additions.¹¹⁷ Table 3-7 in Appendix G of the Settlement Agreement shows that the Settlement adopts PG&E's position on Hydro capital expenditures in 2007.

We find the Settlement outcome for the issues raised by DRA is reasonable in light of the record, consistent with the law, and in the public interest.

¹¹⁷ Settlement, para. 27.

i. Issues Raised by Aglet and TURN

(A) Position of the Parties

Aglet recommends that the Commission adopt Hydro capital expenditures of \$79.1 million in 2007 based on a linear trend of recorded and budgeted costs from 1998 to 2004, extrapolated to 2007. Alternatively, Aglet recommends \$82.5 million based on a three-year average of PG&E's data for 2004 - 2006.

Aglet observes that PG&E's requested capital expenditures for Hydro Generation represent an increase of 76.2% over three years. PG&E has asked for the moon, according to Aglet, without credible supporting evidence.

Aglet observes that much of PG&E's request is for re-licensing conditions. However, the timing of these expenditures is uncertain due to delays in the issuance of FERC licenses. PG&E also admits that some Hydro capital spending is "catch up" after years of limited investment due to bankruptcy and divestiture. Aglet contends that the Commission should not use catch-up spending as a basis to set rates.

Aglet urges the Commission to ignore PG&E's testimony during cross examination that the deferral of costs for delayed projects is offset by other costs for unforeseen projects that were not included in PG&E's request. Aglet states that it did not have an opportunity to test the reasonableness of such projects. It is too late for PG&E to amend its showing on Hydro projects, according to Aglet.

TURN recommends a \$12 million reduction to PG&E's Hydro plant-in-service in 2007. TURN represents that PG&E's forecast of 2007 plant-in-service assumed \$24 million of capital expenditures through 2006 to comply with FERC re-licensing conditions for the Upper North Feather River and Poe projects. However, these projects have been delayed, and PG&E currently expects re-licensing to occur in 2007. TURN estimates that both of these projects will be re-

licensed in mid-2007. Thus, rather than being in rate base for all of 2007 as PG&E originally forecast, the \$24 million would be added rate base in mid-2007, resulting in a weighted-average reduction to rate base of \$12 million in 2007.

PG&E opposes Aglet's proposal to use historical data to forecast Hydro capital expenditures in 2007. PG&E contends that the use of historical information is not useful when, as here, future conditions will be significantly different than historical circumstances.

PG&E likewise opposes TURN's proposal to reduce Hydro plant-in-service because of FERC delays in issuing hydro licenses. PG&E asserts that the FERC delays do not translate into a month-for-month delay in capital spending.

ii. Discussion

Aglet proposes to use historical data to forecast Hydro capital expenditures in 2007 rather than PG&E's project-based forecast adopted by the Settlement Agreement. We find PG&E's approach to be superior to Aglet's. PG&E testified that all of the forecasted projects are cost effective and/or required for legal, safety, or other reasons. Aglet did not attempt to show that any particular project is not necessary, cost effective, or beneficial. Thus, we have no reason to question the reasonableness of the projects. In contrast to PG&E's project-specific forecast, Aglet relies on historical data that does not reflect the regulatory and operational requirements that PG&E has testified will drive Hydro capital expenditures in 2007.

TURN recommends that the Commission reduce Hydro plant-in-service by \$12 million due to FERC's delay in renewing licenses for Hydro facilities. We decline to modify the Settlement on this basis. Although TURN has demonstrated that some capital expenditures will be postponed, there is no dispute that all capital spending for the delayed projects will be completed

during 2007. PG&E testified that the postponed capital spending will be offset, at least in part, by (1) higher AFUDC accruing on previous capital expenditures for the delayed projects,¹¹⁸ and (2) capital expenditures for new, safety-related projects that were not forecast by PG&E.¹¹⁹

Aglet urges the Commission to give no weight to PG&E's testimony that it will incur capital expenditures for projects that were not included in PG&E's request. We disagree. PG&E provided its testimony in response to a cross examination exhibit from TURN.¹²⁰ The cross-examination exhibit, which forms the basis for TURN's proposal to reduce Hydro plant-in-service by \$12 million in 2007, contains information that apparently came to light after PG&E submitted its forecast of 2007 plant-in-service.¹²¹ It would be unfair to prohibit PG&E from rebutting TURN's cross-examination exhibit as Aglet proposes. If TURN is allowed to use more recent information to discredit PG&E's showing, it is only fair that PG&E should be allowed to do the same to rehabilitate its showing.

For the preceding reasons, we conclude that PG&E has demonstrated with clear and convincing evidence that the Settlement outcome for Hydro capital expenditures is reasonable in light of the record, consistent with the law, and in the public interest.

¹¹⁸ 13 RT 964:25-965:5 and 967:12-14, PG&E/Sweeney.

¹¹⁹ The unanticipated capital expenditures include up to \$10 million to repair rock movement at the Beldon project and \$5 - \$7 million for seismic work at the Crane Valley Dam. (13 RT 1001:16-27, PG&E/Sweeney.)

¹²⁰ 13 RT 1001:16-27, PG&E/Sweeney.

¹²¹ Exhibit TURN-24, PG&E Response to DR 28-1; 13 RT 958-972, PG&E/Sweeney.

b. Nuclear Capital Expenditures

PG&E requested \$134.4 million for Nuclear capital expenditures in 2007. Aglet, ANR/SC, and TURN proposed several disallowances. DRA recommended that the Commission address in another proceeding PG&E's proposal to replace the reactor vessel heads.

The Settling Parties agree that the resolution of all issues regarding Nuclear capital expenditures is subsumed in the Settlement outcome for Generation capital additions.¹²² The Settlement adopts PG&E's request for \$195.0 million of weighted-average capital additions for Generation in 2007.¹²³

Below, we consider the reasonableness of the Settlement outcome in light of the record on the issues raised by the parties.

i. Issues Raised by the Parties

(A) Nuclear Core Plant Work

(1) Position of the Parties

PG&E requested \$36.2 million in 2007 for capital expenditures for Nuclear Core Plant Work. Aglet observes that PG&E's requested expenditures in 2007 are nearly ten times higher than its recorded expenditures of \$3.8 million in 2004. The only support in PG&E's application for dramatically higher capital spending in 2007 is a list of seven project titles.

PG&E's rebuttal testimony offered nine "Examples of 2007 capital projects" and a list of requested capital expenditures. Aglet states there is no narrative explanation or work papers supporting the list. The total 2007 capital

¹²² Settlement Motion, p. 101; Settlement Agreement, para. 27.

¹²³ Settlement Agreement, Appendix G, Table 3-7, Line 24.

expenditures for the nine projects is \$11.7 million, less than one third of the requested capital expenditures of \$36.2 million.

Aglet contends that a listing of project titles and a brief explanation of \$11.7 million of the requested spending is insufficient support for \$36.2 million of capital expenditures. Further, Aglet notes that none of the capital projects listed by PG&E is critical, which leads Aglet to believe that some of the projects might not be funded depending on the availability of funds.

Aglet proposes that the Commission approve \$13.1 million for Core Plant Work capital expenditures in 2007. Aglet's proposal is based on the three-year average of recorded and forecasted capital expenditures for 2004, 2005, and 2006.

PG&E responds that it has adequately identified the specific projects for its requested capital expenditures for Core Plant Work. PG&E argues that it is not appropriate to rely on historical information as recommended by Aglet when better, project-specific information has been presented.

(2) Discussion

PG&E requested \$36.2 million for Core Plant Work capital expenditures in 2007. The Settlement Agreement adopts PG&E's request. To support its request, PG&E provided (1) a list of over 200 capital projects that comprise its requested capital expenditures, and (2) a description of nine of the projects with associated capital expenditures of \$11.7 million.¹²⁴ All of the projects identified by PG&E appear to be necessary and useful to the provision of utility service.

Aglet asserts that PG&E failed to support its requested capital expenditures. We disagree. PG&E provided a detailed breakdown of its

¹²⁴ Exhibit PG&E-18, pp. 11-10 to 11-12 and Table 11-1.

requested capital expenditures for Core Plant Work. Aglet did not attempt to demonstrate that any particular project is unreasonable or would not be undertaken by PG&E. Absent such a showing, we decline to adopt Aglet's proposal to reduce capital spending for Core Plant Work by nearly two thirds. Instead, we find that PG&E has demonstrated with substantial, clear, and convincing evidence that the Settlement outcome for nuclear Core Plant Work is reasonable in light of the record.

Although we decline to adopt Aglet's recommendation, we share Aglet's concern about the dramatic increase in capital expenditures for Core Plant Work since 2004. As noted by Aglet, the Settlement provides \$36.2 million for Core Plant Work capital expenditures in 2007, which far exceeds PG&E's recorded expenditures of \$3.8 million in 2004. Further, all of the projects are ranked as less-than-critical in PG&E's project-priority ranking system.

The high level of capital expenditures provided by the Settlement relative to historic spending, combined with funding for less-than-critical projects, indicates that PG&E has some flexibility as to whether it will actually use all the funds provided by the Settlement for Core Plant Work. We invite parties in the next GRC proceeding to closely scrutinize PG&E's capital spending for Core Plant Work during 2007-2010 to determine whether PG&E spent all the capital funds authorized by today's Opinion for the 200-plus capital projects for Core Plant Work listed in Chapter 11 of Exhibit PG&E-18. If PG&E has not, we do not anticipate authorizing capital expenditures for these projects a second time unless PG&E can demonstrate that it had to divert funds to other Core Plant Work not listed in Exhibit PG&E-18.

(B) Radioactive Waste Storage Facility

(1) Position of the Parties

Diablo Canyon's spent nuclear fuel is currently stored on site in large pools of water. The storage capacity of the pools is nearly exhausted. To allow Diablo Canyon to operate past 2010, PG&E is currently building an independent spent fuel storage facility (ISFSF). The ISFSF, which is permitted by the NRC, consists of a pad on which shielded casks of spent fuel will be stored.

PG&E requested \$3.4 million for ISFSF capital expenditures in 2007 and \$8.9 million in expense.¹²⁵ The Settlement Agreement adopts PG&E's requested capital expenditures for the ISFSF.¹²⁶ Expenses for the ISFSF are subsumed in the Settlement outcome for Generation O&M expenses.¹²⁷ The Settlement Agreement adopts \$450.6 million for Generation O&M expenses in 2007, which is \$6.4 million less than PG&E requested.¹²⁸

ANR/SC argues that ratepayer funding for the ISFSF is premature for several reasons. First in June 2006, the Ninth Circuit Court of Appeals ruled that the NRC should supplement the environmental impact statement prepared in connection with the NRC's authorization of the ISFSF to consider the environmental impacts of terrorist attacks.¹²⁹ ANR/SC contends that ratepayer funding for the ISFSF project should not be allowed at this time because the project may need to be redesigned and reconstructed.

¹²⁵ Exhibit PG&E-3, Chapter 4, Tables 4-1a and 4-11 on pp. 4-55 and 4-65, respectively.

¹²⁶ Settlement Agreement, Appendix G, Table 3-7, Line 32.

¹²⁷ Settlement Motion, p. 88.

¹²⁸ Settlement Agreement, para. 17.

¹²⁹ *San Luis Obispo Mothers for Peace v. NRC*, 449 F.3d 1016 (9th Cir. 2006).

Second, the NRC held that PG&E may proceed with construction of the ISFSF at its own financial risk.¹³⁰ Because PG&E is at risk, ANR/SC believes there is no need for ratepayers to fund the ISFSF until there is resolution of the NRC proceeding pursuant to the Ninth Circuit order.

Third, there has been legislation pending in Congress since February 2005 that calls for spent nuclear fuel to be transferred to the federal government.¹³¹ ANR/SC contends that it would be irresponsible to force ratepayers to fund costs for a storage facility at Diablo Canyon that might not be used.

Finally, ANR/SC believes that onsite storage of high-level nuclear waste poses a substantial threat to public health and safety. ANR/SC urges the Commission to require hardened onsite storage (berms and/or bunkers) and dispersal of the casks over the site to protect against radioactive fallout in the event of a terrorist attack or other acts of malice.

PG&E responds that the Ninth Circuit did not revoke PG&E's license from the NRC to construct and operate the ISFSF. Further, an NRC order issued on September 6, 2006, denied a request filed by the Mothers for Peace to stop PG&E's construction and operation of the ISFSF.¹³²

PG&E submits that it is in the public interest to move forward with the ISFSF. The existing spent-fuel pools will be full in 2010. If the ISFSF is not built and ready to store spent fuel, the NRC will not allow Diablo Canyon to continue operations, and PG&E's customers will lose this base-load generating resource and bear the cost of replacement power.

¹³⁰ NRC Memorandum and Order CLI-06-23, September 6, 2005.

¹³¹ H.R. 4538 and S.2099.

¹³² NRC Memorandum and Order, Docket No. 72-26-ISFSI (September 6, 2006).

PG&E agrees with ANR/SC that PG&E does bear the financial risk for proceeding with the ISFSF. PG&E defines that risk as recovery of only abandoned-plant cost (and no AFUDC) in the event the ISFSF is not completed.

(2) Discussion

It is likely that Diablo Canyon will continue to operate after 2010. We believe that it is prudent to move forward with construction of the ISFSF for the reasons cited by PG&E. Therefore, we decline to adopt ANR/SC's request to modify the Settlement Agreement to deny funding for the ISFSF.

We appreciate ANR/SC's efforts to safeguard the nuclear waste accumulating at Diablo Canyon from terrorist attack. We encourage ANR/SC and PG&E to work cooperatively to explore cost-effective options for protecting the nuclear waste at Diablo Canyon from attack, such as covering the dry-storage casks with high mounds of dirt.

(C) Reactor Vessel Head Replacement Project

(1) Position of the Parties

PG&E requested a total of \$141 million of capital expenditures over the 2007 GRC cycle to replace the Diablo Canyon reactor vessel heads (RVHs). DRA proposed that PG&E file a separate application for the RVHs. PG&E responded that the RVHs need to be replaced, and that DRA and others could review the completed project in the next GRC. The Settlement adopts PG&E's request.¹³³

ANR is concerned about ever rising costs for Diablo Canyon. When Diablo Canyon was built, PG&E forecast that the RVHs would last the life of the plant. PG&E now says it needs to replace the RVHs half way through the

¹³³ Settlement Agreement, para. 27, and Appendix G, Table 3-7, Line 24.

current license period. ANR/SC also observes that the forecast cost for RVHs has risen from \$67 million in the recent steam generator replacement proceeding to \$141 million today. ANR/SC adds that PG&E has not shown a need for new RVHs and, therefore, there should not receive funding for new RVHs.

(2) Discussion

The Settlement allows PG&E to replace its RVHs while allowing DRA and others to review the completed RVH project in the next GRC.¹³⁴ We find this outcome to be reasonable in light of the record and in the public interest.

ANR/SC asserts that it is not necessary to replace the RVHs without citing any supporting evidence. In contrast, PG&E presented written and oral testimony explaining why it is necessary to proceed with this project during this GRC cycle. PG&E testified:

By the end of the current operating cycle on Unit 1, both reactor vessel heads at [Diablo Canyon] will be in the 'high susceptibility' category (as defined by the Nuclear Regulatory Commission) for the onset of cracking in the Reactor Vessel Head penetration nozzles. Nearly all of the domestic pressurized water reactors in this category have already replaced or have ongoing projects to replace their reactor vessel heads. (Exhibit PG&E-18, p. 11-9, L: 18-23.)

Furthermore, PG&E testified that it will be more costly if the RVHs are not replaced because the current RVHs will likely require significant additional maintenance.¹³⁵ Specifically, when questioned why PG&E has proposed to replace the RVHs in 2008 and 2009, PG&E's witness responded:

¹³⁴ Settlement Motion, p. 100.

¹³⁵ 29 RT 2734:8-25, PG&E/Becker.

[B]ased on extensive industry experience, the Diablo Canyon reactor vessel heads are about to enter a time period where repairs are becoming likely during refueling outages. And the costs of refueling outages escalate greatly once the repairs start to occur.... So the time to pursue such a project is now, not after those repairs start to occur. The cost to the ratepayer if we waited for the repairs to start to occur would be considerably more costly. (29 RT 2734:13-25, PG&E/Becker.)

For the preceding reasons, we decline to adopt ANR/SC's recommendation. However, we share ANR/SC's concerns about the ever rising costs of maintaining and operating Diablo Canyon. As noted in the Settlement Motion, DRA and other parties can review the cost of the RVH replacement project in the PG&E's next GRC. We encourage ANR/SC to do so.

ii. Conclusion re: Nuclear Capital Expenditures

We find the Settlement Agreement provisions regarding Nuclear capital expenditures are reasonable in light of the record. PG&E provided extensive and generally persuasive testimony supporting its requested Nuclear capital expenditures, which is adopted by the Settlement. Aglet, ANR/SC, and TURN raised several objections to the Nuclear capital expenditures adopted by the Settlement Agreement, all of which we find unconvincing for the previously stated reasons.

We also find the Settlement provisions regarding Nuclear capital expenditures are consistent with applicable law, as there is no credible evidence that any part of the Settlement outcome for Nuclear capital expenditures is contrary to any law, regulation, court order, or Commission decision.

Finally, we find that the level of Nuclear capital expenditures set forth in the Settlement Agreement is in the public interest, as this level will enable PG&E

to continue to operate its 2,200 MW Diablo Canyon Power Plant to provide a large amount of reliable, base load electric power to its customers.

c. Fossil Capital Expenditures

i. Position of the Parties

PG&E requested \$3.4 million for Fossil Generation capital expenditures in 2007, \$1.7 million in 2008, and \$8.3 million in 2009. All of the requested capital expenditures are meant to keep the existing generating units at HBPP operating until new units come online in mid-2009. However, the timeframe for the new units is somewhat uncertain, as PG&E has not yet obtained construction permits or developed a construction schedule.

DRA recommended a disallowance of all capital expenditures for HBPP based on PG&E's plans to replace the existing power plant in mid-2009.

The Settling Parties agree to provide rate recovery for some specified capital projects for the continued operation of the existing generation units at HBPP. These projects are listed in Appendix C of the Settlement Agreement. The estimated revenue requirement for these projects is \$1.3 million in 2007, \$0.9 million in 2008, and \$0.7 million in 2009. The Settling Parties also agree that PG&E will establish a memorandum account to track the difference between the authorized and actual revenue requirement associated with these projects, and, in the next GRC, will refund any unused revenue requirements.¹³⁶

TURN supports memorandum account treatment for HBPP capital expenditures but opposes the provision in the Settlement Agreement allowing PG&E to collect these funds as part of base rates. TURN believes these capital

¹³⁶ Settlement Agreement, para. 30.

projects are unlikely to occur absent major setbacks in the construction of replacement generating units on the site. To the extent that these projects prove necessary, TURN states that PG&E should record the capital costs in the memorandum account and seek recovery in the next GRC.

The Settling parties urge the Commission to reject TURN's proposed modification of the Settlement. They opine that the Settlement Agreement's memorandum account treatment of capital expenditures adequately addresses TURN's concerns about whether these funds will ever be spent.

ii. Discussion

We decline to adopt TURN's proposed modification of the Settlement Agreement. HBPP provides essential load support to the surrounding region. There is no dispute that the requested capital expenditures for the existing facilities at the HBPP will be necessary in the event there is a delay in re-powering HBPP. We believe that it is prudent to plan for these capital expenditures because, until the proposed re-powering project is reviewed by the responsible agencies and the necessary permits for construction and operation of the new units are received, there is uncertainty regarding when the existing units at HBPP will be retired.¹³⁷ The HBPP memorandum account provides sufficient protections to ratepayers in the event the relatively modest capital expenditures adopted by the Settlement prove unnecessary.

For the preceding reasons, we conclude that the Settlement outcome for Fossil Generation capital expenditures is reasonable in light of the record, consistent with the law, and in the public interest.

¹³⁷ Exhibit PG&E-18, p. 12-4.

d. Generation Plant

PG&E forecasted \$11.177 billion of weighted-average plant in 2007 for Generation UCCs. DRA forecasted \$10.928 billion, for a difference of \$249.3 million. The Settlement adopts \$10.954 billion, which is \$223.3 million less than PG&E requested and \$26.1 million more than DRA recommended. The reduced amount adopted by the Settlement compared to PG&E's request is due almost entirely to nuclear fuel, which is addressed below.

We find the Settlement outcome on this matter is reasonable in light of the record, consistent with applicable law, and in the public interest.

e. Nuclear Fuel Inventory

PG&E sought to include nuclear fuel in rate base. PG&E forecasted a weighted-average nuclear fuel inventory of \$221.9 million in 2007.

DRA opposed PG&E's request to include nuclear fuel in rate base. DRA contended that doing so would cost ratepayers more, since ratepayers would bear the carrying costs for fuel inventory at the weighted cost of capital rather than the three-month commercial paper rate. DRA recommended that PG&E recover its nuclear fuel inventory carry costs in its Energy Resource Recovery Account (ERRA) proceeding consistent with long-standing Commission policy.

The Settling Parties agree to exclude nuclear fuel from PG&E's rate base.¹³⁸ The carrying costs for nuclear fuel inventory will continue to be collected through the ERRA at the short-term interest rate. No party objected to the Settlement outcome on this matter.

¹³⁸ Settlement, para. 43.

We find the uncontested Settlement outcome for nuclear fuel inventory is reasonable in light of the record, consistent with Commission precedent that excludes nuclear fuel inventory from rate base,¹³⁹ and in the public interest.

E. Common and Miscellaneous Revenues, Expenses, and Capital

1. Other Operating Revenues

Other Operating Revenues (OORs) are revenues that are not directly derived from the provision of public utility services. OORs are estimated separately and reduce the utility's revenue requirement.

PG&E initially forecast that OORs in 2007 would be \$113.9 million. PG&E subsequently agreed to several minor increases proposed by TURN. With these concessions, PG&E's revised forecast was \$114.8 million.

The Settling Parties agree that OORs will be \$116.2 million in 2007.¹⁴⁰ The Settlement Agreement reflects the Settling Parties' agreement to increase the fees for bounced checks and reconnection fees.¹⁴¹

TURN was the only party to contest PG&E's forecast of OORs. As discussed below, TURN recommends that the Commission modify the Settlement to increase OORs for several items. The Settling Parties respond that the Settlement Agreement increases OORs by \$1.4 million above PG&E's litigation position to reflect TURN's positions on OORs. They contend that TURN's recommendation to modify the Settlement to increase OORs would constitute double counting.

¹³⁹ See, for example, D.06-05-016, *mimeo.*, pp. 271-275.

¹⁴⁰ Settlement, para. 44.

¹⁴¹ PG&E's litigation position for OORs also reflected increased fees.

Below, we assess the reasonableness of the Settlement outcome for OORs in light of the record on the issues raised by TURN.

a. Issues Raised by TURN

i. Reconnection Fees

(A) Position of the Parties

PG&E forecasted \$2.9 million of revenue from reconnections charges in 2007 based on 2004 recorded data. TURN projects \$3.2 million based on 2005 recorded data. TURN testified that there is a clear upward trend in revenues for the five-year period ending in 2005. In light of this upward trend, TURN contends that the 2005 recorded data provides a better basis to forecast 2007 revenues than the 2004 data used by PG&E.

PG&E disagrees with the validity of TURN's trending process. TURN used only the five most recent years even though 10 years of data was available. PG&E states that looking at the data over a longer period shows that recorded reconnection fees have increased four times and decreased four times over the period 1996-2005. This shows, according to PG&E, that reconnection fees fluctuate from year to year and do not follow a trend as suggested by TURN.

(B) Discussion

The record shows that for the 10-year period of 1996-2005, there was a clear down trend in reconnection fees during 1996-2000 and a clear up trend since then.¹⁴² In light of the clear uptrend, we conclude that TURN's forecast of 2007 reconnection fees using 2005 recorded data is superior to PG&E's forecast using 2004 recorded data.

¹⁴² 12 RT 809:23 – 810:2, PG&E/Hartman.

The difference between PG&E's and TURN's positions is \$0.3 million. The Settling Parties assert that adopting TURN's position would constitute double counting because the Settlement Agreement adopts forecasted OORs that exceeds PG&E's litigation position by \$1.4 million. We agree with the Settling Parties on this point. TURN was the only party to contest PG&E's forecast of OORs. Consequently, it is reasonable to assume that the amount of OORs adopted by the Settlement Agreement in excess of PG&E's litigation position can only be attributed to TURN.

ii. Timber Sales

(A) Position of the Parties

PG&E forecasted that revenues from timber sales in 2007 would be \$2.0 million. TURN forecasted \$2.8 million. TURN's forecast is equal to the four-year average of actual timber revenues in 2004 and 2005, and PG&E's forecast of timber revenues in 2006 and 2007. TURN contends that using a four-year average is reasonable because it smoothes out year-to-year fluctuations.

PG&E responds that its forecast is based on expected circumstances in 2007 and, therefore, is better than TURN's retrospective approach.

(B) Discussion

PG&E testified that its forecast of timber sales in 2007 is based on current timber stand conditions and environmental requirements. Using this information, PG&E forecasts that a much higher proportion of the timber harvested in 2007 will be red and white fir. PG&E represents that these trees are low-value, which will depress timber revenues in 2007.¹⁴³

¹⁴³ Exhibit PG&E-18, p. 9-3.

TURN does not challenge the veracity of PG&E's testimony. Rather, TURN contends a four-year average provides a better forecast for the 2007 test year and the GRC cycle as a whole.

We find that PG&E and TURN have both presented reasonable forecasts, but that PG&E's forecast will likely be more accurate, at least in 2007, because it is based on current conditions and requirements rather than historical circumstances. We conclude, therefore, that the Settlement outcome on this matter is reasonable in light of the record.

iii. Work Requested by Others

(A) Position of the Parties

PG&E forecasted that it would incur \$21.0 million of expenses in 2007 for work requested by others (WRO) and receive \$8.5 million of OORs for WRO. TURN recommends that the forecasted OORs for WRO be increased by \$1.7 million. TURN observes that PG&E forecasts a significant decrease in the proportion of WRO expenses recovered through WRO revenues. Specifically, total WRO revenues in 2004 comprised 47.7% of total WRO expenses, whereas PG&E's 2007 forecast has revenues at only 35% of total expenses. The result is a 50% increase in costs to ratepayers (\$10.2 million in 2004 to \$15.7 million in 2007).

TURN believes the main reason why WRO revenues decrease relative to expenses is that PG&E projects that non-generation WRO expenses will increase faster than associated revenues. Non-generation WRO revenues were 51.2% of total non-generation WRO expenses in 2004. PG&E projects that non-generation WRO revenues will fall to 42.2% of non-generation WRO expenses in 2007.

TURN recommends that the Commission increase forecasted WRO revenues by \$1.7 million to restore the proportionality between WRO revenues

and costs. Under TURN's adjustment, non-generation WRO revenues will remain at 51.2% of non-generation WRO expenses.

PG&E opposes TURN's proposal. PG&E states that it is important to recognize there are two categories of WRO expenses: (1) those expenses that are reimbursable, which should match related revenues (Reimbursable WRO); and (2) those expenses that are not reimbursable (Non-Reimbursable WRO). The forecast of Reimbursable WRO has no impact on PG&E's revenue requirement, since the forecasted expenses are exactly offset by matching forecasted revenues. Only the forecast of Non-Reimbursable WRO affects revenue requirement. Consequently, PG&E's forecasted increase in net WRO expenses relates solely to Non-Reimbursable WRO.

PG&E incurs Non-Reimbursable WRO expense in three areas: relocations, generation interconnects, and pre-parallel inspections. With respect to relocations, PG&E agreed to DRA's proposal to reduce PG&E's projected expenses for 2007 from \$11.5 million to \$10.2 million. The \$10.2 million figure for 2007 is the equal to PG&E's recorded relocation costs in 2004, without inflation. PG&E states that TURN has incorrectly used PG&E's original \$11.5 million figure rather than adjusted amount of \$10.2 million.

With respect to generation interconnects, PG&E agreed to DRA's proposal to reduce its projected expenses from \$3.5 million to \$1.6 million. PG&E states that TURN has incorrectly used PG&E's original \$3.5 million figure rather than the adjusted amount of \$1.6 million.

With respect to pre-parallel inspections, PG&E did not agree to any reduction of its projected expenses of \$0.7 million in 2007, even though DRA recommended zero funding. PG&E objected to DRA's proposal because the work does exist and PG&E is obligated to perform these inspections upon a

customer's request. Furthermore, in the last GRC these cost were categorized as transmission expenses that are not recovered in GRC proceedings. In 2005, PG&E began recording this work under distribution assets. PG&E's recorded expenses for 2004 (recorded in transmission) were \$662,000. PG&E's 2007 forecast of \$711,000 represents a modest increase from 2004 of less than 3% per year. PG&E submits that its forecast is reasonable and should be adopted.

(B) Discussion

TURN's principal concern is the decline in the ratio of WRO revenues to WRO expenses from 2004 to 2007. Seeing this decline, TURN concludes that something must be awry, and proposes that the Commission increase forecasted WRO revenues by \$1.7 million in 2007 to restore the ratio to its 2004 level.

TURN's proposal is flawed in two respects. First, it rests on a mistaken assumption that PG&E requests \$15.7 million of expense for Non-Reimbursable WRO in 2007 compared to \$10.2 million in 2004. As noted by PG&E, the \$15.7 million figure that TURN uses in 2007 does not reflect PG&E's concessions. When PG&E's concessions are reflected (\$1.3 million for relocations and \$1.9 million for generation interconnects), the amount requested by PG&E in 2007 for Non-Reimbursable WRO drops to \$12.5 million, not the \$15.7 million figure cited by TURN.¹⁴⁴

The remaining differences of \$2.3 million between the 2004 recorded expenses for Non-Reimbursable WRO cited by TURN (\$10.2 million) and the amount being requested by PG&E in 2007 (\$12.5 million) is entirely attributable to generation-related items, i.e., generation interconnects (\$1.6 million) and pre-

¹⁴⁴ \$12.5 million is the sum of: \$10.2 million (Exhibit PG&E-18, p. 17-2, L: 25) plus \$1.6 million (PG&E-18, p. 17-3, L: 18) plus \$0.7 million (PG&E-18, p. 17-3, L: 22.)

parallel inspections (\$0.7 million). TURN does not dispute the reasonableness of PG&E's forecasted expenses of \$2.3 million for these items. Rather, TURN's concern is focused on what it saw as an excessive increase in non-generation expenses.¹⁴⁵ In fact, as described above, if the two generation related items – generation interconnects and pre-parallel inspections – are disregarded, there is no increase in the Non-Reimbursable WRO expense for non-generation items.

The second flaw in TURN's proposal to increase WRO revenues in 2007 by \$1.7 million is that it is based entirely on the premise that there is fixed ratio of WRO revenues to WRO expenses. Underlying this premise is the implicit assumption that Reimbursable WRO revenues and expenses move in tandem with Non-Reimbursable WRO expenses. However, Reimbursable WRO is different than Non-Reimbursable WRO. TURN did not demonstrate a correlation between these two expense items; nor did it provide a rationale for why these items must move in tandem. Because Reimbursable WRO and Non-Reimbursable WRO are for different services and are triggered by different needs, they cannot be expected to remain in a constant ratio over time.

For the preceding reasons, we find the Settlement outcome for WRO revenues to be reasonable in light of the record. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to increase the forecasted OOR in 2007 by \$1.7 million. In any event, this issue is largely moot. For the reasons described previously, the Settlement Agreement appears to adopt at least some of TURN's position on WRO (and other OOR issues).

¹⁴⁵ TURN Comments, pp. 75-76.

2. Administrative and General Expenses

Administrative and General (A&G) expenses are common costs that benefit all of PG&E's lines of business. PG&E conducted an A&G Study (Study) to determine the amount of A&G expense that should be included in its GRC revenue requirement. The Study examined 42 PG&E (Utility) departments and 26 PG&E Corporation (Holding Company) departments. The Study identified each department's total labor, materials, and contract costs. The Study then used an elaborate, multi-step process to allocate these costs among all the UCCs, including those relevant to this GRC.

The Settlement Agreement adopts total Company A&G expenses of \$772.3 million in 2007. This outcome is \$34 million less than PG&E's request of \$806.3 million and \$70.1 million more than DRA's recommendation of \$702.2 million. The Settlement also allocates the total Company A&G expenses among the UCCs. The amount of A&G expenses allocated to GRC-related UCCs is \$709.4 million in 2007, which is \$32.8 million less than PG&E requested and \$66.5 million more than DRA recommended.¹⁴⁶ The Settling Parties agree that the allocation A&G expenses among the UCCs adopted by the Settlement should be used to determine the A&G expenses in other proceedings until the next GRC.

DRA and TURN raised numerous issues regarding PG&E's requested A&G expenses. Below, we assess the reasonableness of the Settlement outcome for A&G expenses in light of the record on these issues. For convenience, we divided these issues into the following categories: (1) general matters and corporate services; (2) Holding Company issues; (3) employee compensation; (4) other A&G expenses; and (5) unbundling.

¹⁴⁶ Settlement Agreement, Appendix A, Line 16.

a. General Matters and Corporate Services

i. Issues Addressed by DRA

(A) Normalized Adjustments

DRA proposed a disallowance of \$1.145 million for “normalized adjustments.” The costs in question were for employee recognition awards, employee lunches and dinners, staff parties, and entertainment activities. PG&E responded that the costs in question are a customary part of doing business, and that failure to recover these costs would place PG&E at a competitive disadvantage in terms of employee recruitment and retention. The Settling Parties agree that the resolution of DRA’s normalized adjustments is subsumed in the overall Settlement outcome for A&G expenses.

(B) Time Tracking

DRA expressed concern that PG&E does not have a formal time-tracking system to record time and costs in the Public Policy and Governmental Affairs (PP&GA) departments, particularly those with below-the-line activities. DRA believed that the lack of a time-tracking system could result in excessive charges to ratepayers. The Settling Parties agree that PG&E will implement a time-tracking system no later than January 1, 2008.

(C) Corporate Services

PG&E’s Corporate Services includes all the Utility departments that provide services to the Company as a whole. DRA performed an in-depth review of Corporate Services. Based on its review, DRA concurred with much of PG&E’s requested expenses for Corporate Services in 2007. The areas of agreement included \$1.45 million for the Utility President and CEO; \$7.504 million for Corporate Accounting functions; \$1.477 million for Industrial Relations; \$1.0 million for the Compensation department; \$1.883 million for the

Professional Staffing and Diversity department; \$2.567 million for Corporate Security; \$0.681 million for the office of the Vice President (VP) of ISTS; \$25.7 million for legal settlements and judgments; and \$0.5 million for the office of the PG&E's Senior Vice President (SVP) and Senior Counsel.

DRA also proposed numerous disallowances of Corporate Services expenses. Most of DRA's proposed disallowances are summarized in the following table:

DRA's Proposed Disallowances of Corporate Services Expenses in 2007 (\$ Millions)		
	PG&E Request	DRA Disallowance
Utility Corporate Secretary	\$0.82	\$0.82
Utility Law Department	\$37.20	\$3.60
Health, Safety, and Claims	\$72.70	\$0.26
Utility SVP and CFO	\$0.78	\$0.35
Business and Financial Planning	\$1.53	\$0.26
Utility VP and Controller	\$3.93	\$1.75
Management Reporting	\$5.17	\$1.57
Capital Accounting	\$2.28	\$0.44
Accounts Payable	\$2.67	\$0.38
Utility Risk Management	\$5.54	\$1.50
Public Policy and Gov. Affairs	\$30.50	\$8.50
SVP Human Resources	\$0.80	\$0.29
HR Operations, Services & Systems	\$5.56	0.63
Supply Chain Purch. Operations	\$5.09	\$1.04
Total	\$174.57	\$21.39

DRA's proposed disallowances in the above table exclude DRA's "normalized adjustments" summarized previously. The bulk of DRA's proposed disallowances shown in the above table were based on its finding that PG&E's requested expenses were excessive when compared to historical expenses and staffing for Corporate Services.

PG&E responded that DRA's analysis of historical data overlooked a substantial amount of data that demonstrated PG&E's requested expenses were reasonable. PG&E also asserted that its expenses would be higher in 2007 compared to historical trends because of costly new requirements (e.g., Sarbanes-Oxley) and programs (e.g., reinstatement of PG&E's commercial paper program).

(D) Discussion

The resolution of the issues raised by DRA regarding A&G expenses is subsumed within the overall Settlement outcome for A&G expenses. The Settlement Agreement provides PG&E with \$709.4 million for A&G expenses in 2007, which is \$32.8 million less than PG&E requested.¹⁴⁷ We presume the Settlement Agreement, by providing PG&E with less money than it requested, reflects DRA's litigation position to some degree.

We commend DRA for the considerable effort it invested in reviewing and analyzing A&G expenses. Absent the Settlement Agreement, we would have adopted at least some of DRA's proposed disallowances for A&G expenses. TURN contested certain aspects of the Settlement outcome, which we address below. Putting aside the matters disputed by TURN, we find the Settlement outcome for general A&G matters and Corporate Services is reasonable in light of the record, consistent with applicable law, and in the public interest.

¹⁴⁷ Settlement Motion, p. 108.

ii. Issues Raised by TURN

(A) Capitalization of A&G Costs

(1) Position of the Parties

PG&E proposed seven separate capitalization rates for different categories of A&G expenses, including 32.61% for pensions, benefits, and workers' compensation. PG&E also proposed a capitalization rate of zero percent (0.00%) for some A&G expenses, including certain human resource (HR) functions. DRA agreed with PG&E's proposed capitalization rates, which the Settlement adopts.

TURN recommends that the Commission modify the Settlement to adopt a single capitalization rate of 33.09% for all A&G costs, which is equal to the average rate in 2005 and 2006 for pension, benefits, and workers' compensation costs (32.05% and 34.13%). Adopting TURN's proposal would reduce A&G expenses in 2007 by \$9.8 million compared to PG&E's request.

TURN claims that PG&E provided contradictory testimony regarding its proposed capitalization rate of 32.61% for pensions, benefits, and workers' compensation. On the one hand, PG&E stated in rebuttal testimony that its proposed rate of 32.61% for 2007 is based on 2004 data. On the other hand, PG&E's witness testified during cross-examination that PG&E's capitalization rate of 32.05% in 2005 was based on 2004 data. TURN argues that the fact that PG&E used the same 2004 data to calculate different capitalization rates for 2005 and 2007 casts doubt on PG&E's proposed capitalization rate of 32.61% in 2007.

TURN opposes PG&E's capitalization rates for other HR functions that range from 0% to 32%. For example, PG&E requests a capitalization rate of zero percent (0.00%) for the Benefits department based on the claim that this department would not avoid any costs in the absence of a capital program. TURN argues that PG&E's rationale makes no sense. The Benefits department

provides services to employees assigned to construction projects and, therefore, a portion of the department's costs should be capitalized.

PG&E opposes TURN's uniform capitalization rate of 33.09%. PG&E states that its multiple capitalization rates are based on a department-specific study that was conducted in conformance with the incremental standard prescribed by the Commission and the USOA. Under this approach, each A&G department identified to what extent the department's costs would be avoided in the absence of ongoing construction activities. The avoided costs were then used to determine appropriate capitalization rates. PG&E asserts that TURN has not shown any legitimate flaws in PG&E's approach.

(2) Discussion

TURN recommends a uniform capitalization rate of 33.09% for all A&G departments. To support its recommendation, TURN criticizes PG&E's capitalization rate of zero percent (0.00%) for some A&G departments, and cites PG&E's Benefits department as an example of a department that should capitalize some of its costs. TURN overlooks the fact that the Benefits department provides services to 17,000 retirees.¹⁴⁸ The absence of a capital program would not affect the services provided to retirees. Thus, the work of the Benefits department is driven more by the number of beneficiaries than by the number of employees assigned to construction projects. We concluded that PG&E's proposed capitalization rate of 0.00% for the Benefits department is more reasonable than TURN's proposed rate of 33.09%.

¹⁴⁸ Exhibit PG&E-6, p. 18-A24.

The record shows that PG&E determined its capitalization rates on a department-by-department basis using an incremental approach. Using this approach, each department determined what costs would be avoided in the absence of an ongoing construction program. The avoided costs were then used to calculate a capitalization rate.¹⁴⁹ In contrast to PG&E's approach, TURN proposes a single capitalization rate for all A&G departments. The calculations used by TURN to develop its proposed rate did not reflect the disaggregation of department costs into cost pools (capital, below-the-line, PG&E Corporation, and affiliates) or the effects of A&G expenses already capitalized through FERC Account 922. PG&E did take these items into consideration when calculating its capitalization rates. Thus, PG&E's approach for calculating capitalization rates is more precise than TURN's.

We conclude for the preceding reasons that there is more support in the record for PG&E's multiple capitalization rates than for TURN's single rate, and that the Settlement's adoption of PG&E's capitalization rates is reasonable in light of the record.

(B) Law Department Costs for Outside Counsel

(1) Position of the Parties

PG&E's requested \$19.6 million for outside legal counsel expenses in 2007. PG&E's request was based on recorded expenses for 2005. DRA and TURN both recommended \$16.2 million based on 2004 recorded expenses. The Settlement states that the resolution of this matter is subsumed within the overall Settlement outcome for A&G expenses.

¹⁴⁹ Exhibit PG&E-18, p. 34-22.

TURN argues that PG&E's use of 2005 data instead of 2004 data is rank opportunism. With this one exception, PG&E opposed the use of 2005 data to forecast expenses in 2007. The only reason that TURN can discern for PG&E's use of 2005 data here, but nowhere else, is that the 2005 expenses for outside counsel costs are higher than 2004 and thus more to PG&E's liking.

TURN maintains that the 2005 data used by PG&E is flawed because it includes costs for Department of Energy (DOE) litigation on nuclear waste. When asked to describe the status of the litigation, PG&E claimed the associated costs are being tracked in a balancing account and will be netted against litigation proceeds. TURN argues that PG&E is attempting to double recover DOE litigation costs - once through the balancing account and again in this GRC.

PG&E responds that because the Settlement provides \$34.0 million less than PG&E requested for A&G expenses in 2007, it is logical to assume that the Settlement provides PG&E with less than it requested for outside legal costs. PG&E states that TURN has not shown this outcome is unreasonable. PG&E also states that TURN's point about DOE litigation expenses is off the mark because PG&E did not request recovery of any DOE-related litigation costs in this GRC.

(2) Discussion

We conclude that the Settlement outcome for outside legal expenses is reasonable in light of the record. Although we would have preferred if the Settling Parties had used only 2004 base-year data to forecast outside legal costs in 2005, the fact that 2005 recorded data appears to have been used, at least in part, does not render the Settlement outcome unreasonable. TURN alleges that the 2005 data include costs for DOE litigation that PG&E is recovering elsewhere.

PG&E denies the allegation.¹⁵⁰ TURN did not substantiate its allegation with accounting records or other dispositive facts.

On a related matter, we note that in October 2006, PG&E was awarded \$42.8 million in damages from the federal government because of the DOE's failure to build a repository for radioactive waste from nuclear power plants. PG&E began remitting waste-storage payments to the federal government in 1985. The total amount paid through December 2004 was \$299 million. The Settlement Agreement does not address this matter.

We presume the \$42.8 million damage award will be flowed through to PG&E's ratepayers in accordance with the procedures applicable to PG&E's DOE Litigation Balancing Account. Under these procedures, PG&E is required to file an application regarding the disposition of the damage award and to flow through the award, net of associated costs, in its next GRC.

(C) Public Policy and Government Affairs

(1) Position of the Parties

PG&E requested \$30.5 million for the PP&GA department in 2007, an increase of 35% over 2004 expenses. TURN recommends that funding for the PP&GA department in 2007 be limited the department's recorded costs in 2004, plus 4.5%. TURN's proposal is \$7.7 million less than PG&E's requested funding.

TURN's main concern is that it believes much of the department's expenses are for below-the-line activities, such as lobbying government officials. Although the Settlement requires PG&E to implement an improved system for tracking the time spent by employees on below-the-line activities, TURN

¹⁵⁰ Exhibit TURN 47, Answer 3A, last sentence; Settling Parties' Reply Comments filed October 5, 2006, p. 65.

contends the tracking system will do little to prevent ratepayer funding of below-the-line activities. TURN argues that the best way to protect ratepayers is to implement TURN's proposed disallowance of \$7.7 million.

TURN offers several reasons why its proposed disallowance is reasonable. First, PG&E's requested funding for the PP&GA department in 2007 is 35% higher than the department's costs in 2004. TURN states that the 35% increase is seven times inflation and customer growth, which is unreasonable on its face.

Second, TURN contends that PG&E's requested funding includes an unwarranted increase for regulatory costs. For example, PG&E's request includes \$1.126 million for contracts by the Operations Revenue Requirements organization, even though PG&E spent less than half this amount in 2005.

Third, TURN believes it is unfair for ratepayers to provide a substantial increase in funding for the PP&GA department because doing so will strengthen PG&E's ability to obtain rate increases through the regulatory process.

Fourth, PG&E's request includes a 20% increase for the Area Public Affairs (APA) organization, which is responsible for opposing municipalization proposals. TURN asserts that the requested increase for the APA organization is not justified because PG&E has understated the portion of the organization's work that is devoted to below-the-line activities.

Fifth, PG&E justifies its request for significantly higher funding based, in part, on the need for more staff to oversee an increase in contracts related to political spending in recent years while also maintaining that the amount of staff time devoted to political work is expected to decrease due to the absence of major election campaigns. TURN submits that the internal contradictions of PG&E's position undermine its request for significantly higher spending.

Finally, PG&E's request includes an increase of 182% for internal communications expenses. TURN believes that such a large increase is patently unreasonable. TURN asserts that the requested increase is due to poor management that resulted in a meltdown of the internal communications organization, resulting in the departure of key staff and the use of expensive contractors. TURN believes these facts show that PG&E needs cost discipline.

PG&E responds that TURN's proposal to limit funding growth for the PP&GA department in 2007 to a 4.5% increase over 2004 is arbitrary and ignores the projected workload and costs for the department in 2007.

(2) Discussion

The Settling Parties agree that PG&E's total 2007 A&G expenses should be \$709.4 million. This outcome is \$32.8 million less than PG&E's request of \$742.2 million.¹⁵¹ The Settlement outcome reflects the Settling Parties' resolution of all issues raised by TURN, including TURN's proposed disallowance of \$7.7 million for PP&GA department costs.

We presume that the Settlement outcome reflects some, but not all, of TURN's proposed disallowance of PP&GA department costs. To determine if this is a reasonable outcome, it is necessary to assess whether the record supports the adoption of TURN's entire disallowance. If the answer is in the affirmative, then this would be one indication that the Settlement is not reasonable in light of the whole record. Conversely, if we find that some or all of TURN's disallowance should not be adopted, then this would lend weight to the conclusion that that Settlement is reasonable in light of the whole record.

¹⁵¹ Settlement Agreement, Appendix A, Line 16.

TURN recommended an increase of 4.5% PP&GA department expenses in 2007 compared to 2004, which represents the approximate customer growth from 2004 to 2007.¹⁵² TURN's proposal ignores inflation and other cost drivers, and assumes that expenses for the PP&GA department are strictly correlated with customer growth. TURN provided no evidence to support this assumption. In contrast, PG&E provided testimony showing that the drivers of cost growth for the PP&GA department are increases in work load that are not materially related to customer growth.¹⁵³ Based on PG&E's testimony, we conclude that an increase of greater than 4.5% is warranted for the PP&GA department.

TURN offers several reasons why its proposed disallowance of \$7.7 million is reasonable. We find that TURN has demonstrated that some disallowance of PP&GA costs is justified, and this is reflected in the Settlement Agreement for the previously stated reasons. However, we also find that PG&E has justified the bulk of its requested funding for the PP&GA department.

For the preceding reasons, we conclude that the Settlement Agreement outcome with respect to PG&E's PP&GA department is reasonable in light of the whole record, consistent with the law, and in the public interest.

(D) Membership Dues and Political Contributions

(1) Position of the Parties

PG&E requested recovery of membership dues for organizations that engage in political activities. TURN asked the Commission to disallow these costs. The Settlement Motion stipulates that the resolution of TURN's

¹⁵² Exhibit TURN-1, p. 57.

¹⁵³ Exhibit PG&E-6, Chapter 14; and Exhibit PG&E-18, Chapter 47.

recommended disallowance is subsumed within the Settlement's overall outcome for A&G expenses, O&M expenses, and rate base.

TURN observes that long-standing Commission precedent requires that political donations be funded by shareholders, not ratepayers. TURN argues that the Settlement Agreement fails to adhere to this precedent by not explicitly adopting the disallowances proposed by TURN for the following dues and contributions paid to organization that engage in political activities :

Organization	Disallowance
Local Chambers of Commerce	\$26,000
California Business Roundtable (CBR)	\$25,000
Calif. Commission for Jobs & Economic Growth (CCJEG)	\$50,000
BIPAC	\$6,000
Civil Justice Assoc. of Calif.	\$29,657
Total	\$136,657

The Settling Parties oppose any modification of the Settlement Agreement. They state that TURN's recommended disallowances are already reflected in the Settlement outcome for A&G expenses, O&M expenses, and rate base.

PG&E addresses each of TURN's proposed disallowances. PG&E agrees with TURN that membership dues for local Chambers of Commerce should be borne by shareholders. However, PG&E disagrees with TURN's proposed disallowance of \$26,000. PG&E represents that it never requested \$11,000 of this amount, and that the remaining \$15,000 is part of the overall Settlement.

PG&E opposes TURN's request to disallow \$25,000 paid to the CBR and \$50,000 paid to the CCJEG. Again, the resolution of these disallowances is part of the overall Settlement. Moreover, PG&E claims that these organizations do

more than lobbying and provide customer benefits. As such, PG&E believes it is proper to charge ratepayers for the membership dues for these organizations.

PG&E represents that TURN's proposed disallowance of \$6,000 for PG&E's contributions to BIPAC is moot because PG&E withdrew its request for BIPAC funding in its rebuttal testimony.

Finally, PG&E opposes TURN's disallowance of \$29,657 contributed to the Civil Justice Association of California. PG&E contends that reasonable parties may differ on whether this amount should be the responsibility of ratepayers or shareholders. PG&E opines that the test is not whether the Settlement adopts or rejects any particular position, but whether the Settlement generally balances the various interests at stake and is consistent with policy objectives and the law.

(2) Discussion

Long-standing Commission policy prohibits rate recovery of any costs for political lobbying or advocacy. This policy is reflected in numerous Commission decisions¹⁵⁴ and underlies the purpose of the below-the-line Account 426.4.¹⁵⁵ We find that TURN's proposed disallowances fall into this category.

¹⁵⁴ See, for example, D.96-01-011, 1996 Cal. PUC LEXIS 26, *14, and D.89-12-057, 1989 Cal. PUC LEXIS 687, *36.

¹⁵⁵ FERC Account 426.4 defines lobbying activities that should not be funded by ratepayers as follows: "This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."

The Settlement Agreement would be inconsistent with the law and contrary to the public interest if it allowed into rates any of the costs that TURN seeks to disallow. PG&E has provided persuasive testimony that it has not sought, and the Settlement does not provide, rate recovery for some of TURN's proposed disallowances (i.e., \$11,000 for Chamber of Commerce membership dues and \$6,000 for BIPAC membership dues).¹⁵⁶

The Settlement's treatment of the remainder of TURN's proposed disallowance totaling \$120,657 is somewhat ambiguous. The Settling Parties do not state that TURN's proposed disallowances are adopted, only that the resolution of the issues raised by TURN are subsumed within the overall Settlement outcome. Fortunately, the amount at issue borders on being *de minimis*, and we may safely assume that all of TURN's remaining disallowance of \$120,657 is reflected in the Settlement Agreement.

We will adopt the Settlement Agreement with the understanding that it does not provide any funding for political activities. Henceforth, PG&E shall identify and track all expenditures for membership dues in organizations that engage in political activities, including all the organizations identified by TURN in this proceeding, and record an appropriate proportion of these expenditures in the below-the-line Account 426.4.

b. Holding Company Costs

i. Issued Raised by DRA

PG&E's parent company, PG&E Corporation (the Holding Company), provides support services to PG&E. PG&E requested \$65.96 million for these

¹⁵⁶ Exhibit PG&E-18, pp. 34-15 and 34-16; and Exhibit PG&E-18, pp. 46-28 to 46-29.

services in 2007, which represents 94% of the Holding Company's above-the-line costs. DRA recommended \$32.42 million, for a difference of \$33.54 million.

DRA's recommendation was based on an extensive review of Holding Company costs allocated to PG&E. DRA analyzed each category costs allocated to PG&E to determine the extent the Holding Company and PG&E each benefited from these costs. DRA then divided each category of costs between the Holding Company and the Utility based on their relative share of the benefits. Based on its analysis, DRA concluded that 49% of the Holding Company's costs should be allocated to PG&E.

PG&E responded that its request excluded all incremental costs for activities at the Holding Company that either (1) provide no demonstrable benefit to PG&E, or (2) if performed by PG&E, could be performed more efficiently or at a lower overall cost.

The Settling Parties agree that the resolution of the issues raised by DRA regarding Holding Company costs is subsumed within the Settlement outcome for A&G expenses. The Settlement provides PG&E with \$709.4 million for A&G expenses in 2007, which is \$32.8 million less than PG&E requested.¹⁵⁷

We commend DRA for its thorough analysis of Holding Company costs allocated to PG&E. Absent the Settlement Agreement, we would have adopted some, but not all, of DRA's proposed disallowance of these costs.

We assume the Settlement outcome reflects DRA's litigation position on Holding Company costs by providing PG&E with less money for A&G expenses than it requested. With this assumption in mind, we find the Settlement outcome

¹⁵⁷ Settlement Motion, p. 108.

for the Holding Company issues raised by DRA is reasonable in light of the record, consistent with applicable law, and in the public interest.

ii. Issues Raised by TURN

TURN challenges PG&E's requested revenue requirement for the Holding Company's SVP of the PP&GA department. PG&E requested \$0.619 million for this department in 2007.¹⁵⁸

TURN argues that this department's costs should be frozen at the 2004 level of \$0.420 million. PG&E responds that TURN's proposal is based on its mistaken belief that the department's costs increased from 2004 (\$0.420 million) to 2007 (\$0.530 million). However, PG&E's errata corrected the 2004 recorded amount for this department from \$0.420 million to \$0.702 million.¹⁵⁹ Therefore, PG&E's 2007 test-year request (\$0.619 million) is less than this department's costs in 2004 (\$0.720 million). PG&E believes this issue is now moot.

We find that the record shows that PG&E's requested expenses for the PP&GA department in 2007 are less than the department's actual costs in 2004. Therefore, we agree with PG&E that this issue is moot.

c. Employee Compensation

i. Total Compensation

DRA and PG&E jointly selected Towers Perrin to conduct the Total Compensation Study (Compensation Study). The purpose of the Compensation Study was to compare the total compensation paid to PG&E's employees (i.e., base pay, bonuses, and employee benefits) to the labor market represented by a

¹⁵⁸ PG&E allocated 47% of this department's total costs below-the-line because they relate to political contributions.

¹⁵⁹ Exhibit PG&E-16, p. 16-205; Exhibit PG&E-18, p. 46-24 to p. 46-26.

survey of selected industrial and utility companies. The Compensation Study revealed that PG&E's total compensation is 4.71% above the survey average. Towers Perrin considers +/- 10% of the market average to be the range of competitiveness. Since PG&E's total compensation falls within this range, the Compensation Study indicates that PG&E's total compensation is reasonable.

No party disputed the reasonableness of PG&E's total compensation. However, DRA contested one element of PG&E's compensation. The parties' litigation positions on this issues are summarized below.

(A) Employee Incentive Plan

PG&E employees are eligible for annual bonuses under the Performance Incentive Plan (PIP). The Total Compensation Study included the actual PIP payments made in 2004. PG&E requested \$56.2 million for PIP payments in 2007, equivalent to 50% of the maximum potential payout and below the historical average. Shareholders would bear the cost of PIP payments over 50%.

PG&E Corporation's Short-term Incentive Plan (STIP) is similar to PG&E's PIP. PG&E requested \$5.1 million in 2007 for STIP expenses, equivalent to 50% of the maximum potential payout.

DRA recommended that the Commission disallow half of PG&E's request for PIP, or \$28.1 million. DRA contended that PG&E's PIP payout percentage has increased significantly since 2000, and that ratepayers should not have to pay for the increase. DRA also argued that shareholders benefit from PIP costs and, therefore, should share the forecasted costs.

DRA argued that because STIP costs are incurred at the Holding Company level, these costs should first be disallowed in the same proportion as DRA's proposed disallowance of other Holding Company costs, and then reduced another 50% consistent with DRA's PIP recommendations.

PG&E responded that the requested PIP expenses are reasonable because total compensation, of which PIP is a component, is reasonable. Further, when a utility provides safe and reliable service and earns its authorized rate of return, as reflected in the PIP award, both customers and shareholders benefit and the Commission cannot realistically allocate between these two groups the reasonable PIP costs to achieve these twin goals. PG&E also contended that its request is supported by the Commission's decision in SCE's recent GRC. There, the Commission granted full recovery of incentive pay based on actual costs.¹⁶⁰ Here, PG&E has requested recovery of target costs (50% of maximum potential payout), which is lower than PG&E's historical percentage payout.

PG&E opposed DRA's proposed disallowance of STIP costs for the same reasons it opposed DRA's recommendation for PIP.

The Settling Parties agree that issues regarding total compensation, PIP, and STIP are subsumed in the Settlement outcome for A&G expenses. The Settlement provides PG&E with \$709.4 million in A&G expenses in 2007, which is \$32.8 million less than PG&E requested.¹⁶¹ No party contested this aspect of the Settlement Agreement.

(B) Discussion

We find that the uncontested Settlement outcome for total compensation, PIP, and STIP is reasonable in light of the record, consistent with applicable law, and in the public interest.

¹⁶⁰ D.06-05-016, *mimeo.*, p. 129.

¹⁶¹ Settlement Motion, p. 108.

ii. Pensions and Benefits

PG&E's employee compensation includes the following benefits:

(1) pension benefits, (2) various medical benefits, (3) post-retirement benefits other than pensions (PBOPs), (4) group life insurance, (5) flexible benefit program, (6) long-term disability (LTD), (7) retirement savings plan, (8) tuition refund, (9) relocation expenses, and (10) service awards.

PG&E requested \$768.98 million for benefits expenses in 2007 for the entire Company, before capitalized and other allocated amounts are removed. DRA, Aglet, and TURN raised several issues regarding PG&E's requested benefits expenses. Below, we assess the reasonableness of the Settlement outcome on benefits expenses in light of the record on the major categories of benefits expenses and the issues raised by the parties.

(A) Pension Contributions

In D.06-06-014, which was issued earlier in this proceeding, the Commission adopted an uncontested settlement agreement that authorizes PG&E to (1) contribute \$249.7 million to its Pension trust in 2006 and \$153.4 million annually in 2007-2009, and (2) recover the following revenue requirement for its GRC lines of business during 2006-2009:

\$ Millions				
<i>GRC Line of Business</i>	2006	2007	2008	2009
Electric Distribution	77.2	46.8	48.4	50.5
Gas Distribution	34.5	26.2	27.2	28.3
Electric Generation	43.3	25.3	26.2	27.3
GRC Total	155.0	98.2	101.7	106.1
Source: D.06-06-014, <i>mimeo.</i> , p. 2.				

PG&E is authorized by D.06-06-014 to recover the revenue requirement shown in the above table for the pension contributions in 2007-2009 in the base rates authorized by today's Opinion.¹⁶² The contributions authorized by D.06-06-014 are projected to result in a fully funded pension plan by January 1, 2010.¹⁶³

D.06-06-014 resolved all issues concerning PG&E's pension costs for the years 2007-2009. However, because the Settlement extends the GRC cycle through the year 2010, the Settling Parties agree that pension-contribution settlement approved by D.06-06-014 for the years 2007-2009 should be extended through 2010. The relevant provisions are in paragraphs 37-39 of the Settlement Agreement and include the following:

1. PG&E will make a total pension contribution of \$176.0 million for the year 2010, which equates to a net contribution of \$153.4 million. (D.06-06-014, FOF 10 and OP 5.)
2. PG&E will recover in base rates the revenue requirement for the portion of the pension contribution authorized for 2010 that is allocable to PG&E's GRC lines of business. Recovery of the pension-contribution revenue requirement for non-GRC lines of business will be authorized, as appropriate, in other proceedings and venues. (D.06-06-014, OP 6.)
3. The advice letter required by OP 7 of D.06-06-014 will extend through the year 2010.
4. The annual report required by OP 8 of D.06-06-014 will continue through the year 2011.

¹⁶² The revenue requirement is less than the contributions because a portion of the contributions is capitalized and recovered over time through depreciation expense.

¹⁶³ D.06-06-014, *mimeo.*, pp. 9 -10.

The revenue requirement for pension costs adopted in D.06-06-014 and the Settlement Agreement is in addition to the GRC revenue requirement adopted by the Settlement. The cumulative increase in GRC revenues (other than pension costs) adopted by the Settlement is \$1.637 billion through 2010.¹⁶⁴ The cumulative increase in revenues for pension costs is \$417 million through 2010.¹⁶⁵

There is no opposition to the Settlement outcome for pensions costs. We find the Settlement outcome on this matter is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

(B) Issues Raised by DRA

(1) Medical Escalation Rates

PG&E requested \$217.8 million for medical benefit expenses in 2007. DRA recommended \$195.6 million. PG&E forecasted medical benefit costs in 2007 by escalating 2004 recorded costs by medical-trend factors less savings from plan changes. PG&E based its trend factors on (1) claims and enrollment information, (2) national trend data, and (3) Global Insight's forecast of the Employment Cost Index for Health Insurance (ECIHI).¹⁶⁶

DRA forecasted medical benefit costs in 2007 by escalating 2004 recorded costs by Global Insight's projection of the ECIHI. Aglet agreed with DRA.

¹⁶⁴ \$1.637 billion = \$852 million for 2007 (i.e., \$213 million x 4) + \$375 million for 2008 (i.e., \$125 million x 3) + \$250 million for 2009 (i.e., \$125 million x 2) + \$125 million for 2010, + \$35 million for the Diablo Canyon refueling outage in 2009 or 2010.

¹⁶⁵ \$417 million = \$98 million (2007) + \$102 million (2008) + \$106 million (2009) + \$111 million (2010). The amounts for 2007-2009 are from D.06-06-014, *mimeo.*, p. 2. The amount for 2010 is estimated.

¹⁶⁶ Global Insight is a private company that provides econometric forecasts that are used regularly in Commission proceedings.

PG&E responded that the ECIHI does not accurately track PG&E's medical benefits costs. PG&E also asserted that Global Insight's previous forecasts of the ECIHI have been (1) lower than PG&E's medical trend experience, and (2) lower than the actual ECIHI, as reported by the Bureau of Labor Statistics.

(2) Service Award Program

PG&E's Service Award Program provides each employee with a "thank you" gift at every five-year anniversary and at retirement. PG&E requested \$1.1 million for this program in 2007.

DRA argued that several Commission decisions have denied ratepayer funding for awards that fit into the category of social activities, and that PG&E's Service Award Program should be disallowed on the same basis.

PG&E responded that its Service Awards are not social activities, but tangible tokens of appreciation for continuous employee service. Moreover, the Service Awards Program is part of PG&E's total compensation package -- a package that is within the range of market compensation.

(3) Relocation Benefits

PG&E provides relocation benefits to assist employees with costs associated with Company-initiated moves. PG&E requested \$2.61 million for relocation expenses for PG&E employees in 2007 and \$0.7 million for Holding Company employees. DRA concurred with PG&E's request for its own employees, but recommended that PG&E's request for Holding Company employees be reduced by 50%. PG&E opposed DRA's proposed reduction.

(4) PBOP Medical and Disability Benefits

PG&E requested \$58.2 million in 2007 for contributions to a Voluntary Employee Benefits Association (VEBA) trust to fund PG&E's retirement medical plan. PG&E's request was based on the lower of (1) PBOP's expense determined

in accordance with Statement of Financial Accounting Standard (SFAS) No. 106, or (2) tax-deductible limits on VEBA contributions.

PG&E also requested \$66.1 million in 2007 for tax-deductible contributions to its LTD VEBA trust to fund (1) pay-as-you-go costs for current disabled employees, (2) the increase in the actuarial accrued liability, and (3) amortization of the unfunded accrued liability.

DRA concurred. No other party addressed this matter.

(5) The Settlement Agreement

The Settling Parties agree that the resolution of issues regarding medical escalation rates, Service Awards, allocation of Holding Company benefits costs to PG&E, and funding of PBOP and disability contributions is subsumed in the Settlement outcome for all A&G expenses. The Settlement Agreement provides PG&E with \$709.4 million for A&G expenses in 2007, which is \$32.8 million less than PG&E requested and \$66.5 million more than DRA recommended.

The Settlement Agreement also requires PG&E to contribute 124.3 million annually to its PBOP VEBA trusts during 2007 - 2010. As required by D.92-12-015 and D.95-12-055, the Settlement provides that PG&E will file at the end of the 2007 GRC cycle a consolidated true-up of the actual contributions to the PBOP VEBA trusts with the revenue requirement collected in rates.¹⁶⁷

There was no opposition to the Settlement outcome for benefits costs.

(6) Discussion

We find the uncontested Settlement outcome for benefits costs is reasonable in light of the record, consistent with applicable law, and in the public

¹⁶⁷ Settlement Motion, p. 184, and Settlement Agreement, para. 32.

interest. Our finding includes one caveat. Specifically, to ensure there is no misunderstanding of PG&E's obligation under the Settlement Agreement to contribute \$124.3 million annually to its PBOP trusts, we remind PG&E that Ordering Paragraph 2 of D.92-12-015 requires any funds collected in rates for contributions to PBOP trusts to be used for that purpose or returned to ratepayers.¹⁶⁸ The report that PG&E is required to submit pursuant to the Settlement Agreement in 2010 regarding its PBOP contributions¹⁶⁹ shall state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.

(C) Aglet's Comparison of Utility Medical Costs

(1) Position of the Parties

Aglet is concerned that PG&E's employee medical expenses appear to be high compared to SCE's. The following table compares PG&E's and SCE's medical costs per employee in nominal dollars:

<u>Year</u>	<u>PG&E</u>	<u>Increase</u>	<u>SCE</u>	<u>Increase</u>
2004	\$7,553	--	\$5,317	14.0%
2005	\$8,666	14.7%	\$5,849	10.0%
2006	\$9,060	4.5%	\$5,849	0.0%
2007	\$9,957	9.9%	--	--

The above comparison leads Aglet to recommend that the Commission order PG&E to provide in its next GRC proceeding a report that (1) compares

¹⁶⁸ D.92-12-015, 46 CPUC 2d 499, 532. See also D.95-12-055, 63 CPUC 2d 570, 593-94, and D.00-02-046, 4 CPUC 3d 315, 463.

¹⁶⁹ Settlement Agreement, para. 32.

PG&E's unit medical benefit costs with similar costs for SCE, SDG&E, and SCG; (2) analyzes differences between PG&E's costs and similar costs for the same utilities; and (3) describes the status of negotiations with both represented and non-represented employees regarding future medical benefits.

PG&E opposes Aglet's recommendation. PG&E responds that the above table is misleading because it is limited to active employees and ignores retirees. PG&E's average medical cost for both active and retired employees was approximately \$7,000 per participant in 2006, which was lower than SCE's average of more than \$8,000.

PG&E also argues that Aglet's proposed report is unnecessary because PG&E already submits in GRC proceedings a Total Compensation Study that compares the total compensation paid to PG&E's employees (including medical benefits) to the total compensation paid by similar employers. PG&E states that the Total Compensation Study uses a fair methodology to compare employee benefits that minimizes the effects of employer differences in demographics, regional pricing differences, and plan utilization, which facilitates accurate comparison of benefit plans across employers.

(2) Discussion

Aglet has demonstrated that PG&E's medical benefit costs for active employees are significantly higher than SCE's. Still, PG&E's overall compensation, including medical benefit costs, is within the range of competitiveness, as discussed above. We agree with Aglet that it would be useful for PG&E to explain the reasons for its higher medical costs in the next GRC. But we will not require the specific reporting requirements recommended by Aglet.

(D) TURN's Linkage of P&B Costs to Payroll

(1) Position of the Parties

PG&E's forecast of pension and benefit (P&B) expenses in 2007 was based on 2004 recorded expenses updated to reflect cost trends and expected plan changes. The Settlement Agreement adopts PG&E's methodology.

TURN observes that PG&E did not forecast its P&B costs based on the number of employees it would have in 2007. Consequently, if employee numbers (and labor costs) change as a result of recommendations made by TURN or others, there will be no corresponding change to PG&E's P&B costs.

TURN believes it is unreasonable to assume that P&B costs will remain unchanged if there is a disallowance of employee labor costs. According to TURN, any disallowance of labor costs should translate into fewer employees and lower P&B costs. Therefore, if there is a disallowance of labor costs, TURN recommends that there also be a proportional disallowance of P&B costs.

PG&E responded that it would manage any disallowance of labor costs by reducing overtime and/or hiring-hall labor which have no associated P&B costs.

(2) Discussion

We decline to adopt TURN's recommendation to reduce PG&E's P&B costs in proportion to any disallowance of labor expenses. PG&E testified that if it needs to lower labor expenses, it intends to do so by reducing overtime and hiring-hall labor. PG&E further testified that (1) PG&E employees working overtime do not receive additional pensions and benefits, and (2) hiring-hall workers are not PG&E employees and do not participate in PG&E's P&B plans. Therefore, any reduction of overtime and hiring-hall labor would not affect

PG&E's P&B costs.¹⁷⁰ Thus, it is inappropriate to reduce P&B costs in proportion to disallowed labor expenses as TURN proposes.

We recognize that overtime and hiring-hall labor represent only a small portion of PG&E's labor costs. If the Commission were to disallow a significant amount of labor costs, it is likely that PG&E would have to reduce its workforce. It would probably make sense in that situation to reduce the P&B costs associated with the reduction in PG&E's workforce. However, because today's Opinion does not adopt a major reduction to labor costs, it is unnecessary to consider partial implementation of TURN's recommendation.

d. Other A&G Expenses

PG&E's request for Other A&G expenses in 2007 had four components. First, PG&E requested \$82.5 million for Account 925 expenses. These expenses include workers' compensation, settlements and judgments, and certain insurance costs. No party objected to the request.

Second, PG&E requested \$1.2 million for severance benefits. DRA argued that PG&E had not justified the need for this program. PG&E responded that the program benefits ratepayers by facilitating organizational restructurings that enhance operational effectiveness, and that the Commission has previously authorized funding for severance benefits.

Third, PG&E requested \$27.4 million for property insurance, directors and officers liability insurance, and general liability insurance. No party objected.

Finally, PG&E requested \$82 million for Miscellaneous A&G Costs, which included \$78.9 million for so-called "non-study departments" (NSDs). The NSDs

¹⁷⁰ Exhibit PG&E-18, p. 1-5, L: 20-26.

include ISTS and Corporate Real Estate (CRE). DRA proposed disallowances totaling \$68.7 million for ISTS and CRE, which are addressed, *infra*.

The Settling Parties agree that the resolution of issues concerning Other A&G expenses is subsumed in the Settlement outcome for all A&G expenses. The Settlement provides \$709.4 million for GRC-related A&G expenses in 2007, which is \$32.7 million less than PG&E requested \$66.5 million more than DRA recommended.¹⁷¹ There is no opposition to the Settlement on this matter.

We find the uncontested Settlement outcome for Other A&G expenses, including the outcome for ISTS and CRE expenses that is addressed, *infra*, is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

e. Unbundling

The term “unbundling” refers to the process of separating PG&E’s costs into major lines-of-business called Unbundled Cost Categories (UCCs). By separating costs into UCCs, the Commission can better match the cost-of-service with the customers who receive those services. The unbundling process includes the allocation of common costs such as A&G expenses, which are not directly assignable to a particular UCC.

DRA agreed with PG&E’s list of UCCs and methodology for unbundling common costs, which is reflected in the Settlement Agreement. There is no opposition to this aspect of the Settlement.

We find the uncontested Settlement outcome on unbundling to be reasonable in light of the record and consistent with Commission precedent.

¹⁷¹ Settlement Agreement, Appendix A, Line 16.

f. Conclusion re: A&G Expenses

For the preceding reasons, we conclude that the Settlement Agreement provisions regarding A&G expenses are reasonable in light of the record, consistent with the law, and in the public interest, and should be adopted.

3. General Services and Other Support Costs

PG&E's General Services organizations provide services to PG&E as a whole. These services include transportation, materials handling, building services, and the Company airplane. Most expenses incurred by the General Services organizations are direct-charged to the organizations that use the services and are included in PG&E's requests for the user departments.

a. Areas of Agreement

There was no opposition to PG&E's requested expenses and capital expenditures in the following categories of General Services:

Areas of Agreement re: 2007 General Services Expenses and Capital Expenditures		
Area	Requested Expenses (millions)	Requested Cap. Ex. (millions)
Utility Support Operations	\$7.0	\$1.3
Materials Operations	- -	\$34.1
Purchasing Operations	\$0.1	\$1.3
Total	\$7.1	\$36.70

The Settling Parties agree that (1) expenses for the above categories of General Services are subsumed within the Settlement outcomes for A&G and O&M expenses, and (2) capital expenditures for the above categories of General Services are subsumed within the overall Settlement outcomes capital additions

and rate base.¹⁷² There was no opposition to the Settlement outcomes for the above categories of General Services.

Based on our review of the record, we find the uncontested Settlement outcome for Utility Operations Support, Materials Operations, and Purchasing Operations is reasonable in light of the record, consistent with the law, and in the public interest.

b. Issues Raised by the Parties

DRA, Aglet, and TURN opposed several facets of PG&E's requested expenses and capital expenditures for General Services. Below, we assess the reasonableness of the Settlement outcome for General Services in light of the record on the issues raised by the parties.

i. Transportation Services Capital Expenditures

PG&E operates a transportation fleet of approximately 11,937 cars, trucks, power-operated equipment, off-road equipment, and trailers. PG&E has 64 service facilities to maintain and repair its fleet.

PG&E requested \$150.2 million for capital expenditures in 2007 to replace worn-out fleet equipment, comply with environmental mandates, and to manage, repair, and maintain fleet assets.¹⁷³ PG&E also requested \$0.961 million for tools. DRA recommended \$72.9 million for fleet replacement and \$0.519 million for tools. TURN also had one recommendation.

The litigation positions of the parties are summarized below.

¹⁷² Settlement Motion, p. 188.

¹⁷³ The 2007 amount requested by PG&E reflects a reduction in capital expenditures of \$15.8 million during 2006-2009 that was proposed by TURN and accepted by PG&E.

(A) Equipment Replacement

DRA proposed two reductions to PG&E's requested capital expenditures in 2007 to purchase transportation vehicles and equipment. First, DRA recommended a reduction of \$24 million to replace long-term rentals with PG&E-owned equipment. Both parties agreed on the need to replace long-term rentals, but DRA proposed that this be accomplished over three years, whereas PG&E proposed that all rentals be replaced in 2007.

Second, DRA proposed a reduction of \$52.3 million based on historical capital expenditures. PG&E responded that historical spending had resulted in an aging fleet that is increasingly costly to maintain. Continued spending at historical levels would result in an even older fleet.

PG&E presented evidence that showed existing assets are getting older, and almost 30% are failing before being replaced. PG&E contended that it was unreasonable to expect employees to operate equipment past its life cycle or to expect customers to accept delays in service because of unreliable equipment.

(B) EPA Compliance

DRA disagreed with two elements of PG&E's request for capital expenditures to comply with the federal Environmental Protection Act (EPA). First, DRA proposed a disallowance of \$6.5 million based on its concern that \$6.5 million was being double counted. PG&E demonstrated in Exhibit PG&E-43 that the double counting error was \$1.275 million, not \$6.5 million. PG&E and DRA subsequently agreed to an adjustment of \$1.275 million.

Second, DRA proposed a disallowance of \$2.045 million for the purchase of green-fuel vehicles over 8,500 lb. gross vehicle weight. DRA's proposal was based on its reading of a PG&E data response, which DRA interpreted as indicating that PG&E might not purchase the vehicles. PG&E responded that

DRA's interpretation was incorrect; PG&E's data response had nothing to do with whether PG&E would purchase the vehicles, but whether the vehicles that PG&E purchased would qualify for a tax credit.

(C) Capital Tools

DRA proposed that PG&E's requested capital expenditures for tools in 2007 be reduced from \$0.961 million to \$0.519 million. DRA based its proposal on a four-year average of historical spending. PG&E responded that historical spending should not be used as the basis for future expenditures because of changed circumstances.

For example, in 2004 the Corporate Real Estate (CRE) department was responsible for fuel islands, fuel dispensers, wash racks, garage doors, and recycling systems. Responsibility for these items was transferred to Transportation Services in 2005. As a result, PG&E's requested capital expenditures for tools for CRE decreased significantly, but increased significantly for Transportation Services. PG&E argued that it was unfair to accept the CRE decrease without a corresponding increase for Transportation Services.

PG&E also contended that DRA's proposal should be adjusted to include \$0.115 million to replace PG&E's TRAC fuel system, which was installed in the 1980's and was not captured in the 4-year historical average used by DRA.

(D) Issues Raised By TURN

TURN recommended that PG&E's rate base be reduced by \$37.5 million due to improper accounting for rental savings. TURN argued that fleet rental costs were outside the Results of Operations (RO) model, and that ratepayers would pay the capital costs to replace rentals but would not receive the savings from reduced rental payments. PG&E agreed that customers should benefit from

reduced rental costs, and PG&E represents that it incorporated the projected savings into the Comparison Exhibit.

(E) The Settlement Agreement

The Settling Parties agree that the resolution of issues concerning Transportation Services capital expenditures is subsumed within the Settlement outcomes for capital additions and rate base.¹⁷⁴ There is no opposition to this aspect of the Settlement Agreement.

(F) Discussion

PG&E's Transportation Services organization is essential to PG&E's ability to provide utility services to the public. No party contests the Settlement provisions pertaining to Transpiration Services, and no party alleges that these provisions violate any law or regulation. To the contrary, the record shows that Settlement provides funding for PG&E's transportation fleet and operations to comply with applicable environmental laws and regulations.

For the preceding reasons, we conclude that the Settlement outcome for Transpirations Services is reasonable in light of the record, consistent with the law, and in the public interest.

ii. Company Airplane

(A) Position of the Parties

(1) The Settlement Agreement

PG&E requested \$18 million to replace its Company airplane, a Fairchild-Dornier 328 turbo-prop that PG&E purchased new in 1994. The existing airplane carries 350 to 400 employees monthly, primarily between Oakland and San Luis

¹⁷⁴ Settlement Motion, p. 188.

Obispo. The plane flew 559 hours in 2004 and 492 hours in 2005. PG&E expects increased usage of the Company plane due to major capital projects that are currently underway at the Diablo Canyon and Humboldt Bay power plants.

PG&E testified that the Company airplane increases employee productivity by limiting the hours spent traveling to and from job sites. Owning an airplane also provides PG&E with complete control over critical safety and reliability issues, such as pilot quality and training, aircraft maintenance, passenger and baggage manifests, and operational safety standards.

PG&E is concerned about the safety and reliability of the current airplane because of reduced access to spare parts and required refresher training courses for flight crews. According to PG&E, the availability of replacement parts has declined in the four years since the manufacturer declared bankruptcy. When PG&E can obtain a replacement part, it is usually a repaired unit. A repaired unit is not completely overhauled; only the broken component within the part is repaired. PG&E testified that it has received replacement parts with much higher total times on them than the part needing replacement.

PG&E performed a net present value (NPV) analysis of the alternatives for direct access to an airplane, including purchase, lease, charters, commercial airlines, and maintenance of the existing plane. Based on its analysis, PG&E concluded that the purchase of a used Embraer Legacy Shuttle is the best option. PG&E obtained price quotes in the range of \$15-21 million for a used Embraer. PG&E submits that its \$18 million request is an appropriate middle point to forecast the cost of the replacement plane.

PG&E testified that the replacement airplane, like the current plane, will be used to shuttle employees to job sites. There will be relatively little use of the plane for executive transport. PG&E also provided data showing that the

Holding Company rarely uses the existing plane. Given that PG&E will continue to be the primary user of the Company airplane, PG&E contends that it is appropriate that the cost of the replacement airplane be borne by PG&E, with appropriate charges to the Holding Company for its use of the airplane, if any.

PG&E charges for use of the Company plane. For PG&E employees and contractors, a \$400 charge is levied on the department for whom the PG&E employee or contractor works. If an elected official uses the aircraft, PG&E complies with all regulations governing services and gifts to elected officials. For other passengers, use of the plane must be approved by a Vice President and that officer's department is charged for use of the airplane. PG&E represents that it prohibits personal use of the plane.

DRA opposed PG&E's request for a replacement airplane on the grounds that PG&E had not adequately supported its request. If PG&E were allowed to acquire another airplane, DRA proposed that the cost of the plane be borne by the Holding Company, with appropriate charges to the Utility, because the Holding Company has priority use of the plane.

The Settling Parties agree that PG&E's request to acquire a replacement airplane is included in the \$81.9 million weighted-average capital additions for Generation adopted by the Settlement. The Settling Parties further agree that PG&E will review and update the charges for use of the airplane and submit a report to the Commission and DRA within 90 days of today's Opinion.¹⁷⁵

¹⁷⁵ Settlement Agreement, paras. 28 and 29.

(2) Aglet

Aglet opposes rate recovery for a replacement airplane. Aglet asserts that PG&E has not shown that it needs another plane, has not justified its estimate of the market value of the existing plane, and has not fairly allocated costs to the Holding Company, which has priority for use of the plane.

Aglet also recommends that the Commission remove from test-year expenses the majority of operating costs for a Company airplane. Aglet submits that PG&E has not justified rate recovery of expenses that benefit the Holding Company more than the Utility.

(3) TURN

TURN asserts that PG&E has not demonstrated a need for a replacement aircraft. The purported unavailability of spare parts is undermined by a newspaper article that quotes the general manager of a major aircraft servicing company as stating that the supply of spare parts is robust and that a typical Dornier 328 should have a service life of 30-40 years.

TURN criticizes PG&E's NPV analysis of acquiring a replacement plane. TURN states that PG&E did not analyze any intermediate options, such as retaining the existing plane for this GRC cycle and replacing it with a leased plane in 2010. TURN also believes that PG&E's NPV analysis is flawed because PG&E used a discount rate based on the lower, after-tax cost of capital instead of the higher, pre-tax cost of capital actually paid by ratepayers. Using an after-tax rate skews the NPV calculations in favor of ownership.

If PG&E is allowed to acquire a replacement plane, TURN recommends that PG&E lease rather than buy. TURN states that with PG&E's proposed 8-year depreciable life, owning an airplane would cost nearly \$9 million more over the GRC cycle relative to leasing. If a 13-year depreciable life is presumed

for a replacement aircraft (which mirrors the life of the current Dornier 328), ownership would cost \$6.5 million more than leasing over the 2007-2009 GRC cycle. If the Commission nonetheless allows PG&E to purchase an airplane rather than lease, TURN recommends that the Commission adopt a 13-year depreciation life for the aircraft (based on the life achieved by the current plane) rather than the 8-year life used in PG&E's analysis.

If the Commission approves either a purchase or lease, TURN asks the Commission to reduce rate base by \$2 million (by increasing accumulated depreciation) to include PG&E's estimated salvage value for the existing airplane. TURN represents that PG&E concedes that \$2 million is a reasonable estimate of the salvage value, and that PG&E confirmed that the Settlement does not incorporate this concession. TURN urges the Commission to include this concession in the final decision.

TURN recommends that PG&E implement three changes to its policies governing the Company airplane. First, PG&E must ensure that charges for use of the airplane are reasonable. PG&E has a chargeback system in place, and PG&E has agreed to review and update this system as part of the Settlement. However, TURN is concerned that this will only lead to an update of the current charge of \$400 per person, per flight. Rather than developing a generic cost estimate, TURN believes PG&E should calculate chargebacks based on the incremental cost of using the airplane for a specific trip.

Second, TURN recommends that PG&E implement a cost-containment policy for use of the plane. Currently, PG&E uses the plane when there are lower-cost alternatives. For example, PG&E's CEO used the plane when lower-cost commercial flights were readily available. TURN submits that it is not

reasonable for ratepayers to finance the preferred business travel arrangements of PG&E executives when less expensive (and suitable) alternatives exist.

Finally, TURN has uncovered problems with personal use of the Company plane. For example, PG&E's former CEO used the plane for personal travel and brought family members along. There is no evidence that PG&E was reimbursed for such usage. TURN recommends that the Commission require PG&E to establish a written policy on personal usage of the plane and to implement procedures which ensure that PG&E is compensated for any non-business use at the incremental cost of the trip (not a generic chargeback).

(B) Discussion

The Settling Parties agree that PG&E's request for \$18 million to purchase a replacement airplane is included in the Settlement's \$81.9 million weighted-average capital additions for Generation in 2007. The Settlement Agreement adopts the full amount of PG&E's request for Generation capital additions in 2007.¹⁷⁶ Based on this information, we conclude that the Settlement Agreement adopts PG&E's position on the replacement airplane.

We begin our analysis of the Settlement outcome with an assessment of PG&E's need for an airplane. PG&E testified that its plane is in the air 450 to 500 hours annually, and that the plane transports 350 to 400 employees monthly.¹⁷⁷ PG&E also testified that the plane is used primarily to shuttle employees between Company work sites, and there is very little use of the plane by the Holding Company or to transport executives to non-utility locations. According

¹⁷⁶ Settlement Agreement, Appendix G, Table 3-7, Line 32.

¹⁷⁷ Exhibit PG&E-88, p. 55-1.

to PG&E, the plane increases employee productivity by limiting the hours spent traveling hundreds of miles to and from job sites.

Based on PG&E's testimony, we conclude that PG&E has a reasonable need for an airplane. PG&E has also demonstrated that the Utility is the primary beneficiary of the airplane, even though the Holding Company uses the plane occasionally. Based on our conclusion, we deny Aglet's request to prohibit rate recovery of the majority of the expenses for an airplane.

We next consider PG&E's request to replace its existing airplane. TURN presented testimony which shows that keeping the existing aircraft has a slight cost advantage over the next 13 years compared to the acquisition of a replacement aircraft.¹⁷⁸ PG&E testified that its current plane is 13 years old and has become difficult to maintain since the manufacturer declared bankruptcy several years ago. TURN challenged PG&E's testimony with hearsay from an article in the *San Francisco Chronicle*. We accord greater weight to PG&E's sworn testimony that PG&E's existing aircraft will not adequately meet PG&E's needs because of the safety and reliability concerns caused by reduced access to quality parts and required training courses for PG&E's flight crews.¹⁷⁹ Based on the record evidence, we conclude that PG&E has demonstrated a reasonable need for a replacement aircraft. Therefore, we deny TURN's request to prohibit rate recovery of a replacement aircraft in the current GRC cycle.

PG&E and TURN presented conflicting testimony on whether it is cheaper to buy or lease a replacement airplane. PG&E performed an NPV analysis that used an after-tax weighted cost of capital and assumed that the cost of the lease

¹⁷⁸ Exhibit TURN-1, p. 13, Table 1.

¹⁷⁹ Exhibit PG&E-18, pp. 55-1 to 55-3.

must be increased by additional equity financing to offset “lease debt.”¹⁸⁰

PG&E’s analysis shows the NPV of leasing is marginally cheaper than buying.¹⁸¹

TURN used PG&E’s data and a pre-tax cost of capital. TURN’s analysis shows that leasing is cheaper than buying over a 13-year period.

We find that PG&E and TURN each presented a flawed analysis. PG&E’s analysis is flawed because it used an after-tax cost of capital, which is much lower than the pre-tax cost of capital paid by PG&E’s ratepayers. PG&E also used the inappropriate assumption that PG&E must borrow money to pay for a lease, even though the lease payments would be recovered in rates. The flaws in PG&E’s analysis increased lease costs relative to purchase costs.

TURN’s analysis is flawed in the way it set up the comparison for lease versus buy. The lease payments used by TURN assume a residual value of 60% for the leased aircraft.¹⁸² In contrast, TURN’s computation of depreciation expense under the purchase scenario assumes an aircraft salvage value of 20%. In order to have an apples-to-apples comparison of lease versus buy, it is necessary to have the same ending value for the aircraft under both the lease scenario and the purchase scenario. By using a 60% residual value for the lease scenario compared to a 20% salvage value under the purchase scenario, TURN understated the cost of leasing compared to buying. In addition, TURN included property taxes in its determination of aircraft purchase costs,¹⁸³ but TURN seems to have excluded property taxes from its determination of lease costs. TURN’s

¹⁸⁰ 33 TR 3132:1-4.

¹⁸¹ Exhibit PG&E-18, p. 55-6; Exhibit DRA-80, p. 17; and 33 TR 3129:24-28.

¹⁸² Exhibit TURN-1, Attachment 4, p. 5, and Attachment 5, p. 3.

¹⁸³ Exhibit TURN-1, Attachment 5, spreadsheets on pp. 4 and 5, Column 12.

treatment of property taxes appears to have inflated aircraft purchase costs relative to lease costs.

The information in the record is insufficient to make a precise comparison of leasing versus buying a replacement aircraft. Based on our review of the record, we conclude that the total costs to ratepayers to lease a replacement aircraft or purchase a replacement aircraft over the next 13 years will be similar, whether measured in present-value dollars or nominal dollars. For the preceding reasons, we find the Settlement Agreement's provisions that allow PG&E to purchase a replacement aircraft in 2007 for \$18 million are reasonable in light of the whole record and in the public interest.

We agree with TURN that (1) rate base should be reduced in 2007 by \$2 million for the net salvage value of the existing aircraft, and (2) the replacement aircraft should be depreciated over 13 years, which would mirror the life of PG&E's current aircraft. Based on our review of the RO model, it appears that both of TURN's recommendation are reflected in the Settlement Agreement in a round about way.¹⁸⁴

We decline to adopt TURN proposals to establish new policies and charges for the use of the Company airplane. PG&E testified that it already charges for use of the existing airplane:

¹⁸⁴ Our review of the Settlement RO model shows that \$18 million for the replacement plane is added to Diablo Canyon capital on January 1, 2007, and is depreciated at an annual rate of 3.9%. This rate reflects a service life that is much longer than TURN's proposed depreciation period of 13 years. The long service life assumed by the RO model for the replacement airplane more than offsets any cost increases that might be caused by the inclusion of zero salvage value for the current airplane in the RO model. In the next GRC, PG&E should reduce rate base by the actual salvage value on the existing airplane and present an appropriate depreciation expense for the replacement airplane based on a 13-year service life.

For PG&E employees and contractor's working directly for PG&E, a \$400 charge is made to the PCC or order number of the department for whom the PG&E employee or contractor works. If an elected official uses the aircraft, PG&E complies with all state and federal regulations governing services and gifts to elected officials. For other passengers, use of the airplane must be approved by a Vice President and the PCC or order number for that officer is charged for use of the airplane. (Exhibit PG&E-18, p. 55-6.)

Holding Company employees are treated the same as Utility employees.¹⁸⁵ The Settlement addresses the efficacy of PG&E's charges by requiring PG&E to evaluate its current charges and to report its findings to the Commission.¹⁸⁶

PG&E also testified that its policies prohibit personal use of the plane. To address TURN's concern about the need for a written policy on personal use of the airplane, the Settlement Agreement provides the following written policy:

PG&E employees (including employees, officers, and Board members of PG&E Corporation) will be prohibited from using the Company airplane for personal travel for themselves or their family. PG&E customers and contractors, including customers and contractors of PG&E Corporation, will also be prohibited from using the Company plane for personal travel for themselves or their family. (Settlement Agreement, para. 28.)

If there is a violation of the written policy, the individual will pay for the flight.¹⁸⁷

We conclude that PG&E's existing policies and the Settlement Agreement provisions regarding use of the Company airplane are satisfactory.

¹⁸⁵ 33 TR 3134: 3-9.

¹⁸⁶ Settlement, para. 29.

¹⁸⁷ 33 TR 3150: 23-28, 3151:1-2.

iii. Corporate Real Estate

PG&E's Corporate Real Estate (CRE) department is responsible for the planning, design, construction, maintenance, and operation of over 845 building and yards at more than 190 locations. PG&E's facilities include offices, call centers, data centers, meeting and training facilities, service centers, shops, warehouses, construction yards, and garages. These facilities support day-to-day operations as well as service restoration after storms and natural disasters.

The following tables show PG&E's requested CRE expenses and capital expenditures in 2007 and DRA's proposed disallowances:

2007 Corporate Real Estate Expenses		
Item	Requested Expenses (millions)	Proposed Disallowance (millions)
Building & Yard Maint.	\$11.30	\$6.07
Redevelop. & New Constr.	\$2.00	\$1.00
Building Seismic Safety	\$3.40	\$1.70
Americans w/Disability Act	\$4.80	\$2.40
Building Permit Initiative	\$0.52	\$0.26
Green Building Initiative	\$8.80	\$4.40
Repair & Replace Furniture	\$0.11	\$0.06
Real Estate Management	\$6.90	- -
Total	\$37.83	\$15.89

2007 Corporate Real Estate Capital Expenditures		
Item	Requested Cap. Ex (millions)	Proposed Disallowance (millions)
Tools, Equip., & Furniture	\$5.0	- -
Building & Yard Maint.	\$19.00	\$9.10
Redevelop. & New Constr.	\$18.77	\$11.20
Building Seismic Safety	\$1.88	- -
Building Permit Initiative	\$3.03	\$1.60
Green Building Initiative	\$5.87	\$4.70
Lemoore Service Center	\$0.50	\$0.50
Total	\$54.05	\$27.10

The bulk of DRA's proposed disallowances of CRE expenses was based on its conclusion that PG&E's requested expenses for maintenance, repairs, and upgrades were too ambitious in light of historical expending, and that the requested expenses should be spread over a longer period so as to mitigate the annual financial impact on ratepayers. PG&E responded that the timing of the expenses was driven by the age and condition of its buildings, seismic safety concerns, environmental stewardship, and regulatory compliance.

The majority of DRA's proposed disallowances of CRE capital expenditures stemmed from DRA's conclusion that PG&E's request was excessive in light of historical expenditures and activities. PG&E responded that its requested expenditures were driven by customer growth, the condition of its aging facilities, operational needs, and regulatory compliance.

The Settling Parties agree that the resolution of issues regarding CRE expenses (other than depreciation) is subsumed in the Settlement outcomes for

A&G expenses and O&M expenses.¹⁸⁸ The Settlement provides \$708.7 million for A&G expenses in 2007, which is \$32.8 million less than PG&E requested.¹⁸⁹ With respect to O&M expenses, the Settlement provides \$1.079 billion in 2007, which is \$15 million less than PG&E requested.¹⁹⁰ There is no opposition to the Settlement outcome on CRE expenses.

The Settlement Agreement adopts PG&E's requested CRE capital expenditures.¹⁹¹ There is no opposition to the Settlement outcome on this matter.

We conclude that the uncontested Settlement outcome for CRE expenses and capital expenditures is reasonable in light of the record summarized above. In our opinion, PG&E has justified almost all of its requested expenses for CRE, and all of its requested capital expenditures, which is consistent with the Settlement outcome. The Settlement outcome is also consistent with the law in that much of PG&E's requested CRE expenses and capital expenditures are needed to comply with various local, state, and federal requirements. Finally, the Settlement outcome is in the public interest because it provides PG&E with sufficient revenue to maintain and acquire real estate assets that are necessary to the provision of utility services to the public.

iv. Environmental Programs

PG&E's Environmental Programs encompass the Environmental Affairs department and personnel throughout the Utility who are responsible for (1) compliance with environmental laws, and (2) programs implemented solely

¹⁸⁸ Settlement Motion, p. 188.

¹⁸⁹ Settlement Agreement, para. 31 and Appendix A, Line 16.

¹⁹⁰ Settlement Agreement, para. 17.

¹⁹¹ Settlement Motion, p. 210.

for environmental purposes. PG&E requested the following for Environmental Programs in 2007: (i) \$2.6 million for A&G expenses; (ii) \$14.7 million for O&M expenses; and (iii) \$4.9 million for capital expenditures.

There was no opposition to PG&E's requested O&M expenses and capital expenditures. DRA proposed two reductions to A&G expenses. First DRA proposed a "normalized adjustment" of \$34,776 to remove costs for employee recognition awards; staff lunches, dinners, and parities; and entertainment activities. PG&E responded that these are legitimate business expenses.

Second, DRA proposed a disallowance of \$0.208 million based on PG&E's 2004 recorded expenses instead of PG&E's 2007 forecast. PG&E responded that it will have higher costs in 2007 compared to 2004 because of emerging issues associated with global climate change.

The Settling Parties agree that the resolution of issues regarding Environmental Programs expenses is subsumed in the Settlement outcome for all A&G expenses and O&M expenses.¹⁹² The Settlement provides \$708.7 million for A&G expenses in 2007, which is \$32.8 million less than PG&E requested.¹⁹³ With respect to O&M expenses, the Settlement provides \$1.079 billion in 2007, which is \$15 million less than PG&E requested.¹⁹⁴ The Settling Parties also agree that capital expenditures for Environmental Programs are subsumed in the broader Settlement outcome for capital additions and rate base.¹⁹⁵ The Settlement adopts PG&E's position on capital additions and rate base for common plant.

¹⁹² Settlement Motion, p. 188.

¹⁹³ Settlement Agreement, para. 31 and Appendix A, Line 16.

¹⁹⁴ Settlement Agreement, para. 17.

¹⁹⁵ Settlement Motion, p. 188.

We find that PG&E has justified the great majority of its requested expenses and capital expenditures for Environmental Programs in 2007. It is reasonable to expect that such expenses and capital expenditures will increase significantly in 2007 compared to 2004 due to major new environmental laws, such as the recently enacted law limiting greenhouse gas emissions in California.

DRA's proposed normalized adjustment is consistent with Commission precedent. We interpret the Settlement outcome, which grants PG&E less than it requested for A&G expenses as a whole, as accommodating a 100% disallowance for DRA's normalized adjustment of \$34,776. With this understanding, we find that the Settlement outcome for Environmental Programs is reasonable in light of the record, consistent with applicable law, and in the public interest.

v. Information Technology

PG&E's Information Services and Technology Services (ISTS) organization installs, operates, and maintains many of PG&E's information and telecommunication systems. PG&E requested the following funding for ISTS:

- \$72.37 million for A&G expenses in 2007 and \$55.8 million for Gas and Electric Distribution O&M expenses in 2007.
- \$57.5 million for capital expenditures in 2007.

DRA proposed several reductions to PG&E's requested expenses and capital expenditures for ISTS. No other party addressed ISTS. The disallowances proposed by DRA are shown in the following tables:

Proposed Disallowances of ISTS Expenses in 2007	
Item	millions
Customer Information System (CIS)	\$4.218
SAP Operations	\$0.121
Utility Applications	\$4.254
Security Risk Management A&G	\$7.360
Security Risk Management O&M	\$4.346
Total Proposed Disallowances	\$20.299

Proposed Disallowances of ISTS Cap. Ex in 2007	
Item	millions
Desktop Computers	\$6.640
CIS Infrastructure	\$1.100
Total Proposed Disallowances	\$7.740

The bulk of DRA's proposed disallowances for ISTS expense and capital expenditures was based on DRA's conclusion that PG&E's request for 2007 was excessive compared to historical spending. DRA was also concerned about possible double counting of AMI related costs recovered in other proceedings.

PG&E responded that DRA had overlooked or ignored historical data that showed PG&E's requested expenses and capital expenditures were reasonable. PG&E also argued that its request was reasonable in light of inflation, aging computers, and costly new regulatory requirements (e.g., Sarbanes Oxley). Finally, PG&E denied there was any double recovery of any AMI-related costs.

The Settling Parties agree that (1) the resolution of issues concerning ISTS capital expenditures is subsumed within the overall Settlement outcomes for

capital additions and rate base,¹⁹⁶ and (2) the resolution of issues concerning A&G and O&M expenses for the ISTS organization is subsumed within the overall Settlement outcome for all A&G and O&M expenses.¹⁹⁷ There is no opposition to the Settlement as it pertains to the ISTS organization.

Based on our review of the record, we conclude that the uncontested Settlement outcome for the ISTS organization is a fair compromise, reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Common Plant Capital Expenditures

PG&E requested \$397.938 million for common plant capital expenditures in 2007 (including \$18 million for Diablo Canyon capital). DRA recommended \$256.896 million, for a difference of \$141.042 million. The Settlement Agreement adopts PG&E's position in full.

The Settling Parties agree on the following allocation of the capital expenditures for common plant:

Electric Distribution General Plant	\$2.192 million
Gas Distribution General Plant	\$1.080 million
Electric Generation General Plant	\$52.307 million
Common Plant	<u>\$342.359 million</u>
Total	\$397.938 million

Issues regarding specific components of the Settlement outcome for common plant capital expenditures (e.g., the Company airplane) are addressed elsewhere in today's Opinion. Except as noted elsewhere, we find the Settlement

¹⁹⁶ Settlement Agreement, paras. 27, 43.

¹⁹⁷ Settlement Agreement, paras. 17, 31.

outcome for common plant capital expenditures is reasonable in light of the record, complies with all applicable laws, and is in the public interest.

5. Customer Advances for Construction

Customer Advances for Construction (CAC) are refundable advances paid by developers for new utility facilities and are recorded as an offset (reduction) to rate base. PG&E used its December 2004 recorded CAC balance of \$125.424 million as its 2007 test-year forecast based on the assumption that CAC will remain stable. The Settlement adopts this amount.¹⁹⁸

a. Position of the Parties

TURN states there is a seasonal pattern for CAC. The pattern shows higher CAC balances during the summer, so that the annual average is higher than the year-end figure. So, rather than using a December 2004 amount as proposed by PG&E, TURN recommends that the Commission use the average 2005 CAC balance, thereby raising the CAC forecast by \$2.96 million.

PG&E responds that it used the December 2004 recorded CAC balance to forecast CAC in 2007 because (1) PG&E believes there will not be a substantial change in CAC over the next several years, and (2) the ending 2004 CAC balance is very close to the weighted-average balance for the four-year period of 2001 - 2004. DRA accepted PG&E's forecast as reasonable.

b. Discussion

TURN's recommendation would increase CAC by \$2.96 million for 2007, which is 2.4% above the Settlement amount of \$125.424 million. PG&E and TURN agree that the CAC balance is affected by the level of residential

¹⁹⁸ Settlement Comparison Exhibit, Tables 1-10 and 2-10, line 14 in each table.

construction activity.¹⁹⁹ Recent economic data shows there has been a substantial downturn in residential construction in California. In the first eight months of 2006, homebuilding in California was down nearly 16% from the same period in 2005.²⁰⁰ Based on this data, we conclude that it is reasonable to adopt the Settlement Agreement's slightly lower forecast of CAC in 2007.

6. Transfer of CAC to CIAC

As mentioned earlier, CAC consists of refundable advances paid by developers for new utility facilities. CAC is included in gross plant but excluded from rate base because it represents assets that were not paid with shareholder dollars. However, sometimes CAC is not refunded. When this occurs, it is transferred to contributions in aid of construction (CIAC). Like CAC, the CIAC balance is included in gross plant but excluded from rate base.

PG&E's forecast of CAC was based on 2004 recorded data. PG&E did not forecast CIAC, contending that it was unnecessary to do so because the CAC-to-CIAC transfer has no effect on rate base. The Settlement implicitly adopts PG&E's approach.

a. Position of the Parties

TURN states that PG&E used a budget-based approach to forecast plant-in-service, and there is no line item in the forecast to reduce forecasted plant-in-service (and rate base) for CAC-to-CIAC transfers. TURN maintains that PG&E's forecast of plant-in-service ignores the accumulation of CIAC from

¹⁹⁹ 16 TR 1288, L: 12-15, PG&E/Togneri; TURN Comments on the Settlement Agreement, p. 148.

²⁰⁰ California Department of Finance October 2006 monthly economic update. (http://www.dof.ca.gov/HTML/FINBULL/2006_FB/October/Oct06.asp) We take official notice of this economic data pursuant to Rule 13.9.

CAC-to-CIAC transfers. As a result, PG&E's forecasted rate base to be too high. To remedy this error, TURN recommends that the 2007 rate base be reduced by \$3.784 million based on a four-year average of CAC-to-CIAC transfers. TURN adds that the Commission adopted the exact same recommendation in the recent SCE GRC proceeding.²⁰¹ TURN believes there is no reason to decide this issue differently for PG&E.

PG&E opposes TURN's proposal. PG&E contends there was no need to separately forecast CIAC because the net effect for each CAC-to-CIAC transfer on rate base is zero. PG&E adds that although the Commission adopted an adjustment for CAC-to-CIAC transfers in the recent SCE GRC, the Commission did not address the merits of the issue. Rather, D.06-05-016 rejects SCE's assertion that the issue is immaterial and adopts TURN's proposed amount.²⁰²

b. Discussion

PG&E's forecast of rate base in 2007 is equal to its 2004 rate base plus budgeted increases during 2005-2007. The 2004 rate base reflects then-existing balances for CAC and CIAC.²⁰³ There is no dispute that PG&E's forecast of rate base in 2007 does not reflect an increased amount of CIAC relative to 2004.

PG&E argues that because CAC-to-CIAC transfers have no effect on rate base, it is unnecessary to forecast CIAC in 2007. We are not persuaded. The CIAC balance is not static, but grows over time with CAC-to-CIAC transfers. This can be seen with a simple hypothetical. In the hypothetical, \$10 is recorded in CAC every January 1 and transferred to CIAC every December 31. The

²⁰¹ D.06-05-015, *mimeo.*, pp. 217-218.

²⁰² D.06-05-016, *mimeo.*, pp. 218-219.

²⁰³ Exhibit TURN-1, pp. 77-78.

average CAC balance is always \$10, but the CIAC balance grows by \$10 each year, reaching \$100 after 10 years.

PG&E's forecast of rate base in 2007 does not reflect the increase in CIAC due to CAC-to-CIAC transfers during 2005-2007. Consequently, PG&E's forecasted rate base is too high. The Settlement adopts PG&E's forecast. It is the Commission's long standing policy that rate base should not include CIAC. The failure of the Settlement Agreement to reduce rate base for the accumulation of CIAC is contrary to decades of Commission precedent.²⁰⁴

Although we agree with the merits of TURN's position, we decline to modify the Settlement to reduce rate base in 2007 by \$3.784 million as recommended by TURN. The associated reduction to PG&E's revenue requirement in 2007, as calculated by the RO model, is \$0.225 million. The impact of TURN's proposed reductions is *de minimis* in relation to the rate base and revenue requirement adopted by the Settlement of \$12.550 billion and \$4.927 billion, respectively, and does not warrant our modifying, let alone rejecting, the Settlement Agreement.²⁰⁵

7. Working Cash

Working cash is part of rate base and consists of two elements: (1) funds needed for the utility's daily operations, which is generally calculated by adding and subtracting certain specified items; and (2) the timing of inflows and

²⁰⁴ The following is a partial list of the hundreds of decisions that have excluded CIAC from rate base: D.06-06-036, D.06-05-016, D.05-07-044, D.04-07-034, and D.01-08-039.

²⁰⁵ In its comments on the Alternate Proposed Decision, PG&E promises that in the next GRC proceeding it will remedy the erroneous method it used to forecast CAC-to-CIAC transfers in the instant GRC proceeding. We expect PG&E to uphold its promise.

outflows of cash that is calculated by a lead-lag study. The computation of working cash is guided by Standard Practice (SP) U-16, dated September 13, 1968. A positive amount of working cash represents a permanent investment in the utility and is included in rate base. Negative working cash represents funds provided by ratepayers and reduces rate base.

a. The Settlement Agreement

PG&E forecasted \$140.714 million of working cash in 2007. DRA recommended \$72.767 million.²⁰⁶ The amount sought by PG&E concedes several minor issues raised by DRA and TURN.

PG&E and DRA disagreed on several items of working cash, the most significant being the treatment of franchise fees in the lead-lag study. DRA proposed to increase the weighting of franchise fees in the lead-lag study by including franchise fees recovered in other proceedings and venues.

The Settlement Agreement adopts working cash of \$143.742 million.²⁰⁷ This is \$3.030 million more than PG&E requested and \$70.974 million more than DRA recommended.²⁰⁸ Most of DRA's proposed adjustments to working cash are not incorporated in the Settlement's calculation of working cash. Rather, the working cash adopted by the Settlement is a residual amount that is based largely on the effect that other elements of the Settlement have on the calculation of working cash. The Settling Parties agree that the resolution of all working cash issues is subsumed by the broader Settlement outcome for rate base. The

²⁰⁶ Settlement Agreement, Appendix G, Tables 1-9, 2-9, and 3-9.

²⁰⁷ \$143,742 million = \$53,941 (Electric Distribution) + \$56.381 million (Gas Distribution) + \$33.420 million (Generation). (Settlement, Appendix G, Tables 1-9, 2-9, and 3-9.)

²⁰⁸ Settlement Agreement, Appendix G, Tables 1-9, 2-9, and 3-9.

Settling Parties further agree that the Settlement outcome for working cash reflects consideration of Aglet's and TURN's proposals regarding working cash.

Aglet and TURN proposed that PG&E's working cash be reduced by the amount of customer deposits. TURN proposed a reduction of \$146.8 million and Aglet suggested a reduction of \$164.9 million. Adopting either amount would result in negative working cash. TURN also recommended two adjustments to the lead-lag calculation, resulting in a working cash reduction of \$5.286 million. We address Aglet's and TURN's proposed reductions to working cash below.

b. Customer Deposits

PG&E requires new customers to establish credit under Tariff Rule 6. A customer who does not qualify for credit must submit a deposit pursuant to Tariff Rule 7. PG&E refunds the deposits within 12 months to those customers that have generally paid their bills on time. PG&E must also pay interest on the deposits equal to the three-month commercial paper rate.

PG&E did not request interest on customer deposits as an operating expense. In addition, PG&E did not deduct customer deposits from working cash because SP U-16 stipulates that only "interest-free" customer deposits should reduce working cash. The Settlement adopts PG&E's position.

i. Position of the Parties

(A) Aglet

Aglet recommends that the Commission reduce PG&E's working cash (and rate base) by the amount of customer deposits. Aglet acknowledges that SP U-16 indicates that PG&E's interest-bearing customer deposits should be excluded from the calculation of working cash. However, in SCE's test-year 2003 GRC, the Commission found that circumstances had changed since SP U-16 was issued, and that customer deposits now represent a substantial and permanent

source of capital provided by ratepayers.²⁰⁹ In SCE's test-year 2006 GRC, there was no opposition to reducing rate base by customer deposits. The Commission concurred, stating that it was "reasonable to include the entire forecasted weighted average customer deposit balance as an offset to rate base."²¹⁰

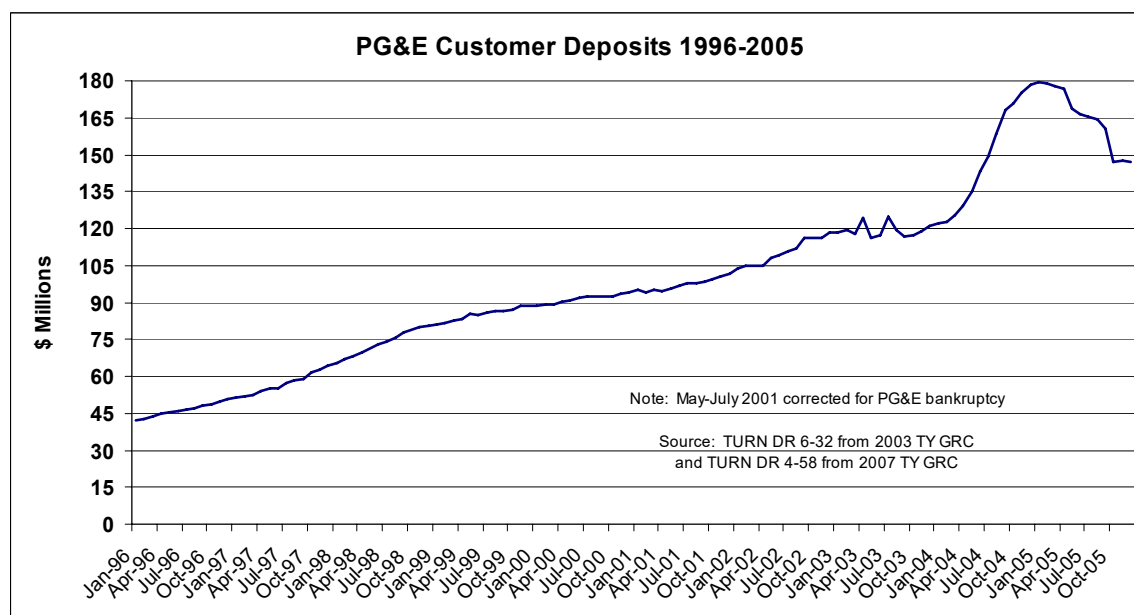
Aglet forecasts customer deposits of \$164.891 million in 2007, the same as the 2005 average. Because customer deposits earn interest at the three-month commercial paper rate, Aglet recommends that PG&E's expenses in 2007 be increased to include this interest expense. Aglet submitted documents that showed the 3-month commercial paper rate reported in Federal Reserve Statistical Release, H-15, dated September 11, 2006, was 5.21%.

(B) TURN

TURN argues that the circumstance which led to a departure from SP U-16 for SCE apply equally to PG&E. TURN represents that the Commission's change in policy for SCE relied on two facts. First, SCE's customer deposits have grown significantly since SP U-16 was issued. TURN provided the following graph that shows PG&E's customers deposits have also grown significantly, rising from less than \$45 million in 1996 to almost \$150 million in December 2005:

²⁰⁹ D.04-07-022, *mimeo.*, pp. 242-247 and FOF 208-210 at p. 332.

²¹⁰ D.06-05-016, *mimeo.*, pp. 279-282, FOF 178 at p. 372.



The second reason for the Commission's change in policy for SCE was a widening of the spread between short-term interest rates and utility rates of return. TURN showed that the three-month commercial paper rate paid on customer deposits is currently around 5.5%, while PG&E's rate of return is approximately 13%, resulting in a spread of 7.5%.

TURN acknowledges that PG&E may have used customer deposits in prior years to finance large balancing account undercollections. However, TURN argues that the undercollections were caused by circumstances that will not recur due to the following new laws and regulations:

- Automatic increases in electric rates are required if power-cost balancing accounts are under collected by 5% or more.²¹¹
- Monthly revisions to gas procurement rates based on monthly gas price forecasts.

²¹¹ See § 454.5(d)(3), which was extended by D.04-12-048, *mimeo.*, p. 113.

TURN believes that the significantly reduced level of PG&E's balancing account undercollections since it exited from bankruptcy in April 2004 demonstrates that the previously identified reforms have permanently reduced the likelihood of large undercollections. In any event, TURN states that the level of balancing account undercollections is irrelevant to whether customer deposits are a permanent source of capital.

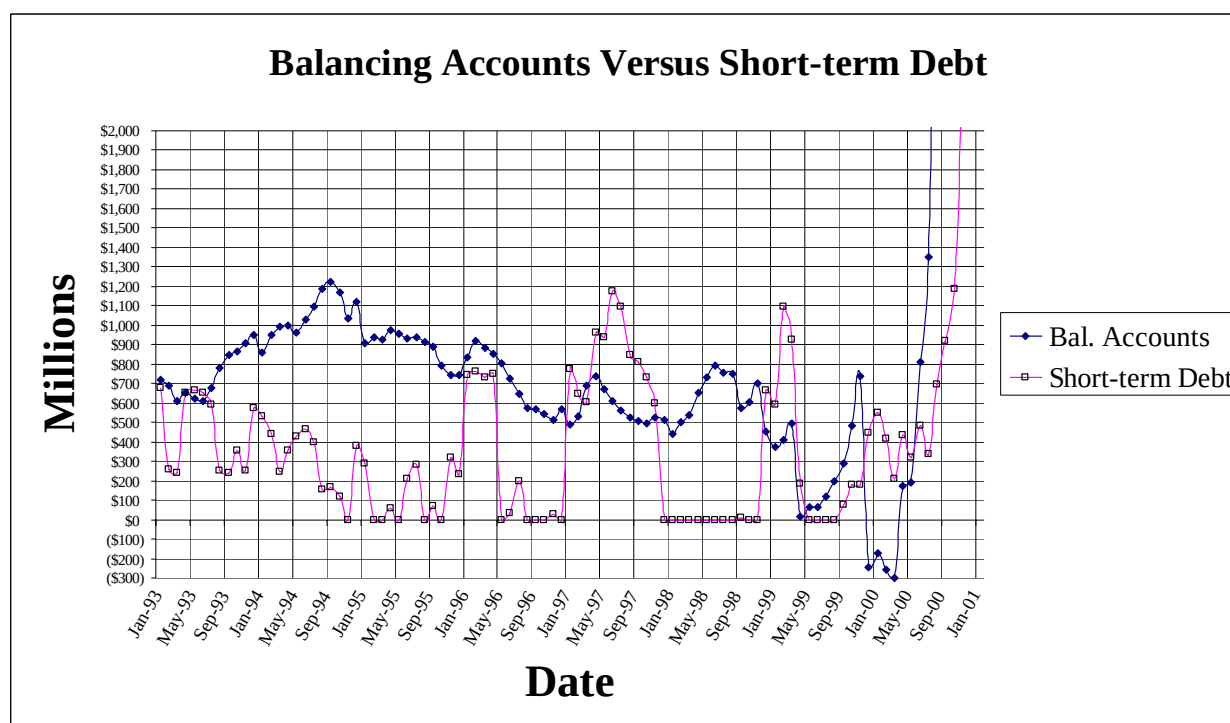
TURN suggests that the most reasonable forecast of customer deposits in 2007 is \$146.775 million, the recorded amount at the end of 2005.

(C) PG&E and the Other Settling Parties

PG&E opposes Aglet's and TURN's recommendation to reduce working cash (and rate base) to reflect customer deposits. PG&E contends their recommendation is contrary to SP U-16, which excludes interest-bearing customer deposits from the determination of working cash.

PG&E represents that it has historically used customer deposits to finance large undercollections in various balancing accounts. PG&E maintains that its balancing accounts were under collected 95% of the time during 1993-2004. These undercollections averaged \$690 million during 1993-1999, and \$3.8 billion during 2000-2004. At the end of 2004, PG&E's balancing accounts were under collected by \$159 million. PG&E believes that undercollections are likely to persist, although perhaps not at historical levels.

PG&E provided the following graph to illustrate that balancing account undercollections have significantly exceeded PG&E's short-term debt:



PG&E submits that the above graph shows that undercollections usually exceeded short-term debt outstanding, which proves that undercollections could not have been financed with short-term debt alone. Moreover, much of the short-term debt shown in the above graph was used for purposes other than balancing account undercollections, which demonstrates PG&E's need to use customer deposits to finance undercollections. PG&E argues that it would be unfair for the Commission to force PG&E to pay 13% on customer deposits when PG&E has consistently used customer deposits to finance balancing account undercollections on which PG&E earns the three-month commercial paper rate.

PG&E disputes TURN's contention that changed circumstances have made large undercollections unlikely in the future. TURN has not shown that undercollections will disappear, only that historical levels may not persist. PG&E also disagrees with TURN's that the level of undercollections since PG&E

exited from bankruptcy in April 2004 presages future undercollections. PG&E states that too little time has elapsed since April 2004 to establish a clear trend.

PG&E maintains that the Commission's decisions in the last two SCE GRC proceedings are not applicable to PG&E because these decisions do not address PG&E's history of large undercollections. More relevant, in PG&E's opinion, is the Commission's decision in PG&E's Test Year 1996 GRC. There, TURN argued that customer deposits should be deducted from working cash. The Commission did not address this issue explicitly, but the Commission's decision utilized SP U-16 to compute working cash, which resulted in the exclusion of customer deposits from the working cash computation.

If the Commission adopts Aglet's and TURN's proposal to decrease working cash for customer deposits, PG&E argues that symmetry demands that the Commission increase working cash for balancing account undercollections. This would be consistent with SP U-16, which provides for symmetrical treatment of short-term assets and liabilities. Specifically, under SP U-16, interest-bearing short-term assets and liabilities are both excluded from the working cash calculation. Similarly, non-interest bearing short-term assets and liabilities are included in the working cash calculation. PG&E contends that all the factors cited by Aglet and TURN for including customer deposits in the working cash calculation apply equally to balancing account undercollections.

In similar vein, PG&E notes the treatment of nuclear fuel inventory by the Settlement. PG&E agreed to remove nuclear fuel from rate base, even though nuclear fuel inventory requires a permanent commitment of capital. PG&E contends that if customer deposits are used to reduce rate base on the theory that they represent a permanent source of capital, it is only fair that nuclear fuel be added to rate base because it requires a permanent commitment of capital.

PG&E disagrees with the amount of customer deposits forecasted by Aglet and TURN for 2007. Aglet forecasted \$164.9 million based on the average of customer deposits during 2005. TURN forecasted \$147 million based on the 2005 year-end customer deposits. PG&E argues that TURN's graph shows that deposit levels were decreasing in 2005, and that trend could continue. Thus, adopting either Aglet's proposal or TURN's proposal could require PG&E to pay 13% on money that PG&E might never receive.

PG&E notes that Aglet would allow PG&E to recover a rate of interest on customer deposits of 5.21%. PG&E states that short-term rates have been increasing. If interest rates continue to increase, PG&E would be required to pay more interest on deposits than it recovers in rates. The net effect would be a loss for PG&E equal to the difference between the short-term rate being paid on deposits and the amount recovered in rates.

ii. Discussion

As a preliminary matter, we find that the uncontested aspects of the Settlement Agreement's computation of working cash to be reasonable in light of the record, consistent with applicable law, and in the public interest. The only concerns we have regarding working cash pertain to the issues raised by Aglet and TURN, which we address below.

The largest issue regarding working cash is whether to adopt Aglet's and TURN's proposal to treat customer deposits as a reduction to working cash. We decline to adopt their proposal. The record shows that PG&E and the Settlement Agreement calculated working cash in accordance with SP U-16, which has been in effect since 1969. As such, we view the Settlement outcome on working cash as presumptively reasonable.

Aglet and TURN raise several arguments for why it is appropriate to depart from a key element of SP U-16. Perhaps their best argument is that the Commission's decisions in the two most recent GRCs for SCE departed from SP U-16 and deducted customer deposits from working cash. They assert that the Commission should treat PG&E the same as SCE. We disagree. Our review of Commission precedent reveals that SCE is somewhat of an aberration in this regard. In the last two years alone there have been numerous Commission decisions that relied on SP U-16 to determine working cash.²¹²

The remaining arguments offered by Aglet and TURN have some merit, but so do PG&E's counter arguments. On the whole, we find that Aglet and TURN have not marshaled sufficient facts and arguments to overcome our presumption that Settlement Agreement's reliance on SP U-16 is reasonable.

For the preceding reasons, we find the Settlement outcome for customer deposits is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

c. Lead-Lag Calculation of Working Cash

TURN proposes two changes to the lead-lag study, which together reduce PG&E's rate base by \$5.286 million. We address each recommendation below.

i. Revenue Lag

(A) Position of the Parties

PG&E's lead-lag study used data from 2004 to calculate the revenue lag. TURN states that because there is variability in the revenue lag data, it is better to use a longer period to calculate an average value. TURN recommends

²¹² See for example, D.05-12-020 and D.05-08-004.

averaging data for 2004 and 2005, which reduces revenue lag by 0.18 days. The adjustment would reduce rate base by \$4.2 million.

PG&E opposes TURN's adjustment on the grounds that it mixes data from different years. PG&E maintains that it is the Commission's general practice to use data from a single year in the lead-lag study.

(B) Discussion

PG&E used 2004 data in all of its working cash calculations, including the revenue lag computation, unless special circumstances existed.²¹³ PG&E saw no special circumstances to use data outside of 2004 to determine the revenue lag.

We decline to adopt TURN's proposal to use data from both 2004 and 2005 to calculate the revenue lag. We agree with PG&E that multiple years should only be used if warranted by special circumstances, which are not present here.

TURN argues that there is variability in the data for revenue lag, but TURN offers no quantification of such variability. PG&E testified that there was only a slight change in data between 2004 and 2005.²¹⁴ Slight changes in data from year to year are common and not worthy of special treatment. Furthermore, TURN selectively chooses to use 2005 data in only part of the working cash calculation. This pick-and-choose approach would set a bad precedent and cause further disputes in the already complex matter of determining "leads and lags" in the working cash study.

²¹³ Exhibit PG&E-2, pp. 12-12 to 12-13; Exhibit PG&E-18, p. 6-6, L: 28-29.

²¹⁴ 11 TR 721:22-24, PG&E/Jones.

ii. Savings Fund Lag

(A) Position of the Parties

PG&E's working cash calculation assumes zero lag days for the Company's matching contributions to the savings pool. TURN submits that the lag for the matching savings-fund contributions should be 16.81 days, the same as the lag for payroll less 0.49 days for float. Adopting TURN's recommendation would reduce rate base by \$1.111 million.

PG&E responds that TURN's proposal is contrary to the Commission's treatment of this issue in PG&E's 1996 GRC:

TURN recommends that savings fund contributions be accorded the same number of...lag days as payroll. TURN believes that, like payroll taxes (FICA), employee savings contributions are incurred at the same time labor cost is incurred. PG&E has agreed to make a similar adjustment for FICA...PG&E responds that, unlike FICA, it does not incur employee savings contributions until...the employee is paid. FICA is incurred over the period the obligation to the employee is incurred. PG&E makes a reasonable argument that FICA obligations are incurred differently from employee savings contributions. We will adopt PG&E's proposal. (D.95-02-015, 63 CPUC 2d 570, 617.)

PG&E concedes that its treatment of lag days for savings-fund contributions is not precise. Nevertheless, PG&E argues that its use of zero lag days is preferable to TURN's recommendation for two reasons. First, TURN's proposal is based on the average lag in wage payments, including performance incentive payments (PIP). The PIP extends the computed wage lag by taking into account PIP payments in mid-March of the following year. In contrast, matching savings-fund contributions are paid only on regular wages paid during the year

(or in the first week of January of the following year). Thus, associating the savings-fund lag with the wage lag (including PIP) creates a lag that is too long.

Second, savings-fund contributions are front loaded towards the early part of the year. As with FICA taxes that stop when an employee reaches the wage limit for the year (\$87,900 in 2004), PG&E's matching contributions to the savings fund stop when the employee reaches the 401(k) limitation.

If the Commission adopts TURN's proposal for computing the lag on savings-fund contributions, PG&E states that the proposal would need to be refined to better account for "front-loading."

(B) Discussion

TURN seeks to adjust the lag days for PG&E's matching contributions to the savings fund so that the savings-fund lag matches payroll lag. Adopting TURN's proposal would change the savings-fund lag from zero to 16.81 days,²¹⁵ reduce PG&E's rate base by \$1,111,000, and reduce PG&E's revenue requirement by approximately \$144,000 in 2007.

We agree with the logic of TURN's proposal. PG&E makes its matching contributions to the savings fund at the same time it pays wages. Thus, the two should be treated similarly in the working cash calculation.

Although we agree with TURN's proposal, PG&E raises two valid technical objections that we cannot resolve here. First, PG&E represents that savings-fund contributions are paid only on regular wages and not on PIP, so using the payroll lag as proposed by TURN (which includes PIP paid in March of

²¹⁵ Exhibit TURN-1, p. 86.

the following year) would overstate the lag.²¹⁶ Second, PG&E testified that savings-fund contributions (which are a match of employee contributions) tend to be front loaded during the year because of IRS limitations and otherwise.²¹⁷ PG&E's matching contributions to the savings fund plan end when the employee reaches the 401(k) limitation. TURN's proposal overstates lag because it assumes the payroll lag and the savings-fund contribution lag are the same.

There is an insufficient record to determine by how much the adopted revenue requirement reduction of \$144,000 should be reduced to reflect PG&E's two corrections. We conclude that because \$144,000 is insignificant in relation to PG&E's multi-billion revenue requirement adopted by today's Opinion, and because the \$144,000 should be reduced for the previously stated reasons, that the appropriate reduction to PG&E's rate base and revenue requirement is already reflected in rate base and revenue requirement adopted by the Settlement, both of which are lower than what PG&E requested in A.05-12-002.

In its next GRC proceeding, PG&E shall incorporate into the calculation of working cash a lag for employer savings-fund contributions in a manner consistent with today's Opinion.

The resolution of the savings-fund-contribution issue by today's Opinion is not inconsistent with D.95-02-015. There, the Commission appears to have addressed the lag for savings-fund contributions by employees. Today's Opinion addresses savings-fund contributions by the employer. Thus, the two decisions address somewhat different issues. Further, PG&E concedes in the instant proceeding that "its current treatment [of the employer's matching

²¹⁶ Exhibit PG&E-18, p. 6-8, L: 4-11.

²¹⁷ 11 TR 750:4-18, PG&E/Jones.

savings-fund contributions] may not be a precise computation of the ratemaking lag.²¹⁸ In light of PG&E's concession, the facts and circumstances in the instant proceeding warrant a different outcome than D.95-02-015.

8. Depreciation Expense

The purpose of depreciation expense for ratemaking purposes is to allow a utility to recover the costs it incurs to buy, install, and remove assets over the useful life of the assets. The Commission determines depreciation expense on an accrual basis using the straight-line, remaining life method described in Commission Standard Practice (SP) U-4, *Determination of Straight-Line Remaining Life Depreciation Accruals*, dated January 3, 1961. This method uses the following formula to calculate the annual depreciation expense accrual:

Depreciation Expense =	$\frac{\text{Plant Balance} - \text{Reserve} - \text{Gross Salvage} + \text{Cost of Removal}}{\text{Remaining Service Life of Asset(s)}}$

The components of the depreciation expense accrual are as follows:

Plant balance is equal to the original cost of assets (other than land) used to provide service to customers.

Reserve is the accumulated depreciation expense recorded to date for existing plant-in-service.

Gross salvage is the estimated future scrap value that will be realized when existing plant-in-service is retired.

Removal cost is the estimated future cost to remove existing plant-in-service.

²¹⁸ Settlement Motion, p. 239.

Remaining life is the expected average remaining life of plant-in-service.

In A.05-12-002, PG&E requested \$1.024 billion for depreciation expense in 2007 based on SP U-4 and the parameters in PG&E's testimony (e.g., remaining life and gross salvage).²¹⁹ The only parties to contest PG&E's request were TURN and DRA. Both parties disagreed with PG&E's forecast of net salvage.²²⁰ DRA also contested PG&E's proposal for refunding excess accumulated depreciation for fossil generation decommissioning.

a. Issues Raised by DRA

i. The Settlement Agreement

PG&E used SP U-4 to forecast depreciation expense in 2007. DRA agreed with this method, but advocated higher net salvage rates.²²¹ DRA's proposal was based on its observation that PG&E in recent years has collected around \$180 million annually for removal costs but has spent less than \$80 million annually. DRA's proposed net salvage rates would allow PG&E to collect

²¹⁹ Exhibit PG&E-2, p. 9-12 to p. 9-16, and Table 9-2.

²²⁰ Net salvage is gross salvage less removal costs. Net salvage can be positive or negative. For most retirements, removal costs are much higher than gross salvage value, resulting in negative net salvage.

²²¹ The net salvage rate is net salvage divided by the original cost of the plant being retired. The net salvage rate is often negative. For example, a utility pole that cost \$100 to install in 1960 and \$150 to remove and retire in 2000 will have a net salvage of -\$150 and a net salvage rate of -150% [-150% = -150/100]. If this asset class has a plant balance of \$600 million in 2000 and the previously described net salvage relationship applies to the entire account, the depreciation expense recovered in rates over the remaining life of the plant would be \$1,500 million less the depreciation reserve. The \$1,500 million is composed of \$600 million for the current plant balance and \$900 million (150% of \$600 million) for the expected future removal costs (i.e., negative net salvage).

\$9.6 billion of the \$12.3 billion that PG&E estimated it would need for negative net salvage over the next 30 years for existing Distribution assets.

PG&E responded that DRA used improper techniques to reduce negative net salvage. For example, PG&E's depreciation study used 15 years of historical data. Although DRA used the same data, PG&E claims that DRA excluded data for outlier years that reduced negative net salvage, but DRA did not exclude data for outlier years that went the other way. Similarly, DRA compared PG&E's negative net salvage to other utilities when the comparison resulted in a lower revenue requirement for PG&E, but DRA omitted comparisons that went the other way.

The Settlement Agreement adopts most of DRA's proposed net salvage rates. The following Table compares the Settlement with PG&E's and DRA's positions on depreciation expense:

2007 Depreciation Expense (\$ millions)							
	2006 Authorized	Comparison Exhibit		Settlement 2007	Variances Increase/(Decrease)		
		PG&E 2007	DRA 2007		Settlement vs. 2006	Settlement vs. PG&E	Settlement vs. DRA
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
Depreciation	839	1,024	939	942	103	(82)	3
(Source: Settlement Agreement, Appendix A, p. 23, L: 31.)							

As shown in the above Table, the Settlement Agreement is very close to DRA's position on depreciation expense. Virtually all of the difference between PG&E's request and amount adopted by the Settlement is attributable to those DRA net salvage rates adopted by the Settlement.

The other issue contested by DRA concerned the refund of excess accumulated depreciation for fossil generation decommission costs. DRA and PG&E agreed there should be a refund, but disagreed on the amount of interest that should accrue on the refund. PG&E argued that the refund has been carried in the depreciation reserve for fossil decommissioning. This has had the effect of reducing rate base, with a corresponding benefit to ratepayers equal to the annual pre-tax rate of return of approximately 13%. DRA proposed that ratepayers receive an additional 5% interest on the over-accrual.

In rebuttal, PG&E maintained that customers have benefited from the reduced rate of return on rate base and will continue to do so until the over collection is refunded. The Settling Parties agree that ratepayers should retain the rate base reduction but not receive 5% interest on top of that.²²²

ii. Discussion

We find that the amount of depreciation expense adopted by the Settlement Agreement is reasonable in light of the record. PG&E submitted a comprehensive depreciation study, and the parties collectively submitted more than 900 pages of testimony on depreciation expense. This substantial record readily supports PG&E's requested depreciation expense, except for the net salvage component of depreciation.

With regards to net salvage, DRA has demonstrated that PG&E's net salvage rates are too low, since in recent years PG&E has collected about \$180 million annually for removal costs but has spent less than \$80 million

²²² Settlement, para. 42.

annually.²²³ In A.05-12-002, PG&E requested \$379 million annually for removal costs, but projected it would spend only \$88 million annually. The Settlement Agreement authorizes PG&E to recover \$299 million annually, which is very close to DRA's recommendation of \$296 million.²²⁴ Although the Settlement still has a gap of \$211 million between the amount of future removal costs that PG&E will collect in rates annually and the amount expended annually, this gap is normal and reasonable. As noted by PG&E, the annual accrual of future removal costs will exceed annual expenditures when, as here, new assets are being added faster than old assets are being removed and projected future removal costs are higher than current removal costs due to anticipated inflation.²²⁵

We also find that the amount of depreciation expense adopted by the Settlement Agreement is consistent with the law. Because the Settlement allows PG&E to recover a reasonable amount of depreciation expense, the Settlement is consistent with the Commission's authority under § 795 to set "proper and adequate rates of depreciation...[for] each public utility."

Finally, we conclude that it is in the public interest to authorize PG&E to recover the amount of depreciation expense set forth in the Settlement. The provision of gas and electric service to the public requires substantial investment. Utilities must recover the reasonable costs they incur to make such investments, including depreciation expense, in order to provide gas and electric service. The Settlement Agreement allows PG&E to recover its reasonable depreciation

²²³ Exhibit DRA-16, p. 16-10.

²²⁴ Settlement Motion, p. 247.

²²⁵ Settlement Motion, p. 270.

expense, including a reasonable amount of removal costs, and thereby enables PG&E to provide vital gas and electric service to the public.

We also find reasonable the Settlement's provisions on the interest owed by PG&E on a pending refund of excess accumulated depreciation for fossil decommissioning expense. We agree with PG&E's position that fossil decommissioning expense is part of the depreciation reserve and reduces rate base. Ratepayers have, in effect, earned interest on the excess decommissioning expense at a rate equal to PG&E's authorized rate of return, and will continue to do so until the over-collection is refunded.²²⁶ Thus, it is unnecessary for PG&E to pay additional interest on the refund as originally proposed by DRA.

b. Depreciation Issues Raised by TURN

TURN makes three proposals regarding the net salvage component of PG&E's depreciation expense accrual. First, TURN proposes that PG&E establish a regulatory liability for the money that PG&E has collected in rates for future removal costs but has not yet spent. Second, TURN asks the Commission to set PG&E's depreciation expense using what TURN calls "normalized net salvage" instead of the current straight-line remaining life method. Finally, TURN believes that PG&E should provide in its next GRC a depreciation study that uses the net present value approach described in SFAS No. 143 to determine future removal costs. We address each of TURN's proposals below.

i. Regulatory Liability for Removal Costs

Under SP U-4, the future cost to remove existing assets is recovered as part of depreciation expense on a straight-line basis over the average expected life of

²²⁶ Exhibit PG&E-18, p. 3-7, L: 1-7.

the assets. Thus, by the time an asset is retired, the utility has, on average, recovered the entire cost to remove the asset. Removal costs recovered in depreciation expense are part of the depreciation reserve and reduce rate base.

By the end of 2005, the cumulative amount of removal costs that PG&E had collected in rates exceed actual expenditures by \$2.1 billion. Most of the \$2.1 billion of pre-funded removal costs will not be spent for many years. Under the Settlement Agreement, the amount of removal costs that PG&E collects in rates will continue to exceed actual expenditures by approximately \$211 million annually. Thus, by the end of 2010, PG&E will have collected more than \$3.0 billion for removal costs that it has not yet spent.

For external financial reporting purposes, PG&E reports pre-funded removal costs as a regulatory liability pursuant to SFAS 71. Under generally accepted accounting principles (GAAP), a regulated entity such as PG&E must record a regulatory liability for future costs when (1) the regulator has provided rates to recover specified future costs, and (2) the regulated entity must return the funds collected in rates if the future costs do not materialize. The obligation to return the funds can be fulfilled either by future rate reductions or by paying other future costs with no corresponding effect on future rates.

(A) Position of the Parties

(1) TURN

TURN recommends that PG&E record in its regulatory books a regulatory liability for pre-funded removal costs. Excluded from TURN's recommendation are asset retirement obligations (AROs) that PG&E reports on its external

financial statements pursuant to SFAS 143.²²⁷ TURN does not explain why AROs are excluded from its proposal, even though PG&E's AROs are substantial.²²⁸

The basis for TURN's proposal is its concern that PG&E will not use the \$2.1 billion of pre-funded removal costs that it has already collected in rates to pay for removal costs. TURN believes that recording a regulatory liability on PG&E's regulatory books will help to ensure that PG&E either uses the \$2.1 billion for its intended purpose or returns these funds to ratepayers.

TURN recognizes that PG&E already reports the \$2.1 billion of pre-funded removal costs as regulatory liability on its external financial statements pursuant to SFAS 71. In doing so, PG&E has acknowledged that the Commission expects PG&E to either use the \$2.1 billion to pay for future removal costs or return these funds to ratepayers. However, there is no Commission decision that explicitly establishes this requirement. TURN believes it is necessary for the Commission to explicitly create a regulatory liability for pre-funded removal costs given PG&E's testimony that accumulated depreciation represents capital that belongs to investors rather than ratepayers.²²⁹

(2) Aglet

Aglet supports TURN's recommendation. Aglet states that TURN has identified a situation where ratepayers have pre-paid billions of dollars for removal costs but won't receive the benefit for decades. Given this situation, Aglet believes the Commission should explicitly order that PG&E's pre-funded

²²⁷ AROs are legal obligations to incur future costs to remove existing assets.

²²⁸ PG&E's SEC Form 10K for 2005 shows that as of December 31, 2005, that PG&E's regulatory liability for AROs was \$538 million, which was in addition to the regulatory liability of \$2.141 billion for pre-funded removal costs.

²²⁹ Exhibit TURN-53, Response to Q/ A 0001-73(h) and (i); 27 RT 2609-10, PG&E/White.

removal costs must be spent on removal costs or returned to ratepayers.

Although there is only a small probability that ratepayers might lose these funds in a future sale of the utility or other circumstances, Aglet contends that the stakes are too high for the Commission to ignore the issue.

(3) SCE

SCE intervened in this proceeding for the limited purpose of addressing the depreciation policies advocated by TURN. SCE takes no position on the specific depreciation rates or PG&E's revenue requirement.

SCE maintains that a regulatory liability is an accounting device that is limited to external financial reporting. The Commission has no need to establish regulatory liabilities for ratemaking purposes, according to SCE, because the Commission already has all the authority it needs to oversee and control the disposition of pre-funded removal costs.

(4) PG&E and the Other Settling Parties

PG&E believes it is unnecessary for the Commission to create a regulatory liability because the pre-funded removal costs will eventually be incurred regardless of (1) how PG&E accounts for these costs, or (2) any future changes to the regulatory framework under which PG&E operates.

(B) Discussion

PG&E receives a huge amount of capital from ratepayers to pre-fund future removal costs. The record shows that as of the end of 2005, the cumulative amount of removal costs that PG&E had collected in rates exceeded

cumulative expenditures by \$2.1 billion. The Settlement allows this figure to grow by \$211 million annually during 2007-2010.²³⁰

The *quid pro quo* for ratepayers is that PG&E will use the money it collects to pre-fund future removal costs to pay for removal costs. PG&E has recognized this regulatory bargain in its external financial statements where it reports a regulatory liability for pre-funded removal costs. Under SFAS 71, pre-funded removal costs can be reported as a regulatory liability only if the funds will be spent on removal costs or returned to ratepayers.

TURN and Aglet recommend that PG&E be required to classify pre-funded removal costs as a regulatory liability for ratemaking purposes. We agree for several reasons. First, doing so accurately reflects the regulatory bargain. Second, it is consistent with GAAP as demonstrated by the way PG&E reports pre-funded removal costs on its external financial statements. Finally, it provides an extra measure of assurance that PG&E will only use the amounts that it collects to pre-fund removal costs for their intended purpose.

SCE argues that it is unnecessary to classify pre-funded removal costs as a regulatory liability for ratemaking purposes. We disagree. PG&E has accumulated \$2.1 billion for removal costs that will not be incurred for years or decades. Under the Settlement, this amount will continue to grow at the rate of more than \$200 million per year. With the stakes so high and the actual incurrence of the removal costs far in the future, we conclude that it is appropriate to establish the regulatory liability as a reasonable protection of ratepayers' interest in making sure the huge amount of money collected for

²³⁰ Settlement Motion, p. 247 (difference between Settlement revenue requirement for future removal costs and projected asset removal expenditures in 2007).

removal costs is either spent for that purpose or returned to ratepayers (either in the form of a rate reduction or as an offset to other costs). Our action today will cause no harm to PG&E's shareholders, since PG&E already reports a regulatory liability for external financial reporting purposes.

We are also concerned about the consequences of our not adopting a regulatory liability. Pursuant to SFAS 71, a necessary condition for reporting a regulatory liability on external financial statements is a "rate action" that imposes a liability on a regulated entity.²³¹ The issue of whether PG&E should create a regulatory liability for pre-funded removal costs is squarely before us. If we decline to require PG&E to record a regulatory liability for ratemaking purposes, there will be less reason for PG&E to do so for external financial reporting purposes. We believe that such an outcome would undermine the regulatory bargain described previously, which is not our intent.

Our adoption of a regulatory liability for PG&E's pre-funded removal costs is consistent with our resolution of the same issue in the most recent SCE GRC proceeding. There, we held that:

TURN's request that the balance of funds collected for cost of removal...be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted. The balance...is substantial, amounting to \$2.1 billion as of the end of 2004. This balance is already recognized as a regulatory liability for financial reporting purposes. SCE has not demonstrated any potential harm to the company...Formal recognition of our ratemaking responsibilities is a reasonable course of action and will establish regulatory certainty regarding ratemaking

²³¹ SFAS 71, para. 11.

treatment and principles that all parties generally agree is appropriate. (D.06-05-016, *mimeo.*, p. 204.)

We see no reason to treat PG&E differently from SCE.

We emphasize that our adoption of a regulatory liability for PG&E's pre-funded removal costs in no way prejudices how we might treat the regulatory liability if there is ever partial or full deregulation. We recognize, however, that if such an event were to occur, and PG&E has future removal costs at that time, PG&E may be entitled to keep some or all of the pre-funded removal costs in existence at that time to pay for future removal costs.

As noted earlier, PG&E reports a substantial regulatory liability for AROs on its external financial statements. We concur with this accounting. We invite parties to address in the next GRC whether it is necessary and reasonable to explicitly order PG&E to establish a regulatory liability for AROs.

ii. TURN's Normalized Net Salvage Proposal

PG&E estimated the future removal costs included in depreciation expense in accordance with the instructions in SP U-4. Using this guidance, PG&E first determined the ratio of recorded removal costs to recorded asset retirements for the last 15 years. PG&E multiplied this ratio by the current gross plant to project future removal costs. The projected future removal costs were then spread evenly over the average remaining life of existing plant-in-service.

Using the previously described method, PG&E estimated that it will cost approximately \$12 billion in future-year dollars to remove its entire gas and electric distribution system. PG&E spread this amount over 30.7 years to arrive at an annual accrual for future removal costs of \$379 million.

DRA agreed with the methodology that PG&E's used to estimate future removal costs, but DRA disagreed with some of the parameters used by PG&E.

Using its own parameters, DRA recommended that PG&E be allowed to recover \$296 million of removal costs in 2007.

TURN disagreed with the methodology used by PG&E. TURN recommends that PG&E be authorized to recover removal costs based on what TURN calls the “normalized net salvage approach.” Under TURN’s approach, the amount of removal costs recovered in rates would equal the annual average of PG&E’s out-of-pocket costs for the previous three years or five years. TURN’s proposal would allow PG&E to recover \$88 million in 2007 if a three-year period is used, and \$68 million if a five-year period is used.

The Settlement Agreement adopts removal costs of \$299 million in 2007 using PG&E’s method for forecasting removal costs combined with most of the parameters recommended by DRA. The Settlement is \$81 million less than PG&E requested and very close to DRA’s recommendation of \$296 million. The Settlement does not incorporate any elements of TURN’s recommendation.

(A) Position of the Parties

(1) TURN

TURN has two objections to the way removal costs are estimated in the Settlement Agreement. First, the Settlement forecasts removal costs in future-year dollars, and then spreads the future costs over the service life of plant-in-service. Because of inflation, future removal costs will be much higher than today. So, if an asset in 2007 has an expected service life that extends to 2037, ratepayers in 2007 will use 2007 dollars to pay removal costs stated in year 2037 dollars, ratepayers in 2020 will pay in 2020 dollars, and so on. Thus, ratepayers in 2007 will pay more in real dollars than ratepayers in 2020 and other future years. TURN believes this is illogical and unfair to ratepayers in 2007. TURN also contends that forcing ratepayers to pay for inflation that has not yet

occurred is why PG&E has accumulated \$2.1 billion in unspent future removal costs, a figure that will increase by \$211 million annually under the Settlement.

TURN's second concern is that the method used to estimate future inflation implicitly assumes that future inflation will match historical inflation. If the implicit inflation rate is too high, current customers will pay more than they should for future removal costs. If the forecasted inflation rate is too low, current customers will pay less than they should for future removal costs. Either way, ratepayers will pay too much for inflation or too little.²³²

TURN represents that SP U-4 does not mandate the use of inflation in the determination of removal costs. Rather, SP U-4 calls for removal costs to reflect "anticipated changes in labor costs for the immediate future."²³³ TURN asserts that including inflation from the distant future in the current accrual for removal costs is inconsistent with the emphasis in SP U-4 on "the immediate future."

For the previous reasons, TURN recommends that the Commission eliminate inflation from the determination of removal costs. TURN proposes that removal costs for this GRC cycle be based on a rolling three-year or five-year average of PG&E's recorded removal costs. TURN calls this alternative the "normalized net salvage approach." PG&E's revenue requirement for removal costs in 2007 would be \$88 million based on a three-year average of historical removal costs or \$63 million based on a five-year average.

²³² TURN adds that to the extent future inflation is assumed to be greater than zero, and to the extent current rates include future removal costs stated in nominal dollars, there will always be an overpayment that is occurring from a real-dollar perspective.

²³³ Exhibit PG&E-54, p. 40.

(2) PG&E and the Other Settling Parties

The Settlement Motion contains the following table to show the difference between the Settlement Agreement and TURN's proposal. The table shows on an illustrative basis (1) the 2007 revenue requirement for removal costs using the Settlement's SP U-4 accrual method and TURN's normalized net salvage method; (2) the approximate 2007 rate reduction from the reduction in rate base attributable to pre-funded removal costs; (3) the net 2007 revenue requirement for removal costs; and (4) projected expenditures for removal costs in 2007.

Comparison of 2007 Cost-of-Removal (COR) Revenue Requirement (In Millions)		
	Settlement [A]	TURN [B]
1. 2007 COR Revenue Requirement	299	88
2. Less: Rate Benefit from Reduced Rate Base Associated for Pre-Funded COR [C]	(150)	(150)
3. Net 2007 COR Revenue Requirement (Line 1 - 2)	149	(62)
4. Projected COR expenditures (2007) [D]	88	88
5. Net 2007 COR Revenue Requirement compared with 2007 projected COR expenditures (Line 3 - 4)	61	(150)
<u>Notes</u>		
[A] Traditional SP U-4 accrual method.		
[B] Normalized net salvage method based on the 3-year average of 2002-2004 recorded removal costs (PG&E-2 WP, Chapter 10, p 10-11 to 10-211).		
[C] Rate reduction based on \$2.1 billion of pre-funded removal costs (and corresponding reduction to rate base) less deferred taxes (approximately \$800 million) multiplied by PG&E's pre-tax rate of return (approximately 13.1%).		
[D] Projected 2007 COR expenditures based on the 3-year average of 2002-2004.		

The above Table shows that under the Settlement Agreement, ratepayers will pay \$299 million in 2007 to pre-fund future removal costs and receive a benefit of \$150 million from the rate base reduction for pre-funded removal costs.

The net cost to ratepayers in 2007 is \$149 million, which is approximately \$61 million more than forecasted removal expenditures of \$88 million in 2007.

PG&E states that the Settlement's forecast of removal costs of \$299 million is a conservative estimate. To demonstrate this point, the Settlement Motion provides an example based on PG&E's testimony that it had 2.3 million utility poles with an average replacement cost in 2007 of approximately \$6,000 per pole. On average, current removal costs constitute 10% of replacement costs, or \$600 per pole. The Settlement adopts future removal costs of \$1.52 billion for existing poles over the next 30.7 years. This equates to an average future removal cost of under \$700 per pole (i.e., \$1.52 billion divided by 2.3 million poles) for recovery over the next 30.7 years. This also equates to a conservative inflation rate of less than 0.5% annually (i.e., an increase from \$600 to \$700 over the 30.7-year average remaining life). Thus, TURN's concerns regarding enormous over-accruals using SP U-4 are unfounded.

TURN's proposal would have ratepayers pay only the historical three-year average cost of \$88 million. PG&E asserts that the three-year average does not take into account the far greater quantity of assets that will be removed in the future at a far higher unit cost. It also ignores the estimated \$150 million annual rate reduction from the \$2.1 billion reduction to rate base for pre-funded removal costs. As a result, TURN's proposal would provide a net rate reduction of \$62 million (\$88 million - \$150 million) due solely to an accounting change.²³⁴

²³⁴ Stated otherwise, if the normalized net salvage approach had been in effect all along there would be no pre-funded reserve and no rate base reduction. Rates for the current vintage of customers would be \$150 million higher if that were the case.

PG&E believes the \$62 million rate reduction unfairly benefits current ratepayers at the expense of future ratepayers.

PG&E disagrees with TURN's position that reflecting future cost levels in current depreciation is unfair to current ratepayers. TURN states:

If "intergenerational equity" is a guiding principle on such issues, the Commission needs to assign the costs of inflation to the generation of ratepayers that will pay those costs with inflated dollars. In other words, let current ratepayers bear the costs of current inflation, and leave the 2030 inflation to be borne by ratepayers in 2030. (TURN Comments, p. 112.)

PG&E argues that TURN's position conflicts with SP U-4, which states that the straight-line accrual method for depreciation used by DRA and PG&E meets the objective of an equitable sharing of costs.²³⁵

PG&E disputes TURN's argument that SP U-4 does not mandate depreciation rates that include future inflation for removal costs. Chapter 7 of SP U-4 includes numerical examples and tables that illustrate the calculation of removal costs. Since the adoption of SP U-4 in 1961, many depreciation studies have been completed and numerous Commission decisions have been issued that utilize the method described in SP U-4. PG&E maintains that it adhered to this guidance and precedent.

(3) SDG&E and SCG

SDG&E and SCG (together, Sempra) joined the Settlement Agreement for the sole purpose of supporting the use of SP U-4 to compute removal costs.

²³⁵ Exhibit PG&E-54, p. 5, para. 2.

Sempra states that TURN's proposed net-salvage approach is premised on TURN's allegation that PG&E will never spend the money for removal costs at the level it is collecting from ratepayers. Sempra maintains that TURN did not provide any evidence to support its allegation.

Sempra also disputes the following statement by TURN that SP U-4 prohibits the use of inflation in determining removal costs:

SP U-4 calls for basing predicted future cost of removal by "reflecting anticipated changes in labor cost for the immediate future." Including inflation costs going some years, even decades, into the future is inconsistent with the emphasis of SP U-4 on the "immediate future." (TURN's Comments filed on Sept. 20, 2006, p. 126.)

Sempra contends that TURN misconstrues SP U-4. TURN interprets the term "immediate future" to mean that future inflation is not prescribed in SP U-4. That is an incorrect interpretation of SP U-4, according to Sempra.

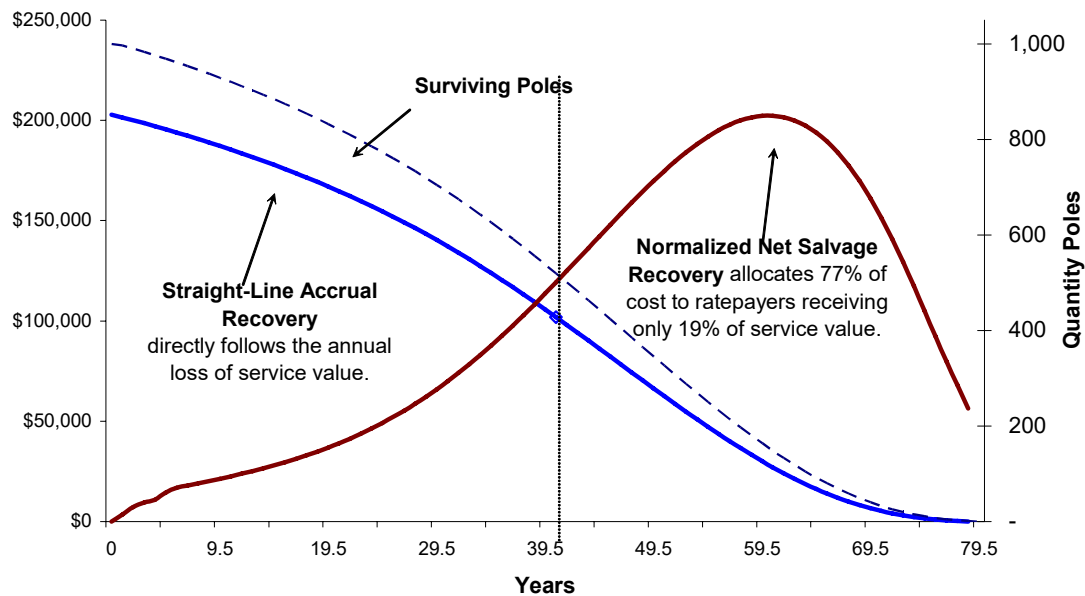
(4) SCE

SCE provides an example to illustrate the deferral of removal costs under TURN's proposal. Assuming \$1,000 of removal costs and a 10-year asset life, TURN's method would not allocate any costs to ratepayers during the asset's life. Instead, after the asset retires in year ten, ratepayers who did not benefit from the asset would bear the entire cost of removal over the ensuing three-year or five-year period. In contrast, the traditional SP U-4 accrual method allocates net salvage costs of \$1,000 over the asset's service life and to those ratepayers who receive the benefits of the asset.

SCE states that the recovery pattern for a single asset would also hold for a group of assets. SCE compared the cost recovery patterns for a group of utility poles that follow PG&E's service life and retirement dispersion characteristics.

As shown below, the SP U-4 accrual method recovers removal costs in a manner consistent with the pattern of the surviving poles' declining service value; TURN's normalized net salvage method would not.

Comparison of Removal Cost Recovery Pattern



Although only about 20% of the poles' collective service value remains after the first 40 years (area to the right of the vertical line), TURN's approach assigns nearly 80% of the removal costs to the ratepayers receiving service after this point. That is, the ratepayers who receive the last 20% of the service value of the poles would bear about 80% of the removal costs for all of the poles.

SCE argues that the above graph shows that TURN's pay-as-you-go approach shifts cost responsibility from current customers, who enjoyed the benefit of the asset's service value, to future customers. SCE claims that TURN presents no evidence to justify such a drastic change in Commission policy.

SCE claims that TURN wrongly asserts that the intent of SP U-4 is to exclude inflation from the computation of removal costs. SCE reads SP U-4 as advocating the widely-held practice of using the ratio of recorded net salvage costs to recorded plant retirement amounts (i.e., net salvage ratios) to estimate future removal costs. Consequently, SP U-4 incorporates an inherent inflation impact because of the time difference between the recorded costs reflected in the numerator and denominator.

(B) Discussion

The issue before us is whether to adopt TURN's proposed "normalized net salvage allowance approach" for setting rates to recover asset removal costs. Under TURN's approach there will be no recovery of removal costs until after assets have retired and the associated removal costs have been incurred. TURN's method is, in effect, a form of cash-basis accounting.²³⁶

TURN's proposal is a marked departure from the current accrual accounting for removal costs. The purpose of using accrual accounting is to allocate to current ratepayers their *pro rata* share of the costs that will eventually be incurred to remove those assets that are currently being used to provide utility service. This treatment is in harmony with GAAP, the USOA, and long-standing Commission practice under SP U-4.²³⁷

Accrual accounting for removal costs is fair to ratepayers because it ensures that ratepayers pay for the removal costs of those assets that serve them, and pay no removal costs for assets that do not serve them. On the other hand,

²³⁶ Exhibit PG&E-20, p. 11; Exhibit SDG&E-SCG-1, pp. 8-9; Exhibit SCE-1, pp. 11-15; and Exhibit TURN-3, p. 48.

²³⁷ FERC USOA, General Instruction 11; SP U-4, p. 5.

TURN's proposal would require ratepayers to pay for removal costs incurred in prior years for assets that are no longer in service. As a matter of equity, we believe that ratepayers should pay only for those assets that currently serve them. TURN's proposal fails this test.

Although TURN's proposal is flawed, TURN argues that the accrual method is even worse. TURN's main objection is that the accrual method requires ratepayers to pay for inflation that has not yet occurred. There is some merit to TURN's objection. TURN has shown that the accrual method front loads removal costs in terms of real dollars. On the other hand, the Settling Parties have demonstrated with their pole example, *supra*, that the accrual method set forth in SP U-4 (and as implemented by PG&E) results in a conservative projection of future inflation that probably understates future removal costs in nominal dollars. The understatement of future removal costs offsets, at least in part, the front loading of future removal costs in terms of real dollars.

TURN also objects to the accrual method because it relies on 30-year projections of future removal costs that will likely prove to be inaccurate, and thereby result in current ratepayers paying more or less than they should. TURN is undoubtedly correct, but its objection also applies to other elements of depreciation expense, including service lives, as SP U-4 explicitly recognizes.²³⁸ Indeed, TURN's objection applies to most elements of future test-year ratemaking. We conclude that because we endeavor to use reasonable assumptions to determine depreciation expense, including removal costs, and because we update these assumptions in every GRC proceeding, our use of

²³⁸ Exhibit PG&E-54, pp. 7-8.

projected future removal costs for ratemaking purposes is not unfair to current ratepayers. Moreover, because SP U-4 tends to understate future removal costs for the reasons described previously, it is unlikely that ratepayers will pay too much for future removal costs in terms of nominal dollars.

Next, TURN argues that the following sentence in SP U-4 shows that the Commission did not intend for removal costs to include future levels of inflation:

Predicted future cost of removal should be based on a reasonable projection of **recent experience** reflecting anticipated changes in labor costs **for the immediate future**. (Exhibit PG&E-54, SP U-4, p. 40. Emphasis added.)

Parenthesis We find that TURN's interpretation of SP U-4 is not supported by the tables in SP U-4 which illustrate what was intended by this statement. The record shows that PG&E calculated future removal costs in conformity with the detailed instructions and illustrative tables set forth in SP U-4.²³⁹

For the preceding reasons, we are not persuaded that there is a need to abandon our long-held practice of using SP U-4 to determine the removal cost component of depreciation expense. Although we will retain our current practice for the time being, we are concerned about the large and growing balance of pre-funded removal costs, which currently exceeds \$2.1 billion. We encourage TURN, DRA, and the others to carefully analyze pre-funded removal costs in the next GRC proceeding. To aid in this analysis, we will require PG&E to provide the following information in its next GRC proceeding:

- The then-current balance of pre-funded removal costs.

²³⁹ Compare Exhibit PG&E-54, pp. 37-39 with Exhibit PG&E-2 WP10, pp. 10-8, 10-16, 10-23, and 10-30.

- A year-by-year projection of (1) when the then-existing balance of pre-funded removal costs will be consumed, and (2) the implicit inflation rate for future asset removal costs.
- A five-year projection of the year-end balance of pre-funded removal costs showing for each year the gross additions to the balance, gross expenditures for removal costs, and the net change in the balance of pre-funded removal costs.

iii. Net Present Value Depreciation Study

(A) Position of the Parties

(1) TURN

TURN argues that the traditional accrual method for recovering future removal costs is flawed because it is based on nominal dollars instead of real dollars. To correct this perceived flaw, TURN recommends that PG&E provide in its next GRC an estimate of future removal costs using the net-present-value approach described in SFAS 143.

TURN states that its recommendation is consistent with the Commission's decision in the recent SCE GRC proceeding. There, the Commission ordered SCE to provide in its next GRC a depreciation study that includes (1) a detailed analysis justifying the reasonableness of applying the method proposed at that time by SCE for determining removal costs, (2) an analysis of the effects of past inflation on SCE's proposed cost of removal rates, and (3) a justification of the implicit inflation rates reflected in SCE's proposed removal rates.²⁴⁰

TURN believes that its recommendation is consistent with two accounting pronouncements: SFAS 143 and FASB Interpretation No. 47 (FIN 47). Together, these two pronouncements require PG&E to report on its external financial

²⁴⁰ D.06-05-016, *mimeo.*, pp. 205-210 and COL 33.

statements the “fair value” of PG&E’s legal obligation to incur future removal costs.²⁴¹ These legal obligations are referred to as “asset retirement obligations” (AROs) and constitute only a fraction of PG&E’s estimated future removal costs. In general terms, the fair value of AROs is the current market value of future removal costs or, when market value cannot be ascertained, the present value of future removal costs. PG&E used the present-value approach for its AROs.

TURN asserts that SFAS 143 and FIN 47 demonstrate that the accounting profession is moving towards a net present value approach for accruing all future removal costs. TURN also contends that because PG&E has successfully implemented SFAS 143 and FIN 47, PG&E should be able to determine the net present value of all of its future removal costs, not just the AROs that are the subject of SFAS 143 and FIN 47.

(2) PG&E and the Other Settling Parties

PG&E opposes TURN’s proposal to require PG&E to submit in its next GRC proceeding a study showing the present value of all future removal costs. PG&E believes the Commission should wait until it has received and reviewed SCE’s study to determine if a similar study is needed for PG&E. If, as PG&E expects, the SCE study shows that the implicit inflation rates are very conservative, there would be no need for PG&E to incur the additional expense of preparing a study.

²⁴¹ SFAS 143 and FIN 47 require PG&E to record an ARO at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset.

PG&E believes the record in the current proceeding shows that the traditional method for projecting future removal costs in SP U-4 understates future inflation and thereby results in a conservative estimate of future removal costs. If the understated removal costs were then discounted back to the present, the result would be a fictional present value that is less than current removal costs. PG&E argues that because such a study would not reflect reality, it would have no use and would be a waste PG&E's and the Commission's resources.

PG&E disputes TURN's suggestion that PG&E's successful implementation of SFAS 143 and FIN 47 shows that PG&E can determine the net present value of all removal costs. PG&E states that SFAS 143 and FIN 47 affected only a handful of accounts, not the entire spectrum of the GRC filing, which would be far more complex and subjective. Unlike SP U-4, which has a long history of interpretation and application, there is no detailed set of rules for determining the net present value of future removal costs. Because PG&E would be preparing the study with little guidance, the result is likely to be controversial.

(3) SCE

SCE asserts that TURN's proposal is inappropriate. This is because the present-value calculation prescribed by SFAS 143 uses the following parameters that are unsuitable for ratemaking: (1) the estimated cost to permanently retire, remove, and/or dispose of tangible assets; (2) estimated escalation rates; (3) a provision for third-party profits; (4) varying future scenarios weighted by the probability of occurrence; and (5) the entity's credit-adjusted risk free rate.

SCE sees three other flaws in TURN's proposal. First, TURN seeks to eliminate the use of nominal cost for only a single component of depreciation – future removal costs. TURN makes no attempt to apply a consistent approach by restating plant, accumulated depreciation, and deferred taxes at current value.

Second, TURN admits that the SFAS 143 calculation is complicated and requires “substantial judgment in the determination of inflation and discount rates.”²⁴² Finally, SP U-4 distinguishes between the “value concept” and the “cost concept.” The first is related to market value, while the latter refers to nominal accounting costs. SP U-4 rejected the value concept for ratemaking purposes.²⁴³ SCE states that SFAS 143 uses a value concept that was rejected by SP U-4.

(B) Discussion

We decline to adopt TURN’s proposal to order PG&E to submit in its next GRC a study showing the net present value of removal costs for all assets using the method set forth in SFAS 143 and FIN 47. We agree with PG&E and SCE that such a study would be complex and controversial. Unless there is a clear need for such a study, we should not require it.

We are not persuaded that there is a need. PG&E has provided persuasive evidence that SP U-4 understates future removal costs in nominal dollars.²⁴⁴ Thus, even though there is no explicit discounting of future removal costs under SP U-4 for the purpose of determining present value, there is an implicit discounting due to the understatement of future removal costs by SP U-4. TURN has not demonstrated that SFAS 143 and FIN 47 would provide results that are materially different from SP U-4.

Our resolution of this matter is consistent with our decision in the recent SCE GRC proceeding. There, we required SCE to provide additional information in its next GRC proceeding to justify the future removal costs determined in

²⁴² Exhibit TURN-3, pp. 48, 51.

²⁴³ SP U-4, p. 5.

²⁴⁴ See summary of evidence in the Settlement Motion at pp. 260-262.

accordance with SP U-4, but we did not require SCE to provide a net present value study of all future removal costs.

If TURN wishes to pursue this matter in the next GRC, we suggest that it consider a narrowly tailored, incremental approach based on GAAP. To this end, TURN may wish to present a side-by-side comparison of (1) removal costs for AROs determined in accordance with GAAP, and (2) removal costs for the same assets determined in accordance with SP U-4. PG&E shall provide to TURN, upon request, the information that TURN may need to make this comparison. Once we have the side-by-side comparison, we will be in a better position to make an informed decision on whether to adopt for regulatory purposes a GAAP-based, net-present-value approach for those removal costs that are classified as AROs under GAAP.

9. Taxes

a. Summary

PG&E presented testimony and forecasts on income taxes, property taxes, and other taxes that PG&E must pay in 2007. The Settling Parties agreed to PG&E's methods for computing taxes.

DRA agreed with PG&E's method for estimating income taxes. In reaching its conclusion, DRA reviewed several items, including recent Federal and State tax law changes; the Federal and State tax deductions for depreciation; Federal and State operating expense adjustments; Federal and State cost-of-removal deductions; Federal and State repair allowance; Federal deduction for State Franchise Taxes; and potential charitable contribution deductions.

TURN raised two concerns about PG&E's computation of income tax expense. First, TURN recommended that if the Commission decides to disallow meal and entertainment expenses, it must also remove the related tax deduction

for the disallowed expenses. PG&E agreed with TURN's proposal, which is reflected in the Comparison Exhibit and the Settlement Agreement revenue requirement. Second, TURN objected to PG&E's treatment of the income tax deduction for dividends paid on PG&E Corporation stock held in the Employee Stock Ownership Plan (ESOP), arguing that the benefit of the deduction should be flowed through to ratepayers. This matter is addressed below.

For property taxes, DRA found the results of PG&E's methodology (as set forth in its Application) reasonable and stated that the differences between DRA's property tax estimate and PG&E's were due to different plant estimates.

Finally, PG&E's forecasts for all other taxes was uncontested, including payroll, business license, federal highway use, and timber yield taxes. DRA, the only party to address these taxes, found that PG&E's method for forecasting these taxes was reasonable.

b. Discussion

PG&E and DRA provided dozens of pages of testimony and work papers regarding the various types of taxes paid by PG&E and the proper method for calculating the different taxes. The record indicates that PG&E and the Settlement Agreement have determined the various taxes in conformance with Commission precedent and all applicable tax laws and regulations.

With the exception of the ESOP, addressed below, we find that the tax amounts adopted by the Settlement Agreement are reasonable in light of the whole record, consistent with applicable law, and in the public interest.

c. Tax Deduction for ESOP Dividends

PG&E's parent company, PG&E Corporation, has an ESOP. Utility employees may invest their money in the ESOP, and the Utility (PG&E) will match 75% of employee contributions up to 6% of their salary. The cost of the

Utility's matching contributions is included in rates. Although PG&E Corp. operates the ESOP, 99.527% of the money in the ESOP relates to contributions from Utility employees and the Utility's matching contributions.

The dividends paid by PG&E Corp. to stock held by the ESOP are tax deductible. The total dividends paid to the ESOP in 2005 was \$30.043 million.

TURN recommends that the tax deduction for dividends paid to the ESOP be flowed through to ratepayers. DRA did not address this issue. PG&E opposes this adjustment. The determination of who should benefit from the tax deduction (ratepayers or shareholders) does not have any consequences for PG&E employees or the benefits they will receive under the ESOP program.

i. Position of the Parties

(A) TURN

TURN estimates that the total dividends paid to the ESOP in 2007 will be \$43.9 million. The RO model used by Settling Parties to calculate PG&E's revenue requirement shows that a tax deduction of \$43.9 million reduces PG&E's GRC revenue requirement by \$29.547 million.

TURN argues that PG&E's shareholders do not provide the funds that generate the tax deduction and, therefore, do not have an equitable right to the deduction. Rather, the deduction exists because PG&E Corp. has an ESOP that is funded largely by ratepayers (i.e., ratepayers paid the wages that fund the workers' contributions to the ESOP and PG&E's matching contributions).

TURN contends that in SCE's recent GRC proceeding the Commission held that the tax benefit belongs to ratepayers. Specifically, in A.04-12-014, SCE assigned to ratepayers the tax deduction for dividends paid to its ESOP. SCE

also agreed that this ratemaking treatment was consistent with Commission precedent.²⁴⁵ The Commission adopted this ratemaking treatment in D.06-05-016. TURN states that the Commission should not adopt divergent treatment for ESOP dividends in two proceedings presenting identical facts.

(B) PG&E and the Other Settling Parties

PG&E responds that the Commission held in D.84-05-036 that tax deductions attributable to management's use of retained earnings belong to shareholders, not ratepayers.²⁴⁶ Since dividends are paid out of retained earnings at the discretion of management, it follows that the tax deduction attributable to these dividends properly belongs to the shareholders.

PG&E explains that after the ratepayers fund employee wages, the employees may invest their pre-tax wages in the Savings Fund Plan, which includes the ESOP. The associated tax benefit is retained by the employees. Ratepayers also fund the Utility's matching contribution, and the tax benefit of the Utility's contribution is flowed through to the ratepayers. PG&E argues that just as the ratepayers cannot claim the tax benefit realized by employees when they contribute pre-tax wages to the Savings Fund Plan, the ratepayers cannot claim the tax deductions realized by shareholders when their retained earnings are used to pay dividends to stock held by the ESOP.

PG&E disagrees with TURN that the recent SCE GRC proceeding establishes an applicable precedent. PG&E represents that the ratemaking treatment of the tax benefit was not litigated or explicitly decided by the Commission. Instead, SCE's application assigned the tax benefit to ratepayers,

²⁴⁵ Exhibit TURN-44.

²⁴⁶ D.84-05-036, 15 CPUC 2d 42 at 48, 49.

which was not contested. PG&E testified that SCE now agrees with PG&E that the tax deduction for dividends paid to an ESOP belongs to shareholders.

ii. Discussion

The Settling Parties represent that they considered TURN's position on ESOPs and, even though the Settlement does not adopt TURN's position, that does not mean TURN's position is not reflected in the Settlement. They state that the ultimate question is not whether any particular issue is adopted or rejected by the Settlement, but whether the Settlement as a whole is reasonable.²⁴⁷ We agree. It is from this perspective that we will evaluate the Settlement outcome for ESOPs.

The Settlement provides PG&E with a revenue increase of \$213 million in 2007 compared to 2006. This is \$181 million less than PG&E's requested increase of \$395 million. The Settlement results in PG&E receiving 53.9% of its post-hearing, pre-settlement litigation position, and provides PG&E with \$600 million less than it requested in cumulative revenues for 2007, 2008, and 2009. Thus, the Settlement represents a significant compromise on PG&E's part.

The question is whether this outcome is reasonable in light of the whole record regarding the issues raised by TURN, including ESOPs. We find that it is. Previously in today's Opinion, we reviewed the record for all the issues still contested by TURN, and we find in all instances that the Settlement outcome for these issues is reasonable. In fact, we find the largest disallowances proposed by TURN other than ESOPs, such as TURN's proposed disallowance for asset removal costs, are unreasonable.

²⁴⁷ Settling Parties Reply Comments filed October 5, 2006, p. 120.

With this background in mind, we find that it is unnecessary to delve deeper into the merits of TURN's proposed disallowance for ESOP tax benefits. We conclude that the Settlement Agreement, by reducing PG&E's requested revenue requirement by \$181 million, represents a reasonable approximation of the likely litigation outcome of all issues raised by TURN and the other parties, including ESOPs. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to reduce PG&E's revenues by an additional \$29.547 million.

We disagree with TURN's argument that today's Opinion represents a departure from Commission precedent in the SCE GRC proceeding. As PG&E correctly notes, our decision (D.06-05-016) in the SCE GRC proceeding did not explicitly address the ratemaking treatment of ESOPs.

F. Revenue Requirement and Rate Base

1. Results of Operations for 2007

PG&E calculated its GRC revenue requirement and rate base using the results of operations (RO) computer model that consists of thousands of inputs and algorithms. The same RO model was used to compute the Settlement RO, the Comparison Exhibit RO, and the ROs in PG&E's and DRA's filed testimony. The differences in the RO output between the Settlement and the Comparison Exhibit result from different inputs, and not from different modeling algorithms. The Settlement includes an RO for PG&E's aggregate GRC revenue requirement and rate base in 2007, and separate ROs for Electric Distribution, Gas Distribution, and Electric Generation.

Using the RO model, the Settling Parties calculated a total 2007 GRC revenue requirement of \$5.043 billion, comprised of \$2.950 billion for Electric Distribution, \$1.073 billion for Gas Distribution, and \$1.020 billion for Electric

Generation. Subtracting forecasted other operating revenues (OORs) of \$116 million leaves a net revenue requirement of \$4.927 billion in 2007.

Compared to 2006, the Settlement revenue requirement of \$5.043 billion represents an increase of \$237 million, or 4.5%, comprised of \$235 million for Electric Distribution, \$30 million for Gas Distribution, and a decrease of \$28 million for Electric Generation. The overall increase of \$237 million is offset by an increase of \$24 million in other OORs to yield the net increase in billed revenues of \$213 million.

The following table compares the weighted-average rate base for 2007 that was calculated by the RO model for the Settlement with PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Weighted Average Rate Base (\$ millions)							
		Comparison Exhibit			Variances Increase/(Decrease)		
	2006 Authorized	PG&E	DRA	Settlement	Settlement vs. 2006	PG&E vs. Settlement	DRA vs. Settlement
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
Rate Base	12,311	12,746	12,347	12,550	239	(196)	203
Source: Settlement Agreement, Appendix A, Line 36.							

The Settlement allocates the rate base to Electric Distribution, Gas Distribution, and Electric Generation.²⁴⁸

There is no dispute regarding the mechanics of the RO model used by the Settlement Agreement to calculate PG&E's revenue requirement and rate base

²⁴⁸ Settlement Agreement, Appendix G, Table 1-10 (Electric Distribution), Table 2-10 (Gas Distribution), and Table 3-10 (Electric Generation).

for 2007.²⁴⁹ We find that the RO model is reasonable in light of the record and consistent with Commission precedent.

2. Revenue Requirement for Attrition Years

a. Position of the Parties

i. The Settlement Agreement

An attrition rate adjustment (ARA) is an element of the Rate Case Plan that adjusts the utility's revenues in the second and third years of the typical three-year GRC cycle for the purpose of sustaining the utility's earnings at an adequate level.²⁵⁰ For PG&E, the second and third attrition years are 2008 and 2009.

PG&E requested that the Commission determine attrition revenue requirement increases for 2008 and 2009 based on the following:

- Detailed forecasts of capital expenditures.
- Detailed forecasts of O&M expenses for electric generation.
- At least 14 separate indices and union contracts for labor, administrative, and O&M expenses.
- Recovery of \$34.8 million in either 2009 or 2010 for a second refueling outage at Diablo Canyon in 2009.
- Miscellaneous cost changes that become final as a matter of law, such as postage rate changes, franchise fee changes, income tax rate changes, and ad valorem tax changes.
- A reduction in the calculated attrition revenue requirement increases of \$41 million in 2008 and \$56 million in 2009 (for

²⁴⁹ TURN found an error in the way the RO model accounted for rental savings in 2007 from the replacement of fleet rental vehicles with Company-owned vehicles. This error has been corrected in the revenue requirement adopted by today's Opinion.

²⁵⁰ D.00-02-046, *mimeo.*, p. 540, COL 44.

cumulative savings of \$97 million) to reflect estimated net savings from Business Transformation efforts.

PG&E's forecasted attrition revenue requirement increases are shown in the table below. PG&E also requested authority to implement attrition adjustments through advice letter filings in October of the prior year.

DRA agreed with some, but not all, of PG&E's attrition proposal. For the most part, DRA recommended that attrition increases in 2008 and 2009 be determined based on the adopted expenses and plant balances for 2007 escalated by a limited number of factors that have been widely used in prior GRC proceedings for PG&E and other utilities.

The Settlement adopts a four-year GRC cycle that spans 2007 through 2010. The Settling Parties further agree to "fixed-amount" attrition revenue increases for the years 2008, 2009, and 2010. The following table compares the Settlement attrition increases with the litigation positions of PG&E and DRA:

Attrition Revenue Requirement Increases (\$ millions)					
	PG&E	DRA	Settlement	Settlement Increase/(Decrease) Compared to:	
				PG&E	DRA
	(A)	(B)	(C)	(C) - (A)	(C) - (B)
Electric Distribution					
2008	67	52	63	(4)	11
2009	80	61	63	(4)	2
2010	N/A	N/A	63	N/A	N/A
Gas Distribution					
2008	25	18	22	(3)	4
2009	25	18	22	(3)	4
2010	N/A	N/A	22	N/A	N/A
Generation					
2008	50	30	40	(10)	10
2009	75	52	75	0	23
2010	N/A	N/A	5	N/A	N/A
TOTAL (after Transformation Savings)					
2008	143	100	125	(18)	25
2009	180	131	160	(20)	29
2010	N/A	N/A	90	N/A	N/A
Source: Settlement, Appendix E, p. 27, L: 6-9.					

The Settlement provides annual attrition increases of \$125 million in 2008, 2009, and 2010, plus a one-time increase of \$35 million in 2009 for a refueling outage at Diablo Canyon. The reason the attrition increase of \$125 million in 2008 rises to \$160 million in 2009 in the above table is to include \$35 million for the Diablo Canyon refueling outage. In 2010, the attrition increase is reduced from \$160 million to \$125 million to remove the \$35 million, and is reduced from

\$125 million to \$90 million to account for the fact that the \$35 million refueling related increase for 2009 is already built into revenues for 2010.²⁵¹

The total attrition revenues during 2008-2010 sum to \$785 million. This is equal to the cumulative \$125 million-increase-per-year attrition revenues of \$750 million (\$375 million + \$250 million + \$125 million), plus \$35 million for the second Diablo Canyon refueling outage in 2009. The year-over-year increase in billed revenues for base rates is 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010.²⁵² The Settled net additions to rate base and end-of-year plant are shown in the Settlement Agreement, Appendix G, Tables 1-7, 2-7, and 3-7.²⁵³

The attrition revenue increases of \$125 million in 2008 and \$160 million in 2009 are near the mid-points of the ranges between PG&E's and DRA's recommendations for those years. The total amounts shown in the above table for 2008 - 2010 reflect PG&E's proposed reduction in its revenue requirements of \$41 million in 2008 and another \$56 million in 2009 (for a total of \$97 million in 2009) for PG&E's forecast of the net savings from Business Transformation.

The Settling Parties agree that PG&E's next GRC should be deferred by one year, until 2011. As a result, the Settlement provides an attrition increase of \$90 million in 2010 to be implemented through an advice letter filing.²⁵⁴

²⁵¹ If the refueling is postponed from 2009 to 2010, rates in 2009 and 2010 will be adjusted to ensure that ratepayer pay no more than \$35 million in total for the refueling outage. If no refueling occurs, the \$35 million will be refunded.

²⁵² Settlement Agreement, Appendix E, as corrected.

²⁵³ The Settling Parties agreed that an estimated \$8.1 million of projects at the Humboldt Bay Power Plant (HBPP) will be recorded in a balancing account and recouped in the next GRC, if required. The Tables in Appendix G of the Settlement Agreement omit capital expenditures at HBPP.

²⁵⁴ Settlement Agreement, paras. 45-47.

ii. Aglet

Aglet agrees that PG&E should receive attrition increases in 2008 and 2009, and Aglet supports an additional attrition increase of \$35 million for the refueling outage at Diablo Canyon. On the other hand, Aglet states that the Settlement's attrition increases are too generous.

Aglet contends that Settled attrition increases do not properly reflect Business Transformation savings.²⁵⁵ The practical effect of the Settlement, according to Aglet, is to give PG&E an annual increase of \$125 million during 2008-2010, plus an additional increase of \$41 million of Transformation savings in 2008 and \$56 million of savings in 2009. When Transformation savings are added, the net attrition increase is 3.4% in 2008 and 3.6% in 2009.

PG&E did not provide estimated Business Transformation savings for 2010. Aglet estimates the savings in 2010 will be at least \$95 million. These savings, when added to the Settlement's attrition increase of \$125 million for 2010, result in an attrition rate increase of at least 4.2% in 2010.

Aglet maintains that the Settlement attrition increases (3.4% in 2008, 3.6% in 2009, and 4.2% in 2010) are too high in light of Global Insight's forecasted increases in the Consumer Price Index (CPI) of 1.61% in 2008 and 1.48% in 2009. The 2009 increase is higher than PG&E's own forecasts of escalation rates for that year. PG&E forecasted 2009 escalation rates of 3.41% for administrative costs, 3.46% for labor, 0.95% for Electric Generation, and 1.78% for Gas Service. Aglet states that if the Commission does nothing else to revise the Settlement, it should

²⁵⁵ The purpose of PG&E's Business Transformation project is to improve the way the Company does business, with the goal of establishing PG&E as an industry leader in its business processes and customer service.

cap attrition increases, before Business Transformation savings, at PG&E's own forecasted escalation rates.

Aglet's preferred alternative is to modify the Settlement Agreement to replace the fixed-amount attrition increases (other than the fixed amount for Diablo Canyon refueling outage) with attrition increases based on forecast changes to the CPI for Urban Consumers (CPI-U). As noted above, Global Insight has forecasted CPI increases of 1.61% in 2008 and 1.48% in 2009.

Aglet believes that a CPI-based attrition mechanism fairly balances shareholder and ratepayer interests and is consistent with Commission precedent. In the most recent GRC for SCG and SDG&E, the Commission stated, "The most important issue for the [attrition] indexing method is to correctly identify the most appropriate index to reasonably adjust the post-test year revenue requirements.²⁵⁶" The Commission then approved a settlement that relied on CPI forecasts. The Commission concluded, "The CPI is a reasonable indicator of inflation for SCG and SDG&E for the post-test year period until the next GRC.²⁵⁷"

iii. PG&E and the Other Parties

PG&E responds that Aglet has not provided any valid reasons for rejecting the Settlement provisions regarding attrition.

b. Discussion

We find that the Settlement Agreement's attrition increases in 2008, 2009, and 2010 are reasonable in light of the record. PG&E provided extensive and

²⁵⁶ D.05-03-023, *mimeo.*, p. 14.

²⁵⁷ D.05-03-023, *mimeo.*, p. 73, COL 9.

generally persuasive testimony supporting attrition increases in the range of those set forth in the Settlement Agreement. Our main concern with PG&E's attrition proposal is that it used an overly complex methodology that relied on more than a dozen indices and forecasted capital expenditures for hundreds of projects. As such, PG&E's proposal was contrary to the Commission's long-standing policy that attrition adjustments should be simple and non-controversial.²⁵⁸ The Settlement Agreement, by adopting a fixed-amount attrition increases, complies with the Commission's policy.

Aglet's claim that the Settlement's attrition increases are "too generous" misconstrues the role that PG&E's forecasted Transformation savings play in calculating the Settled attrition increases. Aglet treats the forecasted savings as if they are additional payments from customers, adds them to the Settled attrition increases to develop higher attrition figures, and then concludes that the Settled attrition amounts are too high. In reality, the Transformation savings are not a stealthy attrition rate increase as Aglet seems to imply. PG&E's ratepayers will not pay a penny more for attrition increases than the fixed amounts explicitly set forth in the Settlement Agreement.

We decline to adopt Aglet's recommendation to cap attrition increases, before Business Transformation savings, at PG&E's own escalation rates. As shown in the previous table, PG&E's attrition proposal (which includes its escalation rates and transformation savings) results in higher attrition increases in 2008 and 2009 than the Settlement Agreement adopted by today's Opinion. Thus, adopting Aglet's recommendation would produce larger attrition increases

²⁵⁸ See, for example, D.02-02-043, 202 Cal. PUC LEXIS 168, *9.

than the Settlement Agreement. Moreover, PG&E's escalation rates set forth in Exhibit PG&E-8, Chapter 3, are not meant to apply to major cost drivers such as rate base additions and rapidly rising health care costs. Consequently, it would be inappropriate to determine attrition increases using only PG&E's escalation rates as Aglet proposes.

Turning to Aglet's proposal to base attrition increases on the CPI, we generally agree with Aglet that a CPI-based approach is relatively easy to implement, consistent with Commission precedent, and is fair to the utility and ratepayers. However, it is unnecessary to adopt Aglet's proposal here. The fixed-amount attrition increases in the Settlement Agreement are supported by the record, easy to implement, and reasonable when compared to the CPI. Excluding costs for the Diablo Canyon refueling outage in 2009, the attrition increases under the Settlement are 2.5% in 2008, 2.5% in 2009, and 2.4% in 2010.

By comparison, the annual CPI grew at an annual average of 2.5% during 1990-2005 and the utility-specific index grew at 3.2%.²⁵⁹ Aglet also provided a State of California forecast that shows the California-specific CPI increasing by 3.2% from June 2007 to June 2008 and by 3.0% from June 2008 to June 2009.²⁶⁰ Thus, the percentage attrition increases in the Settlement are on par with the historic CPI, less than the utility-specific cost index over the past 15 years, and lower than the forecast for the California CPI in 2008 and 2009. This comparison evidences the reasonableness of the Settled attrition increases.

For the preceding reasons, we find the Settlement provisions on attrition are reasonable in light of the record, consistent with the law, and in the public

²⁵⁹ Settlement Motion, p. 310.

²⁶⁰ Aglet Comments on the Settlement Agreement, Attachment, p. 45.

interest, and provide sufficient information to enable the Commission to easily implement attrition adjustments in accordance with the terms of the Settlement.

3. Interference with Other Proceedings

a. Position of the Parties

Aglet opposes a third attrition year in 2010 because a PG&E rate case for test-year 2011 would overlap with the GRCs for SDG&E and SCG (together, Sempra). Under the current rate case plan, Sempra will file rate cases for test-years 2008 and 2011. If PG&E's next rate case is pushed to a 2011 test year, it would coincide with Sempra's GRC. Aglet contends that concurrent litigation of two major GRCs is not practical for DRA, Aglet, and TURN.

PG&E believes that Aglet's concern about concurrent GRCs is unlikely to materialize. In August 2006, SDG&E and SCG each tendered an NOI for a 2008 test-year GRC. Both companies seek a five-year attrition period running from 2009 through 2013.²⁶¹ Acceptance of their proposal would move the next GRCs for SDG&E and SCG to a 2014 test year, thereby eliminating any overlap with a 2011 test-year GRC for PG&E.

b. Discussion

Aglet asks the Commission to reject the Settlement's provision for a third attrition year in 2010 to avoid concurrent GRC proceedings for PG&E and Sempra in 2011. We find that Aglet's concern is hypothetical at this point for the reasons cited by PG&E and, therefore, does not justify denial of the Settlement's provision for a third attrition year in 2010.²⁶² Even if the Commission does not

²⁶¹ SDG&E NOI, p. 8; SoCalGas NOI, p. 2.

²⁶² If history is a guide, the 2010 attrition increase authorized by today's Opinion is likely less than what PG&E would seek in a 2010 test-year GRC application.

adopt Sempra's proposal for a five-year GRC cycle (which would cause the next Sempra GRC to overlap with PG&E's 2011 test year GRC adopted herein), this would not be the first time the Commission has conducted two major GRC proceedings in a single year. For example, the Commission concurrently processed test-year 2003 GRCs for PG&E and SCE. The Commission has the resources to do so again.²⁶³ With proper planning and cooperation among the major parties, we believe that intervenors should be able to handle two concurrent GRCs as well.

4. PG&E Financial Health

a. Position of the Parties

Aglet recommends that the Commission find that granting PG&E all of its test year and attrition year requests is not necessary for PG&E to maintain the financial health it requires to provide adequate utility service. Aglet's makes its recommendation in response to PG&E's testimony that granting all of its request is "critical to providing PG&E sufficient revenues to continue providing safe and reliable service to customers, while providing PG&E a reasonable opportunity to earn its rate of return."²⁶⁴

Aglet believes the Commission should view this GRC in the context of PG&E's financial condition, which is very good. PG&E has investment grade credit ratings. In 2005, total return to shareholders exceeded 15%. During the same year, PG&E Corporation had enough cash to repurchase \$2.2 billion of

²⁶³ DRA does not share Aglet's concerns about concurrent GRC proceedings. (Settling Parties reply comments, p. 15.)

²⁶⁴ Exhibit PG&E-9, p. 1-1.

common stock. The trend of PG&E's ROE is improving, reaching 10.6% in 2004 despite an increase in its equity ratio to 52%.

Aglet states that the *sine qua non* of financial health is strong cash flows, which PG&E has in spades. PG&E Corporation's common stock dividend is \$1.32 per share, up 10% over 2004 levels. PG&E Corporation has set a target to grow earnings per share at an average annual rate of 7.5% through 2010. Standard & Poor's expects PG&E "to produce financial results that provide a cushion sufficient to support sound credit quality."²⁶⁵

Aglet agrees with Standard & Poor's that PG&E has sound credit quality. Aglet reviewed PG&E projected income statements, balance sheets, cash flows, and other ratemaking information.²⁶⁶ Based on its review, Aglet believes that PG&E's financial metrics will remain strong.

PG&E observes that, by necessity, it must operate within the revenues set by the Commission because it has no other source of revenue. PG&E also posits that it will remain financially healthy only if its capital expenditures are allowed into rate base and authorized revenues support the required level of investment.

b. Discussion

We agree with Aglet that PG&E is financially healthy. PG&E does not need all of the test-year and attrition year revenues it requested in A.05-12-002 to maintain the financial health that PG&E requires to provide good, safe, and reliable service. This is demonstrated by the fact that the Settlement Agreement provides less revenue to PG&E than it requested in A.05-12-002. Obviously,

²⁶⁵ Exhibit Aglet-2, p. 49.

²⁶⁶ Exhibit Aglet-9C, confidential calculations by PG&E, pp. 4-5. See also Standard & Poor's credit ratio guidelines, Exhibit Aglet 5-C, pp. 3-4.

PG&E would not have settled for less revenue if it believed that doing so would harm its financial health.

5. Vacancies

a. Position of the Parties

TURN believes the Settlement Agreement reflects the unrealistic assumption that PG&E will have zero employee vacancies at all times. TURN recommends that the Commission reduce PG&E's forecasted labor expenses by \$10.5 million in 2004 dollars to reflect a 1% vacancy rate.

TURN represents that PG&E did not provide the number of employees or vacancies for the 2007 test year. Nor did PG&E provide a forecast of test year labor expenses for straight time versus overtime. As a result, TURN found it impossible to evaluate whether the people that PG&E is adding to fill vacancies reduces overtime costs. To aid future analysis, TURN asks the Commission to require PG&E to provide forecasted and actual staffing levels in its next GRC.

PG&E opposes TURN's recommendation. PG&E states that TURN erroneously assumes that PG&E's forecast of labor costs was based on the number of employees available to perform the work. PG&E represents that it forecasted the amount of work that needs to be done and the cost of that work. To extent PG&E has vacant positions, PG&E intends to use overtime, temporary employees, and contractors to perform the needed work.

b. Discussion

We decline to adopt TURN's proposal to reduce PG&E's revenue requirement by \$10.5 million to reflect a 1% personnel vacancy rate. The fact that PG&E has vacancies does not support an inference that PG&E will have lower labor costs than set forth in the Settlement Agreement. To the contrary, the

record demonstrates that vacancies will not reduce PG&E's costs, since PG&E will backfill the vacancies with overtime, temporary help, and contractors.

For example, PG&E witness Burns testified that only 145 out of 160 budgeted positions in 2006 are staffed in the Electric Supply Administration department. However, the same witness also testified that the department was in the process of filling the vacancies, that staff was working significant overtime (without overtime pay) to fulfill workload objectives, that consultants are hired to meet short-term gaps, and that some work is not being done or being done in a less thorough manner.²⁶⁷ PG&E's other witnesses provided similar responses to cross examination by TURN.²⁶⁸ We do not believe it is in the public interest to overwork employees or to have needed work go undone. PG&E should be allowed to recover costs based on a reasonable forecast of the work to be done by an appropriate number of employees working a normal schedule.

We agree with TURN that PG&E should provide more information in its next GRC regarding forecasted staffing levels. Labor costs are one of PG&E's largest expenses and need to be carefully reviewed in GRC proceedings. TURN represents, however, that PG&E was unable to provide sufficient information for TURN to analyze whether filling vacancies reduces overtime costs. We appreciate TURN's efforts to review PG&E's labor costs. To aid TURN's efforts in the future, we will require PG&E to provide in its next GRC a forecast of labor costs for A&G Study departments and all other office-based departments, broken down by budgeted positions, filled positions (or vacancy rate), straight time,

²⁶⁷ 14 RT 1048-49, PG&E/Burns.

²⁶⁸ See, for example, Exhibit PG&E-18, p. 1-3, L:23 to p. 1-4, L: 23; Exhibit PG&E-18, pp. 47-2 to 47-3; TR 667:25 - 668:17, PG&E/Smith; and TR 1463:9-11, PG&E/Orsaba.

paid overtime, temporary labor, and outside contractors. We decline to apply this requirement to operating departments whose work is performed in the field. As noted by PG&E in its comments on the Alternate Proposed Decision, the forecast of costs for “field departments” is driven by the work to be done and the unit cost of the work, and not by forecasts of the number of employees needed to perform the work. Consequently, PG&E does not prepare, and we do not need, forecasts of labor costs for field departments at the same level of detail as for A&G Study departments and other office-based departments.

G. General Report Items and Other Miscellaneous Matters

PG&E’s testimony and the Settlement Motion included so-called General Report Items that consist of assorted matters. Several of the General Report items are addressed in other parts of today’s Opinion (e.g., issues raised by Greenlining). The remaining salient General Report Items and other miscellaneous matters are addressed below.

1. Escalation Rates

PG&E proposed escalation rates for most labor and benefit costs and certain non-labor costs based on data from Global Insight. DRA concurred with PG&E’s escalation rates. No other party addressed this matter.

We find PG&E’s escalation rates to be reasonable. We conclude that PG&E’s escalation rates, when combined with other factors driving up PG&E’s costs (e.g., rate base additions and rapidly rising health care costs) support the stipulated revenue requirement increases in the Settlement Agreement.

2. Productivity

California energy utilities are required by D.86-12-095 to provide reports on historic and forecasted productivity growth. As required by D.86-12-095, PG&E’s testimony included a Total Factor Productivity (TFP) analysis.

Depending on the metric, PG&E forecasted TFP in the range of 1% to 2% in 2007. DRA concurred with PG&E's TFP analysis. No other party addressed this topic.

We find that PG&E's TFP analysis complies with D.86-12-095 and the results of the analysis are reasonable and adequately supported. We conclude that PG&E's fairly low rate of TFP growth (which is typical for gas and electric utilities) lends general support to the stipulated revenue requirement increases in the Settlement Agreement.

3. Mission Substation

D.06-02-003 adopted a settlement agreement that resolves issues associated with a fire at PG&E's Mission Substation in San Francisco. The settlement requires PG&E to pay \$6.5 million from shareholder funds, with \$6.0 million to be used to improve safety and reliability in San Francisco, and the remaining \$500,000 to be paid to the State's General Fund. The decision also requires PG&E to "provide, in its next GRC...an accounting of the...\$6.5 million expenditure."

To comply with this requirement, PG&E submitted Exhibit PG&E-24 in the instant GRC proceeding. In its exhibit, PG&E represents that although not all of the transactions called required by D.06-02-003 have occurred, PG&E is (1) recording all of the \$6.5 million in the below-the-line Account 426.5, and (2) creating a reserve for the entire \$6.5 million. When expenditures are made for the transactions described in the settlement, the costs will be charged to the reserve and not to an above-the-line account. PG&E further represents that none of the expenditures were included in its forecasts for the 2007 GRC and none will be reflected in any future GRC.

No party raised any issues regarding this matter. Based on the foregoing, we find that PG&E has complied with the requirements of D.06-02-003.

4. MOU re: Operations Affecting Disabled Persons

Disability Rights Advocates (DIRA) raised several issues regarding the impact of PG&E's operations on people with vision and mobility disabilities. On June 27, 2006, PG&E and DIRA submitted a Memorandum of Understanding (MOU) that resolves those issues raised by DIRA that are not related to the closure of front counters.²⁶⁹ The MOU is contained in Attachment A of today's Opinion. The Settlement Agreement incorporates the MOU, including the additional costs and capital expenditures set forth in the MOU. There is no opposition to the MOU.

The MOU specifies the steps that PG&E will take to ensure that its local offices and pay stations are accessible to persons with mobility and vision disabilities (referred to hereafter as "disabled persons"). PG&E agrees that, with limited exceptions defined in the MOU, its entire network of authorized pay centers will be accessible to disabled persons.

The MOU also provides that PG&E will work with DIRA to complete new protocols to ensure access and safety around its construction projects in the pedestrian right of way for disabled persons. PG&E will retain a consultant to help PG&E implement the new protocols and to review compliance with the protocols during the first year of implementation.

PG&E does not know how many of its utility poles might impede the path of travel for disabled persons. The MOU provides that during 2007, PG&E's contractors who inspect utility poles in certain metropolitan areas as part of the pole test & treat program will measure the clearance between the pole and the edge of the sidewalk where it appears, based on a visual inspection, the pole may

²⁶⁹ The MOU is contained in Exhibit PG&E-71.

impede access on the sidewalk. PG&E and DIRA agree to meet and confer on data collected during 2007 to discuss whether further Commission proceedings or other actions are needed to address any barriers noted in the survey.

The MOU increases PG&E's forecast of expenses and capital expenditures for 2007 as set forth in the following table:

<u>Activity</u>	<u>2007 Expense Increase</u>	<u>2007 Capital Increase</u>
New protocols for temporary construction	\$1,900,000	1,400,000
Survey of utility poles	\$142,000	N/A
TOTAL	\$2,042,000	\$1,400,000

Of the \$2.042 million for increased expenses, \$1.862 million is for one-time costs in 2007 and \$0.180 million is for recurring costs in 2007, 2008 and 2009. The amounts shown in the above table are subsumed in the Settlement outcome for GRC revenues and rate base.

a. Discussion

We find the MOU is reasonable in light of the record and in the public interest because it requires PG&E, at a nominal cost to ratepayers, to (1) maintain and improve access to its local offices and pay stations by disabled persons; (2) enhance safe passage around PG&E's construction sites by disabled persons; and (3) determine the extent utility poles impede access to sidewalks and public rights of way by disabled persons. The MOU is consistent with the law because it promotes compliance with federal and state laws that protect the rights of people with disabilities to full and equal access to governmental programs,

services and activities, and places of public accommodation.²⁷⁰ As required by Commission precedent, there is sufficient information in the MOU to enable the Commission to implement and enforce the terms of the MOU.

5. Performance Incentive Mechanism

PG&E proposed a performance incentive mechanism (PIM) whereby PG&E would receive financial rewards and penalties based on various measures of service quality. The Assigned Commissioner's Ruling and Scoping Memo dated February 3, 2006, deferred PIM issues to Phase 2 of this proceeding.

The Settling Parties agree that PG&E will withdraw its PIM proposal and that no further action should be taken on PIM. There is no opposition to the Settlement outcome for this matter. We concur with this outcome.

VI. Approval of the Settlement

Rule 12.1 requires every settlement, whether contested or not, to be reasonable in light of the whole record, consistent with the law, and in the public interest. Contested settlements are subject to additional scrutiny to ensure that the contested elements of the settlement fairly balance the interests at stake, are consistent with Commission policy objectives, and comply with Rule 12.1.

A. Reasonable in Light of the Whole Record

In today's Opinion, *supra*, we have reviewed the evidentiary record regarding (1) every element of PG&E's requested revenue requirement for 2007 through 2010, and (2) every issue raised by PG&E, DRA, Aglet, ANR/SC, TURN,

²⁷⁰ These laws include Cal. Gov. Code §§ 4450, and 11135 *et seq.*, Cal. Civ. Code §§ 51 *et seq.*, and 54 *et seq.*; the ADA, 42 U.S.C. § 12101 *et seq.*, and Section 504 of the Rehabilitation Act of 1973, 29 U.S.C. § 794; and D.06-04-070, where the Commission ordered utilities to "maintain rights of way or alternative paths of travel" when working in the public rights of way. (D.06-04-070, OP 3.)

and others. Based on our exhaustive review of the record, we conclude that the Settlement is reasonable in light of the whole record. We also find that the Settlement Agreement provides sufficient information to enable the Commission to implement the provisions, terms, and conditions of the Settlement.

The Settlement Agreement is supported by a lengthy, comprehensive, and detailed record. Because the Settlement was reached after the conclusion of 25 days of evidentiary hearings, the formal evidentiary record is complete and has been thoroughly tested through sworn testimony and cross-examination. The Settlement is further supported by the Settling Parties' 323-page Motion to approve the Settlement and the lengthy comments and reply comments on the Settlement Agreement, which together address every issue (with the exception of issues raised by Greenlining).

In its comments on the Alternate Proposed Decision, TURN argues that today's Opinion has applied the wrong burden of proof in deciding contested issues. TURN argues that Commission precedent requires utilities to affirmatively demonstrate the reasonableness of all aspects of their application. Today's Opinion fails this test, according to TURN, because it reviews each contested issue for the sole purpose of determining whether the Settlement as a whole is reasonable in light of the entire record, consistent with the law, and in the public interest. TURN argues that this unfairly shifts the burden of proof to intervenors because it forces them to demonstrate that the entire bundle of outcomes is unreasonable, rather than forcing PG&E to demonstrate that every element of the Settlement is reasonable.

We disagree with TURN's reading of Commission precedent. The standard of review for every settlement, contested or not, is set forth in Rule 12.1. This Rule requires the Commission to evaluate a settlement as a whole. That is

exactly what we have done in today's Opinion. It is PG&E's burden to affirmatively demonstrate with clear and convincing evidence that the Settlement Agreement satisfies Rule 12.1. After reviewing the record for every contested issue, we find that PG&E has met its burden of proof with respect to the Settlement as a whole.

A major factor in determining whether a contested settlement is reasonable is the extent to which the settlement is supported by parties representing the affected interests.²⁷¹ The Settlement Agreement satisfies this requirement. DRA supports the Settlement in the interest of all public utility customers pursuant to its authority under § 309.5(a). PG&E supports the Settlement in the interest of its shareholders. CCUE supports the Settlement in the interest of PG&E's union employees. The Irrigation Districts, DIRA, WMA, CFBF, SCE, SDG&E, and SCG each support certain provisions of the Settlement in the interests of their particular constituencies. Of the 112 witnesses who submitted testimony, 106 were sponsored by the Settling Parties.

The Settlement Agreement represents a fair compromise of the Settling Parties' positions and interests. PG&E has demonstrated that much of its requested increase in billed revenues is reasonable. On the other hand, DRA and other parties have shown that not all of PG&E's request is reasonable. In light of this record, PG&E has agreed to accept approximately \$634 million less than it requested in cumulative billed revenues during 2007, 2008, and 2009 (before the modifications adopted by today's Opinion).²⁷² PG&E's ratepayers, as

²⁷¹ D.04-12-015, 2004 Cal. PUC LEXIS 574, *66.

²⁷² Settlement Agreement, Appendices A and E, show that PG&E agreed to accept revenue increases that were less than its request by \$181 million in 2007, 18 million

Footnote continued on next page.

represented by DRA, have agreed to accept approximately \$623 million more than recommended by DRA in cumulative revenues during 2007 – 2009.²⁷³ Thus, the cumulative increase in revenues adopted by the Settlement for 2007-2009 is roughly half way between PG&E's and DRA's litigation positions. Although no party took a position on PG&E's revenue requirement for 2010, the Settlement's increase of \$125 million for 2010 is consistent with prior years.

Compared to the immediately preceding year, the Settlement increases PG&E's GRC billed revenues by 4.51% in 2007, 2.54% in 2008, 3.17% in 2009, and 1.73% in 2010. These figures include \$35 million for the Diablo Canyon refueling outage. Of course, PG&E's overall revenue requirement is much larger than its GRC revenue requirement. At one point in 2006, PG&E's total Commission-authorized revenue requirement was approximately \$15.481 billion.²⁷⁴ The Settlement increases PG&E's total billed revenues by 1.37% in 2007, 0.80% in 2008, 1.01% in 2009, and 0.56% in 2010. The average annual increase in total billed revenues for the four-year period 2007-2010 under the Settlement is 0.9%.

Aglet, ANR/SC, and TURN oppose the Settlement outcome for certain issues. We have reviewed the record for every issue still contested by Aglet,

in 2008, and \$55 million in 2009. The cumulative amount during 2007 – 2009 = \$634 million = (3 x \$181 million) + (2 x \$18 million) + \$55 million. These figures exclude \$35 million for the Diablo Canyon refueling outage.

²⁷³ The Settlement Agreement, Appendices A and E, show that DRA agreed to accept revenue increases that exceeded its recommendation by \$193 million in 2007 and \$25 million in 2008, and was \$6 million less than DRA's recommendation for 2009. The cumulative amount during 2007 – 2009 = \$623 million = (3 x \$193 million) + (2 x \$25 million) – 6 million.

²⁷⁴ Resolution E-3956, p. 2, Advice 2706-E-A, p. 9, Table 2, Line 38; Advice 2723-G, Attachment 1, p. 2.

ANR/SC, and TURN. We find the Settlement outcome for all of these issues is supported by the record.

Finally, today's Opinion adopts several accounting and reporting requirements that are beyond the scope of the Settlement Agreement. Perhaps the most significant is the requirement for PG&E to record in its regulatory books a regulatory liability for its pre-funded asset removal costs, which totaled \$2.1 billion at the end of 2005. This requirement, which has no financial impact on PG&E, is in the public interest because it helps to ensure that PG&E will only use these funds for their intended purpose of paying for future asset removal costs. Conversely, it would be contrary to ratepayers' interests and Commission precedent if we did not require PG&E to record a regulatory asset.

The other requirements adopted by today's Opinion are listed below. Most of the items are not addressed explicitly by the Settlement Agreement, but are additional requirements that we deem necessary to ensure that the Settlement is reasonable in light of the record and in the public interest.

Additional Requirements Outside the Settlement

- We make it explicit that the cost of the new service guarantee that pays \$100 to customers whose service is wrongly shut off will be borne by PG&E.
- PG&E shall report in its next GRC the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and provide a forecast of future OR and OFA costs based on its actual payment history.
- PG&E shall submit an application in 2011 on whether it is economically feasible and in the best interests of ratepayers to pursue the renewal of the Diablo Canyon operating licenses.
- PG&E shall track expenditures for membership dues in organizations that engage in political activities, including the organizations identified by TURN in this proceeding, and record

an appropriate proportion of these expenditures in the below-the-line Account 426.4.

- The report that on PBOP contributions that PG&E is required to submit at the end of the 2007 GRC cycle pursuant to the paragraph 32 of the Settlement Agreement shall state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.
- In its next GRC, PG&E shall provide the following reports and information:
 - o Revised DA fees that reflect then-current costs and supporting workpapers.
 - o A separate, cost-based NSF flat fee for each of the major customer classes and supporting work papers.
 - o A report that demonstrates that (a) PG&E has reduced its reduce rate base by the actual salvage value on the existing airplane, (b) the depreciation expense for the new airplane is based on a 13-year service life.
 - o A working cash calculation that reflects a lag for PG&E's matching savings-fund contributions in a manner consistent with today's Opinion.
 - o Information regarding asset removal costs that includes: (1) the then current balance of pre-funded removal costs; (2) a year-by-year projection of (a) when the then-existing balance of pre-funded removal costs will be consumed, and (b) the implicit inflation rate for asset removal costs for each future year; and (3) a five-year projection of the year-end balance of pre-funded removal costs showing for each year the gross additions to the balance, gross expenditures for removal costs, and the net change in the balance.
 - o A forecast of labor costs for A&G Study departments and other office-based departments broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

- o Upon request, such information as TURN may need to prepare a side-by-side comparison of asset removal costs for AROs determined in accordance with GAAP and SP U-4.

None of the requirements listed above is a modification of the Settlement. All are reporting requirements or other requirements for the next GRC, plus an accounting change.

B. Consistent with the Law

Aglet, ANR/SC, and TURN argue that the Settlement outcome for several issues is inconsistent with Commission precedent or other applicable legal requirements. We have carefully reviewed their arguments, *supra*. Based on our review, we find that the Settlement Agreement is consistent with the law.

C. The Public Interest

We find that the Settlement Agreement, supplemented by the additional reporting and other requirements listed above, is in the public interest because it enables PG&E to provide safe and reliable service at a reasonable cost through 2010. The Settlement does so by (1) setting a GRC revenue requirement that is consistent based on historical expenses, future trends, customer and system growth, and other cost drivers that set forth in the record; and (2) providing PG&E with the financial means to make necessary capital investments in its utility infrastructure and operations.

Equally important, the Settlement resolves numerous issues affecting the public interest that were raised by the parties. These issues include PG&E's provision of billing services for mobile home park owners, access to PG&E's facilities by disabled persons, and the continued operation of PG&E's front counters. The Settlement resolves all these issues in a way that it fair to the affected interests and beneficial to the public at large.

D. Additional Issues Raised by Aglet and TURN

We previously addressed in today's Opinion the numerous issues raised by Aglet, ANR/SC, and TURN regarding the Settlement outcome on individual matters. In addition to these individual issues, Aglet and TURN argue that the Settlement Agreement is not reasonable in light of the record and is not in the public interest. We address Aglet's and TURN's arguments below.

1. Flawed Settlement Process

TURN alleges that the Settling Parties did not provide TURN and Aglet with a meaningful opportunity to participate in settlement negotiations. When TURN and Aglet were invited to join the discussions, the Settling Parties had already settled many of the issues of importance to TURN and Aglet, including issues that had been raised by TURN or Aglet, but no other party.

In our opinion, the lack of Aglet's and TURN's participation in the initial settlement negotiations was unfortunate but does not make the Settlement unreasonable. There is no requirement that all interested parties participate in preliminary discussions. If that were the case, parties might find it difficult to reach settlements, as it is often easier to reach consensus with a few parties first, and then attempt to obtain consensus from a broader array of parties.

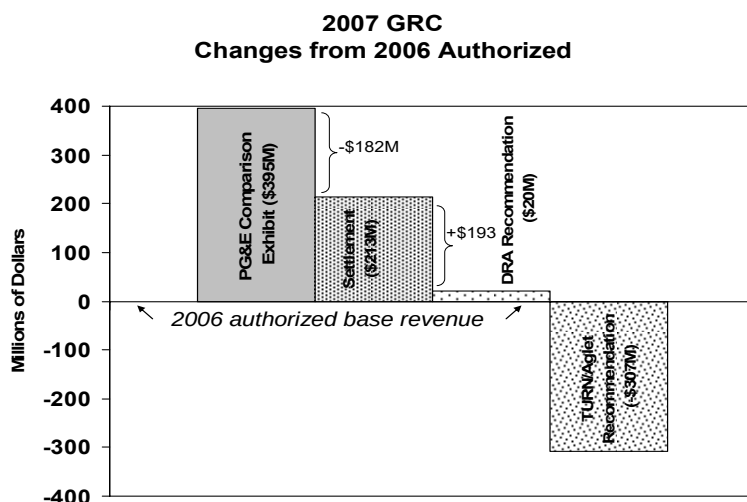
The only requirement regarding settlement participation is set forth in Rule 12.1, which requires the settling parties to hold a settlement conference with notice and opportunity to attend provided to all parties for the purpose of discussing the settlement. The Settling Parties complied with Rule 12.1 by holding a properly noticed settlement conference on August 16, 2006.²⁷⁵

²⁷⁵ After the Settlement was filed, PG&E and DRA held two technical conferences that were noticed and open to the public to answer questions regarding the Settlement.

Footnote continued on next page.

2. Overall Outcome Is Unreasonable

Aglet and TURN argue that the Settlement Agreement is unreasonable in relation to the range of dispute. The following diagram shows the litigation positions of PG&E, DRA, and TURN/ Aglet compared to the Settlement:



As shown in the above diagram , the consolidated TURN/ Aglet position is \$327 million below DRA’s position and \$702 million less than PG&E’s.²⁷⁶

Aglet and TURN each presented quantitative analyses that show the Settlement resolved all of their issues for pennies on the dollar. The low value accorded their issues shows that PG&E did not make any meaningful compromises on the issues they raised. Aglet and TURN believe this outcome is

PG&E also provided written responses to several questions regarding the Settlement.

²⁷⁶ The \$182 million figure in the diagram reflects the amount PG&E agreed to forgo as part of the Settlement, is now \$181 million, due to the fact that D.06-07-027, issued in the AMI proceeding, granted PG&E approximately \$887,000 in costs which were included in this proceeding pending determination of the issue in the AMI case. The \$213 million figure, representing the agreed to increase in revenue requirements over 2006 authorized revenues, does not change.

inconsistent with the strength of their positions, their success in prior GRCs, and the likely result of litigation.

We disagree with Aglet's and TURN's assertion that the Settlement is unreasonable because it places a low value on the issues they raised. The relevant test is whether the outcome is reasonable in light of the whole record. We have carefully reviewed the record for every issue still contested by Aglet and TURN. We find the Settlement outcome for all of these issues is supported by the record.

In their comments on the Alternate Proposed Decision, Aglet and TURN claim that the Settlement is unreasonable because it provides PG&E with a far better outcome compared to the previous GRC. We disagree. DRA observes in its reply comments that the Settlement Agreement provides for an increase of \$213 million in billed revenues for the 2007 Test Year. By contrast, the 2003 GRC increased billed revenues by \$264 million. Thus, the increase provided in the 2007 Settlement Agreement is lower than the 2003 GRC on both a real and nominal dollar basis. The following table shows that the 2007 Settlement also provides PG&E with a smaller percentage increase in its test-year billed revenues compared to the 2003 GRC:

Percentage Increase (Decrease) in Authorized Billed Revenues			
	Electric Distribution	Gas Distribution	Generation
Settlement Agreement: 2007 Test Year *	8.4%	2.0%	(2.9%)
D.04-05-055: 2003 Test Year **	8.5%	4.6%	3.9%
* Source: Settlement Agreement, para. 14. ** Source: D.05-05-055, 2004 Cal. PUC LEXIS 254, *3.			

We conclude for the preceding reasons that there is no merit to Aglet's and TURN's assertion that the Settlement is unreasonable when compared to the prior GRC.

3. No Justification of Outcomes for Individual Issues

Aglet and TURN submit that the Commission must determine whether the Settlement reasonably resolves every issue raised by each party actively involved in the proceeding. Aglet and TURN contend that it is impossible to determine how the Settlement resolves most of the issues they raised. This is because several issues they raised are not addressed by the Settlement Motion or the Settlement Agreement, and the remainder of the issues raised by Aglet and TURN are subsumed in broad Settlement outcomes for expenses and rate base.

In today's Opinion, *supra*, we review the record for every issue still contested by Aglet and TURN and the Settlement outcome for each of these issues. There is ample record to do so. The Settling Parties provided a 323-page Motion that identifies almost all contested issues raised by Aglet and TURN, summarizes the record for each issue, and provides extensive citations to the evidentiary record. The evidentiary record on Aglet's and TURN's issues is voluminous. Aglet and TURN each submitted lengthy comments on the Settlement Agreement that addressed every matter still at issue, including the few issues that were omitted from the Settlement Motion. The Settling Parties' lengthy reply comments likewise addressed those issues that were omitted from the Settlement Motion.

Based on our review of the record, we conclude that the Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Affected Interests Oppose the Settlement

Aglet argues that the Settlement Agreement is unreasonable because it is opposed by residential and small commercial customers who are (1) affected by the Settlement, and (2) represented by Aglet and TURN. Aglet's point has some merit, but it does not support a finding that the Settlement is unreasonable.

Aglet and TURN can only represent their members. In contrast, DRA is authorized by § 309.5(a) to represent all of PG&E's customers, including residential and small commercial customers. While Aglet and TURN oppose the Settlement on behalf of their members, DRA supports the Settlement on behalf of all of PG&E's residential and small commercial customers. For this reason, we conclude that the Settling Parties fairly represent the interests of PG&E's residential and small commercial customers.

E. Conclusion

For all of the previous reasons, we conclude that the Settlement Agreement is reasonable in light of the whole record; fairly balances the affected interests; is consistent with applicable law, Commission precedents, and Commission policies; and is in the public interest. Therefore, we will adopt the Settlement.

In accordance with Rule 12.5, the Settlement Agreement adopted by today's Opinion is binding on all parties. Such adoption does not constitute approval of, or precedent regarding, any principle or issue.

VII. Issued Raised by the Greenlining Institute

The Greenlining Institute (Greenlining) raised a number of issues that were not addressed by the Settlement Agreement, several of which were deemed

to be outside the scope of this proceeding.²⁷⁷ Below, we address only those issues that fall within the scope of this proceeding.

A. Executive Compensation

Greenlining proposed several new reporting requirements regarding executive compensation. In its comments on the Alternate Proposed Decision, Greenlining agreed to drop its proposals in exchange for concessions that were made by PG&E in its comments regarding other issues raised by Greenlining. Consequently, the issues raised by Greenlining regarding executive compensation are moot and are not addressed by today's Opinion.

B. Supplier Diversity, Personnel Diversity, and Philanthropy

Greenlining made numerous recommendations regarding (1) supplier diversity; (2) the diversity of PG&E's Board of Directors, management, and certain segments of PG&E's workforce; and (3) the amount and beneficiaries of PG&E's philanthropy. PG&E opposed Greenlining's recommendations. Subsequently, Greenlining and PG&E reached an agreement on these matters, which is set forth in PG&E's and Greenlining's comments on the Alternate Proposed Decision. The Greenlining-PG&E accord resolves all issues raised by Greenlining. There was no opposition to the accord in the parties' reply comments on the Alternate Proposed Decision.

²⁷⁷ The issues raised by Greenlining that were deemed outside the scope of this proceeding included (i) revisions to PG&E's GO 77-L reports to show CEO compensation next to overall cash philanthropy and/or philanthropy to underserved communities; (ii) the use of nuclear power to reduce dependence on fossil fuels; and (iii) access to the California Solar Initiative program for renters, minorities, and low-income customers. (See Assigned Commissioner's Ruling Clarifying Scoping Memo issued on June 9, 2006.)

The Greenlining-PG&E accord is summarized below. We find the uncontested resolution of the issues raised by Greenlining to be reasonable, consistent with the law and Commission precedent, and in the public interest. Therefore, we will adopt the Greenlining-PG&E accord.

1. Greenlining-PG&E Accord re: Supplier Diversity

In the PG&E-Greenlining accord, PG&E pledges to make a good-faith effort to meet a minority-contract goal of 20% by 2010 or earlier, and to reach the aspirational goal of 27% or better by 2015. To achieve these goals, PG&E pledges to (1) factor in achievement of supplier diversity goals in performance evaluations and compensation; (2) establish a technical assistance program in 2008 for small, minority-owned business; and (3) work with minority-business associations to develop programs to assist small and very small businesses.

2. Greenlining-PG&E Accord re: Board and Management Diversity

PG&E pledges to make a good-faith effort to being a national leader in the diversity of its Board of Directors. This will include a good-faith effort to ensure that the Board includes African-Americans, Latinos, and Asian Americans. PG&E will also make a good-faith effort to set 10-year aspirational goals for management diversity. To this end, PG&E will maintain its current programs that link management evaluations, promotions, and bonuses to the success of management diversity goals.

3. Greenlining-PG&E Accord re: Philanthropy

In a period of just four years, PG&E's cash philanthropy has increased from 0.25% to 1.2% of pre-tax income, and the proportion of PG&E cash philanthropic giving to underserved communities increased from 25% to almost 70%. PG&E pledges to make a good faith effort to maintain this progress.

VIII. Implementation of Today's Opinion

Pursuant to D.06-10-033, the 2007 revenue requirement adopted by today's Opinion is effective as of January 1, 2007. PG&E may collect in rates over the remainder of 2007 the difference between (1) the 2007 revenue requirement authorized by today's Opinion, and (2) the amount actually collected in base rates since January 1, 2007, and prior to the implementation of the revenue requirement adopted herein.

Within 10 days from the effective date of today's Opinion, PG&E shall file an advice letter with revised tariff sheets to implement (1) the revenue requirements authorized by today's Opinion, and (2) all accounting procedures, fees, and charges authorized by today's Opinion that are not addressed in the other advice letters required by today's Opinion. The revised tariff sheets shall (i) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (ii) comply with GO 96-A, and (iii) apply to service rendered on or after their effective date.

IX. Assignment, Categorization, and Need for Hearing

John A. Bohn is the Assigned Commissioner and Timothy Kenney is the assigned ALJ in this proceeding.

In Resolution ALJ 176-3164, dated December 15, 2005, the Commission preliminarily categorized A.05-12-002 as a ratesetting proceeding and preliminarily determined that hearings were necessary. These preliminary determinations were affirmed by the Assigned Commissioner's Ruling and Scoping Memo dated February 3, 2006. There was no appeal of the Ruling.

X. Comments on the Alternate Proposed Decision

The Alternate Proposed Decision of the assigned Commissioner in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and

Rule 14.2. Timely comments were submitted by Aglet, DIRA, DRA, Greenlining, PG&E, SCE, and TURN. Timely reply comments were submitted by Aglet, DRA, Greenlining, PG&E, SCE, TURN, and jointly by the Merced Irrigation District and the Modesto Irrigation District. These comments and reply comments have been reflected, as appropriate, in the final decision adopted by the Commission.

Findings of Fact

1. PG&E's front counters are heavily used. There is a public need for the many types of services and information available at PG&E's front counters.
2. D.04-11-033 required PG&E to present in this GRC proceeding an analysis of the feasibility of offering bill-calculation services to mobile home park (MHP) owners with sub-metered tenants.
3. There is no opposition to the joint proposal submitted by PG&E, TURN, and WMA for PG&E to calculate the gas and electric utility bills for sub-metered tenants of MHPs. The proposal is substantially similar to SCE's MHP bill-calculation service approved by D.06-05-016.
4. The proposed MHP Bill-Calculation Services should benefit MHP owners and tenants, and should not affect PG&E's non-MHP customers in any way.
5. The Settlement Agreement requires PG&E to implement a new service quality standard that pays \$100 to customers whose service is erroneously shut off, but there is no indication of who will bear the cost of the new standard.
6. Since PG&E's current DA fees were established in 1999, PG&E's costs have increased by 17% - 26%, depending on the category of cost.
7. PG&E incurs working-cash costs for bounced checks and recovers these costs through the NSF fee.

8. Compared to a flat fee, an NSF fee that varies by the size of the bounced check would be more costly for PG&E to implement and more confusing to customers.

9. The working-cash costs that PG&E incurs for bounced checks is proportional to the amount of the bounced check. Because the average amount for bounced checks varies by customer class, a uniform flat fee to recover PG&E's costs for bounced checks results in cross-subsidies among customer classes.

10. There is an insufficient record in this proceeding to determine a cost-based NSF flat fee for each customer class.

11. PG&E's requested expenses for its Economic Development program are cost effective under the RIM test.

12. PG&E requested \$5.13 million in 2007 for other regulatory (OR) fees and \$2.757 for FERC Other Federal Agency (OFA) fees. PG&E does not know with certainty whether, and to what extent, it will actually pay OR fees and OFA fees.

13. The current NRC operating licenses for Diablo Canyon expire in 2024 and 2025. It is prudent to know 10 years in advance of license expiration, or by 2014, whether the 2,200 MW of base load capacity provided by Diablo Canyon needs to be replaced so that replacement capacity and associated transmission capacity can be obtained in an orderly, cost effective, and timely manner.

14. PG&E's proposed Diablo Canyon license renewal feasibility will help policy makers reach a final decision by 2014 on whether to proceed with license renewal or, alternatively, begin the process of replacing the power provided by Diablo Canyon prior to the expiration of the operating licenses in 2024 and 2025.

15. AB 1632, which was enacted in 2006, requires the CEC to assess key policy and planning issues regarding the future of Diablo Canyon.

16. PG&E received \$42.8 million in October 2006 from the federal government to settle PG&E's lawsuit over the DOE's failure to build a repository for radioactive waste from nuclear power plants.

17. PG&E improperly recorded above-the-line some of its Chamber of Commerce dues and certain other costs for political lobbying. These costs should have been recorded in the below-the-line Account 426.4.

18. The Settlement Agreement requires PG&E to file at the end of the 2007 GRC cycle a report on the revenue requirement associated with contributions to PG&E's VEBA trusts to fund PBOPs.

19. PG&E has higher medical benefit costs for active employees than SCE. However, PG&E's total compensation is within the range of competitiveness.

20. PG&E has a reasonable need for a replacement Company airplane.

21. The costs to lease and buy a replacement airplane are similar.

22. The Settlement Agreement adopts a lower revenue requirement for the Company airplane than would occur under TURN's proposal to (i) depreciate the replacement plane over 13 years, and (ii) record an estimated salvage value of \$2 million for the current airplane.

23. PG&E's calculation of working cash improperly assumed zero lag days for the Company's matching contributions to the savings fund pool. The effect of PG&E's error was offset in the overall Settlement outcome for rate base.

24. PG&E had \$2.1 billion of pre-funded asset removal costs at the end of 2005, and the balance will grow by \$211 million annually through 2010.

25. D.06-05-016 required SCE to record a regulatory liability for pre-funded asset removal costs.

26. The Settlement attrition increases during 2008, 2009, and 2010 are (i) easy to implement, (ii) supported by PG&E's testimony, and (iii) consistent with

(a) the CPI, (b) utility-specific cost indices over the last 15 years, and (c) the State of California's forecast of the California-specific CPI.

27. Providing PG&E with a third attrition year in 2010 will result in a 2011 test-year GRC for PG&E, which would overlap with the currently scheduled test-year 2011 GRCs for SDG&E and SCG.

28. The Commission and DRA have sufficient resources to process simultaneous test-year 2011 GRCs for PG&E, SDG&E, and SCG.

29. PG&E is financially healthy.

30. Today's Opinion provides PG&E with sufficient revenues to maintain its financial health, to provide good, safe, and reliable utility service, and to make necessary capital investments.

31. D.06-02-003 requires PG&E to present in this GRC proceeding an accounting of the \$6.5 million of payments required by the decision. PG&E did so in Exhibit PG&E-24, which shows that none of the \$6.5 million will ever be charged to ratepayers.

32. The PG&E-DIRA MOU, which is contained in Appendix B of today's Opinion, resolves the issues raised by DIRA concerning the impact of PG&E's operations on disabled persons. There is no opposition to the MOU.

33. Labor costs are one of PG&E's largest expenses and need to be reviewed carefully in GRC proceedings.

34. PG&E was unable to provide sufficient information to enable TURN to analyze whether filling vacant employee positions reduces overtime costs.

35. The Settlement Agreement provides that PG&E will withdraw its performance incentive mechanism (PIM) from consideration in Phase 2 of this proceeding and that no further action should be taken on PIM in this proceeding.

36. The withdrawal of PG&E's PIM proposal leaves front-counter issues as the only remaining topic for Phase 2 of this proceeding.

37. The Settlement Agreement is supported by a comprehensive and detailed record.

38. The Settlement Agreement provides sufficient information to enable the Commission to implement the provisions, terms, and conditions of the Settlement.

39. The Settlement Agreement is supported by parties that fairly represent the affected interests.

40. The Settlement Agreement represents a fair compromise of the Settling Parties' positions and interests.

41. Today's Opinion reviews the record for every issue still contested by Aglet, ANR/SC, and TURN, and the Settlement outcome for each of these issues.

42. The Settlement Agreement erroneously inflates rate base by \$0.624 million for capital expenditures for gas meters and PG&E's revenue requirement by \$0.044 million.

43. PG&E's and Greenlining's comments on the Alternate Proposed Decision resolve all issues raised by Greenlining. The accord, which is summarized in the body of today's Opinion, requires PG&E to make good faith efforts to increase supplier diversity, Board-of-Directors diversity, management diversity, philanthropy, and cash philanthropic gifts to underserved communities.

Conclusions of Law

1. PG&E should not make any significant reductions to the staffing or operations of its front counters without Commission authorization pending the Commission's consideration of front-counter issues in Phase 2 of this proceeding.

2. The MHP Bill-Calculation Services proposed by PG&E, TURN, and WMA should be adopted because the proposal complies with D.04-11-033, is reasonable in light of record, complies with applicable law, and is in the public interest.

3. The rate base in Appendix C shall be reduced by \$0.624 million and the revenue requirement in Appendix C shall be reduced by \$0.044 million.

4. PG&E should file an advice letter (AL) in time to begin offering the Bill-Calculation Services by June 1, 2007. The AL should contain tariffs and a services agreement for the Bill-Calculation Services that are substantially similar to the proposed tariffs and services agreement attached to Exhibit PG&E-70.

5. It is unreasonable for ratepayers as a whole to pay \$100 under the new service quality standard contemplated by the Settlement every time PG&E erroneously shuts off a customer's service. Because it is PG&E's error, PG&E should bear the cost of the new service quality standard.

6. PG&E should include in its next GRC proceeding an up-to-date analysis of its DA fees and costs.

7. To eliminate cross subsidies among customer classes for bounced checks, PG&E should provide in its next GRC proceeding (i) a cost-based NSF flat fee for each of the major customer classes, and (ii) supporting work papers.

8. Section 740.4 allows for rate recovery of utility economic development expenses to the extent of ratepayer benefits.

9. In light of the uncertainty regarding the OR fees and OFA fees that PG&E will ultimately pay, it is reasonable to order PG&E to provide in its next GRC proceeding a report of OR costs and OFA costs paid over the course of this GRC cycle and a forecast of future costs based on its actual payment history.

10. It is in the public interest for PG&E to perform the Diablo Canyon license renewal feasibility study that is described in the body of today's Opinion.

11. PG&E should incorporate into its Diablo Canyon license renewal feasibility study the findings and recommendations from the CEC's assessment of Diablo Canyon conducted pursuant to AB 1632. To this end, PG&E should defer, to the extent feasible, the work on its study, and associated spending, until after the CEC issues its findings and recommendations.

12. PG&E should submit an application by June 30, 2011, on whether renewal the Diablo Canyon operating licenses is cost effective and in the best interest of PG&E's ratepayers. The application should address the matters identified in the body of today's Opinion.

13. Any unused revenue requirement tracked by the HBPP memorandum account should accrue interest at the three-month commercial paper.

14. PG&E is required to flow through to ratepayers the settlement award of \$42.8 million that PG&E received from the DOE, net of costs, in accordance with the procedures applicable to PG&E's DOE Litigation Balancing Account.

15. PG&E failed to comply with long-standing Commission policy and the requirements of the Uniform System of Accounts by not recording in the below-the-line Account 426.4 all Chamber of Commerce dues and certain other expenses for political lobbying or advocacy. PG&E should comply in the future.

16. D.92-12-015 requires that all funds collected by PG&E in rates for contributions to PBOP trusts pursuant to today's Opinion must be used for that purpose or returned to ratepayers.

17. The report that PG&E is required to submit pursuant to the Settlement Agreement at the end of the 2007 GRC cycle regarding its PBOP contributions should state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.

18. In the next GRC, PG&E should reduce rate base by the actual salvage value on the existing airplane and present an appropriate depreciation expense for the replacement airplane based on a 13-year service life.

19. In its next GRC proceeding, PG&E's calculation of working cash should reflect a lag for the Company's matching contributions to the savings fund pool.

20. PG&E should be treated the same as SCE regarding the requirement to record a regulatory liability for pre-funded asset removal costs.

21. PG&E should either use pre-funded asset removal costs (ARCs) for their intended purpose or return these funds to ratepayers.

22. For the reasons set forth in the two previous Conclusions of Law, PG&E should record, for ratemaking purposes, a regulatory liability for pre-funded asset removal costs. The only exception should be pre-funded asset removal costs that are treated by PG&E as Asset Removal Obligations (AROs) under Generally Accepted Accounting Principles (GAAP).

23. PG&E's large and growing balance of pre-funded ARCs requires careful oversight. To this end, PG&E should provide in its next GRC the information regarding ARCs specified in the body of today's Opinion.

24. PG&E should provide to TURN in the next GRC proceeding such information as TURN may reasonably need to compare (i) removal costs for AROs determined in accordance with GAAP, and (ii) removal costs for the same assets determined in accordance with SP U-4.

25. PG&E has complied with the requirements of D.06-02-003.

26. The PG&E-DIRA MOU should be adopted because, for the reasons set forth in the body of today's Opinion, the MOU is reasonable in light of the whole record, consistent with law, and in the public interest.

27. To aid TURN's efforts to analyze PG&E's labor costs, PG&E should provide in its next GRC a forecast of labor costs for A&G Study departments and other office-based departments broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

28. The Settling Parties complied with Rule 12.1 by holding a properly noticed settlement conference on August 16, 2006.

29. The lack of Aglet's and TURN's participation in the initial settlement negotiations does not make the Settlement Agreement unreasonable.

30. The Settlement Agreement is not unreasonable because it places a low value on the issues raised by Aglet and TURN. The test is whether such an outcome is reasonable in light of the whole record. The Settlement Agreement satisfies this test.

31. The Settlement Agreement is reasonable in light of the whole record, including the record for every issue contested by Aglet, ANR/SC, and TURN;

fairly balances the affected interests; is consistent with applicable law, Commission precedents, and Commission policies; and is in the public interest.

32. The motion to adopt the Settlement Agreement should be granted.

33. Except as set forth in the previous Conclusions of Law, the recommendations of Aglet, ANR/SC, TURN, and Greenlining should not be adopted for the reasons set forth in the body of today's Opinion.

34. The accord between PG&E and Greenlining regarding supplier diversity, Board of Directors diversity, management diversity, and corporate philanthropy is reasonable and in the public interest, and should be adopted.

35. Pursuant to D.06-10-033, the 2007 revenue requirement adopted by today's Opinion is effective as of January 1, 2007.

36. Unless otherwise specified herein, PG&E should file all advice letters required by today's Opinion within 30 days. The Energy Division should be authorized to approve all the advice letters filed by PG&E pursuant to today's Opinion without a Commission resolution if such advice letters comply with today's Opinion. Such advice letters should comply with GO 96-A and be subject to a finding of compliance by the Energy Division or its successor.

37. The Settlement Agreement should be corrected to fix an error that erroneously inflates (i) rate base by \$0.624 million for capital expenditures for gas meters, (ii) revenue requirement by \$0.044 million.

38. The following order should be effective immediately so that PG&E's revenue requirement authorized by today's Opinion may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The Settlement Agreement contained in Appendix C of this Order is adopted.
2. Pacific Gas and Electric Company (PG&E) is authorized to recover over the remainder of 2007 the (i) revenue requirement set forth in Appendix C of this Order, less (ii) the amount collected by PG&E in base rates since January 1, 2007, and prior to the implementation of the revenue requirement authorized by this Order, plus (iii) interest on the difference between (i) and (ii), with said interest based on the rate for prime, 3-month commercial paper reported in Federal Reserve Statistical Release H-15.
3. Within 10 days from the effective date of this Order, PG&E shall file an advice letter with revised tariff sheets to implement (i) the revenue requirement authorized by this Order, and (ii) all accounting procedures, fees, and charges authorized by this Order that are not addressed in the other advice letters required by this Order. The revised tariff sheets shall (a) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (b) comply with General Order 96-A, and (c) apply to service rendered on or after their effective date.
4. PG&E is authorized to implement and recover in 2008 through 2010 the annual attrition increases set forth in paragraph 47 of the Settlement Agreement. The attrition increases may be implemented by advice letter as set forth in paragraph 46 of the Settlement Agreement.
5. PG&E shall not make significant reductions to the staffing or operations of its 84 front counters without Commission authorization pending the Commission's consideration of front-counter issues in Phase 2 of this proceeding.

6. The Memorandum of Understanding (MOU) between PG&E and Disability Rights Advocates (DIRA) in Appendix B of today's Opinion is adopted. PG&E shall comply with the MOU.

7. PG&E shall file an advice letter (AL) in time to begin offering by June 1, 2007, the mobile home park Bill-Calculation Services described in the body of this Decision and Exhibit PG&E-70. The AL shall contain tariffs and services agreement that are substantially similar to those attached to Exhibit PG&E-70.

8. PG&E shall bear the cost of the new service quality standard adopted by the Settlement which provides for a \$100 payment to each customer whose service is erroneously shut off.

9. Within 30 days from the effective date of this Order, PG&E shall file a compliance advice letter to establish the one-way Humboldt Bay Power Plant (HBPP) memorandum account in accordance with paragraph 30 of the Settlement Agreement. The HBPP memorandum account shall accrue interest at the rate earned on prime, 3-month commercial paper as reported in Federal Reserve Statistical Release H-15.

10. PG&E shall incorporate into its Diablo Canyon license renewal feasibility study the findings and recommendations from the California Energy Commission's (CEC) assessment of Diablo Canyon conducted by the CEC pursuant to Assembly Bill 1632.

11. PG&E shall submit by June 30, 2011, an application on whether to renew the Diablo Canyon operating licenses. The application shall address the matters identified in the body of today's Opinion.

12. PG&E shall identify and track all expenditures for membership dues in organizations that engage in political activities, including all the organizations

identified by TURN in this proceeding, and record an appropriate proportion of these expenditures in the below-the-line Account 426.4.

13. In its next general rate case (GRC) proceeding, PG&E shall incorporate into its calculation of working cash a lag for the Company's matching contributions to the savings-fund pool. The lag for savings-fund contributions shall be determined in a manner consistent with the directions contained in the body of today's Opinion.

14. PG&E shall record, for ratemaking purposes, a regulatory liability for asset removal costs as set forth in the body of today's Opinion. The regulatory liability shall not apply to asset removal obligations (AROs) determined in accordance with generally accepted accounting principles (GAAP). Parties may address in PG&E's next GRC whether PG&E should record, for ratemaking purposes, a regulatory liability for AROs.

15. In its next GRC proceeding, PG&E shall provide to The Utility Reform Network (TURN), upon request, the information that TURN may need to compare (i) removal costs for AROs determined in accordance with GAAP, and (ii) removal costs for the same assets determined in accordance with Standard Practice U-4.

16. PG&E shall submit the following reports and information in its next GRC proceeding:

- i. An up-to-date analysis, along with supporting workpapers, of its DA costs so that appropriate DA fees may be set.
- ii. A separate flat fee for not-sufficient-funds for each of the major customer classes that reflects then-current costs and supporting work papers.

- iii. A report that demonstrates that (a) PG&E has reduced its rate base by the actual salvage value of the existing airplane, and (b) the depreciation expense for the replacement airplane is based on a 13-year service life.
- iv. The report that PG&E is required to submit pursuant to paragraph 32 of the Settlement Agreement at the end of the 2007 GRC cycle shall state if any funds collected in rates for contributions to trusts for post-retirement benefits other than pensions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.
- v. A report of the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and a forecast of future OR and OFA costs based on its actual payment history.
- vi. A report that contains (a) the then-current balance of pre-funded asset removal costs (ARCs); (b) a year-by-year projection of (1) when the then-existing balance of pre-funded ARCs will be consumed, and (2) the implicit inflation rate for future ARCs; and (c) a five-year projection of the year-end balance of pre-funded ARCs showing for each year the gross additions to the balance, gross expenditures for ARCs, and the net change in the balance of pre-funded ARCs.
- vii. A forecast of labor costs in 2011 for A&G Study departments and other office-based departments, broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

17. All advice letters filed pursuant to this Order shall comply with General Order 96-A and shall be subject to a finding of compliance by the Energy Division or its successor. The Commission's Energy Division may approve, without a Commission resolution, all the advice letters filed pursuant to this Order if such advice letters comply with today's Opinion.

18. The motion to adopt the Settlement Agreement is granted.

19. PG&E shall comply with its accord with the Greenlining Institute regarding supplier diversity, Board-of-Directors diversity, management diversity, and corporate philanthropy.

20. Application 05-12-002 is granted and denied to the extent set forth in the previous ordering paragraphs.

21. Application 05-12-002 and Investigation 06-03-003 remain open to address issues associated with PG&E's request to close its front counters.

This Order is effective today.

Dated March 15, 2007, at San Francisco, California.

MICHAEL R. PEEVEY

President

DIAN M. GRUENEICH

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TIMOTHY ALAN SIMON

Commissioners

I will file a concurrence.

/s/ TIMOTHY ALAN SIMON

Commissioner

Appendix A:

List of Appearances

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(END OF APPENDIX A)

Appendix B:

PG&E-DIRA Memorandum of Understanding (MOU)

Note: The Signed Copy of the MOU is in the Formal File for this proceeding. Appendix B of today's Opinion is an electronic copy of the MOU that does not show the parties' signatures.

Memorandum Of Understanding

This Memorandum of Understanding ("MOU") is made by and between Disability Rights Advocates ("DIRA") and Pacific Gas and Electric Company ("PG&E") (collectively, the "Parties"). In this MOU, the Parties agree on a mutually acceptable outcome to certain access issues raised by DIRA as an Intervenor in the Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007 (A.05-12-002).

RECITALS

WHEREAS the *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007* (A.05-12-002), contains forecasts of costs for test year 2007;

WHEREAS DIRA has raised certain issues regarding the impact of PG&E's practices on people with Mobility Disabilities and Vision Disabilities including: (1) access to Local Offices; (2) access to Pay Stations; (3) access to Pedestrian Rights of Way around PG&E Construction Sites; and (4) whether utility poles impede access in the Pedestrian Right of Way; and

WHEREAS PG&E and DIRA desire to resolve the issues raised by DIRA without further litigation in the current proceedings.

AGREEMENT

NOW THEREFORE, in consideration of the above Recitals and for good cause, as demonstrated below, it is hereby agreed as follows:

1 Definitions

The terms specified in this Section 1, when used in this MOU and the Recitals with the initial letters capitalized, whether in the singular or the plural, shall have the meanings stated in this Section 1.

- 1.1 AAA: The American Arbitration Association, or any successor organization.
- 1.2 Applicable Law: All federal and state laws and regulations that protect the rights of people with disabilities to full and equal access to governmental programs, services and activities and/or places of public accommodation, including Cal. Gov. Code §§ 4450, and 11135 *et seq.*, Cal. Civ. Code §§ 51 *et seq.*, and 54 *et seq.*, the Americans with Disabilities Act of 1990, 42 U.S.C. § 12101 *et seq.* and its implementing regulations including the Americans with Disabilities Act Access Guidelines (“ADAAG”), and Section 504 of the Rehabilitation Act of 1973, 29 U.S.C. Sec. 794, provided however, that nothing in this MOU shall require such programs, services and activities or places of public accommodation to provide such access if exempted from doing so, or otherwise not required to do so, under these federal and state laws and regulations.
- 1.3 Compliance Period: The Parties agree that the MOU shall become effective the day after CPUC approval and shall remain in effect until January 1, 2010.
- 1.4 Construction Sites: Areas in the Pedestrian Right of Way where PG&E is performing construction or repair of electric or gas service equipment. As used herein, “Construction Sites” do not include inspections of electric or gas facilities in the Pedestrian Right of Way.
- 1.5 CPUC: The Public Utilities Commission of the State of California.
- 1.6 Effective Date: The effective date of this MOU is the day after the CPUC approves this MOU.
- 1.7 Local Offices: Those portions of the 84 existing PG&E-operated offices open to the public for payment of PG&E bills.
- 1.8 Mobility Disability: With respect to an individual, any limitation of a person’s ability to move his or her body, or a portion of his or her body, that would cause the person to meet the definition set forth in 42 U.S.C. § 12102(2)(a) and/or Cal. Gov. Code § 12926(k).

- 1.9 Pay Stations: Businesses owned and operated by third parties that are authorized by PG&E to accept payment of PG&E bills. Pay Stations are also known as Neighborhood Payment Centers.
- 1.10 Parties: Disability Rights Advocates and PG&E.
- 1.11 Pedestrian Rights of Way: Sidewalks and other pathways used by pedestrians along public rights of way in PG&E's electric and gas service territory.
- 1.12 Proceeding: *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007* (A.05-12-002).
- 1.13 Transaction-Related Elements: This term is defined in Section 4.1 of this MOU.
- 1.14 Vision Disability: With respect to an individual, any limitation of a person's ability to see that would cause the person to meet the definition set forth in 42 U.S.C. § 12102(2)(a) and/or Cal. Gov. Code § 12926(k).

2 Terms

- 2.1 DIRA agrees that if this MOU is approved by the CPUC, DIRA will not pursue further, on its own behalf, any of the issues that it has raised in this Proceeding prior to 2008, other than disputes regarding PG&E's implementation of this MOU. DIRA further reserves the right to seek enforcement of the obligations set forth in this MOU. Nothing in this Section 2.1, however, should restrict DIRA's ability to participate in future settlement discussions or evidentiary proceedings that may take place in the Proceeding concerning Local Offices and Pay Stations. Further, nothing in this Section 2.1 is intended to restrict DIRA's ability to represent third parties or practice law concerning the issues raised in this Proceeding, as envisioned by Rule 1-500 of the Rules of Professional Conduct of the State Bar of California.
- 2.2 This MOU embodies the entire understanding and agreement of the Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Parties with respect to those matters.

- 2.3 This MOU represents agreement between the Parties to the facts and law as specified. The Parties agree that this MOU should not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
- 2.4 The Parties agree that this MOU is reasonable in light of the testimony submitted, consistent with law, and in the public interest.
- 2.5 The Parties agree this MOU shall not be construed against any Party because that Party or its counsel or advocate drafted the provision.
- 2.6 This MOU may be amended or changed only by a written agreement signed by the Parties.
- 2.7 The Parties shall jointly request CPUC approval of the MOU and shall actively support: (1) prompt approval of the MOU and (2) PG&E's request for additional funding as provided herein.
- 2.8 The Parties intend the MOU to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MOU, the Parties reserve their rights to renegotiate this MOU.
- 2.9 Captions are included for reference only, and are not intended to affect the meaning of the contents or the scope of this MOU.
- 2.10 This MOU shall be governed by and construed in accordance with California law. Each provision of this MOU shall be interpreted in such a manner as to be valid and enforceable under California law, but if any provision hereof shall be or become prohibited or invalid under any applicable law, that provision shall be ineffective only the extent of such prohibition or invalidity, without thereby invalidating the remainder of that provision or any other provision hereof.
- 2.11 This MOU may be executed in counterparts, which taken together shall constitute an original. Facsimiles of original pages shall be binding on the Parties to the MOU. The Parties shall exchange original signed counterparts as soon as possible.
- 2.12 The Parties agree that, except as otherwise noted below, the CPUC retains exclusive jurisdiction to enforce the terms of this MOU and resolve any disputes regarding the Parties' performance under this MOU.

3 Local Offices

- 3.1 To the extent that any of PG&E's Local Offices remain open to accept payments made in person by PG&E customers, such offices will be accessible to members of the public with Vision Disabilities and Mobility Disabilities in accordance with Applicable Law.
- 3.2 PG&E represents that a third party accessibility expert has surveyed, or will survey, each of its currently open Local Offices regarding their accessibility and compliance with Applicable Law. Consistent with the results of such surveys, PG&E will make all improvements necessary to ensure that all open Local Offices are accessible to people with Mobility Disabilities and Vision Disabilities in accordance with Applicable Law.
- 3.3 PG&E will engage a third-party accessibility expert to survey the accessibility of 10% of all open Local Offices in 2007, and 20% of all open Local Offices annually in 2008 and 2009. Prior to engagement of the expert, PG&E will notify DIRA of the identity of the expert and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected expert, PG&E will select a different expert, taking DIRA's concerns into account in the selection of the different expert. If such surveys identify barriers to accessibility in violation of Applicable Law, PG&E will have a reasonable time to make those improvements that are necessary to comply with Applicable Law. PG&E will provide the results of such surveys to DIRA, along with an estimate of the time that may be required to perform any necessary improvements.

4 Pay Stations

- 4.1 PG&E will engage a third-party accessibility expert to survey the transaction-related elements of accessibility at its Pay Stations ("Transaction-Related Elements") that are necessary to allow customers to complete PG&E-related transactions at such Pay Stations to ensure that these elements are in compliance with Applicable Law. These Transaction-Related Elements are set forth below:
 - Parking facilities for those Pay Stations that provide parking in a facility that is under the Pay Station's control;

- Pathway(s) from the parking area to the entrance of the Pay Station for those Pay Stations that control the pathway(s) from the parking area to the entrance, including ramps along the pathway(s) (if any);
 - Entrance(s) to the Pay Station, including ramps to the entrance(s) (if any);
 - Pathway(s) from the entrance(s) to the service counter(s) and other areas, if any, where PG&E-related transactions take place;
 - Service counter(s) and other areas or equipment, if any, where PG&E-related transactions take place; and
 - For those Pay Stations that are part of a franchise or that constitute a single location within a business entity that has five or more total locations, public restrooms provided by that Pay Station, if any, that are available to customers who conduct PG&E-related transactions at the Pay Station.
 - PG&E will survey 10 % or more of its Pay Stations annually in 2007, 2008 and 2009 to ensure compliance with these Transaction-Related Elements. PG&E will provide the results of such surveys to DIRA.
- 4.2 Prior to engagement of the expert described in Section 4.1 of this MOU, PG&E will notify DIRA of the identity of the expert and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected expert, PG&E will select a different expert, taking DIRA's concerns into account in the selection of the different expert.
- 4.3 If the above-referenced surveys identify barriers to accessibility concerning the Transaction-Related Elements that are not in compliance with Applicable Law, the relevant Pay Station operators shall be notified that they have a reasonable time to make the necessary improvements to remove such barriers and, if they fail to do so, the Pay Station will be removed from PG&E's network of authorized Pay Stations.
- 4.4 Only Pay Stations that comply with Applicable Law concerning the Transaction-Related Elements will be added to PG&E's network. At least three (3) of the Pay Stations that the third party accessibility expert

surveys each year will be Pay Stations that have been added to the network during the previous year.

- 4.5 Notwithstanding the above, should the need arise for the use of a new or existing Pay Station that does not provide accessible Transaction-Related Elements, PG&E will consult with DIRA prior to granting an exception to the above-stated policies, providing information to DIRA on the following factors: the location of the Pay Station, the number of payments it currently processes or is expected to process, the proximity of other Pay Stations that are accessible to persons with disabilities, and the Transaction-Related Elements that may not be accessible. PG&E will take these factors into consideration, as well as the feedback of DIRA, in determining whether or not to grant an exception.
- 4.6 PG&E agrees to create, maintain, and make reasonably available to the public (including by listing on its website) a list of Pay Stations that PG&E believes comply with Applicable Law concerning the Transaction-Related Elements. PG&E will make this list available to the public by June 30, 2007.

5 Resolution of Disputes regarding Local Offices and Pay Stations

- 5.1 Any controversy arising out of or relating to this MOU as it pertains to the accessibility of Local Offices or Pay Stations, shall be resolved at the request of any Party through a three-step dispute resolution process. First, the Parties will make a good-faith effort to meet and confer to attempt to resolve the dispute. Second, if the Parties cannot resolve the dispute through meet and confer, the Parties will attempt to resolve the dispute through mediation before a mutually-acceptable third-party mediator.
- 5.2 If mediation is unsuccessful, the Parties agree to submit the dispute to a final and binding arbitration before a randomly-selected arbitrator from the AAA panel in San Francisco, California, administered by and in accordance with the then existing Rules of Practice and Procedure of AAA. In the event of any such dispute, the parties shall be entitled to recover reasonable attorneys' fees and costs in accordance with applicable law regarding the recovery of attorneys' fees and costs.

- 5.3 This dispute resolution process does not apply to any dispute concerning any issue other than access by people with Mobility and Vision Disabilities to Local Offices and Pay Stations.

6 Temporary Construction Practices

- 6.1 PG&E agrees to prepare new protocols to ensure accessibility and safety around PG&E Construction Sites for persons with Vision Disabilities and Mobility Disabilities ("New Access Guidelines"). PG&E will include the New Access Guidelines in its Work Area Protection Guide, a copy of which is generally maintained in all PG&E crew trucks dispatched to job sites.
- 6.2 PG&E reserves the right to modify the New Access Guidelines to the extent such modifications are necessary to comply with law or, update its practices after determining the efficiency of the New Access Guidelines. If the New Access Guidelines are modified, PG&E will promptly provide a copy of the modified New Access Guidelines to DIRA.
- 6.3 PG&E agrees to conduct training of employees who will be required to comply with the New Access Guidelines. The training will inform the employees of the purpose of the New Access Guidelines and include a demonstration of the proper use of new barriers, warning signs and temporary wheelchair ramps that will be required by the New Access Guidelines. PG&E will also include the New Access Guidelines in its annual trench safety awareness training. PG&E will provide a copy of the relevant training materials to DIRA for review.
- 6.4 PG&E also agrees to make construction supervisors responsible for reviewing compliance with the New Access Guidelines when the supervisors visit Construction Sites. PG&E agrees to engage a disabled access consultant to assist PG&E in developing new construction protocols, training utility employees, and assisting PG&E supervisors in the field as needed regarding the use of the new equipment during the first year after this MOU is effective. Prior to engagement of the consultant, PG&E will notify DIRA of the identity of the consultant and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected consultant, PG&E will select a different consultant, taking DIRA's concerns into account in the selection of the different consultant. The consultant shall review PG&E's adherence to the New

Access Guidelines, including as appropriate its use of the new equipment contemplated by the New Access Guidelines at no fewer than ten (10) Construction Sites in each of PG&E's seven (7) geographic areas. PG&E will provide to DIRA a summary of the consultant's conclusions and recommendations regarding the use of the new equipment biannually.

- 6.5 The New Access Guidelines have not yet been completed. The Parties have been working, and will continue to work, together to finalize New Access Guidelines that are acceptable to both parties. The Parties anticipate that they will be able to reach agreement on New Access Guidelines by September 30, 2006.
- 6.6 PG&E agrees to consult with DIRA regarding its compliance with the requirements of this Section 6. PG&E reserves the right to make any modifications to its practices that PG&E deems necessary or appropriate consistent with the intent of this MOU. If the Parties are unable to reach agreement on any of these issues, the Parties will first attempt to resolve any disputes through mediation before a mutually agreeable mediator. If the Parties are unable to resolve a dispute regarding any issues addressed in Section 6 of this MOU after mediation, such dispute shall be subject to CPUC jurisdiction as provided in Section 2.13.
- 6.7 PG&E estimates that implementation of procedures to comply with the New Access Guidelines would cost approximately \$3.3 million in test year 2007. PG&E and DIRA request that the final decision in this proceeding increase PG&E's revenue requirement for test year 2007 to comply with the New Access Guidelines in the amount of \$3.3 million total (\$1.4 capital/\$1.9 million expense).

7 Utility Poles in Pedestrian Rights of Way

- 7.1 PG&E will obtain a sampling of its pole locations during 2007 to determine whether and to what extent they pose accessibility barriers for persons with Vision Disabilities or Mobility Disabilities.
- 7.2 During 2007, PG&E's pole test and treat contractors will measure the clearance between PG&E-owned or jointly-owned utility poles located in the Pedestrian Right of Way and the edge of a sidewalk where it appears based on a visual inspection that the distance between the pole and the edge of the sidewalk furthest from the pole may be less than 36 inches.

PG&E will keep a record of the information it collects through this survey and will provide such information to DIRA. PG&E's contractors shall not be required to measure the clearance of more than two locations on a single block where it appears that the distance between the poles and the edge of the sidewalk are uniform.

- 7.3 PG&E and DIRA will meet and confer in good faith regarding the data collected during 2007 to discuss whether further Commission proceedings or other actions are necessary or appropriate to address any access barriers noted in the survey.
- 7.4 PG&E estimates that its incremental cost estimate to conduct a survey in 2007 of approximately 42,000 utility poles in the San Francisco, San Jose and Sacramento areas is approximately \$142,000. PG&E and DIRA request that the final decision in this proceeding include an additional amount of \$142,000 in revenue requirements (expense) for test year 2007.

8 Intervener Status and Compensation

- 8.1 PG&E agrees that the issues resolved herein were properly raised by DIRA and that DIRA has made a substantial contribution to this proceeding, as defined by Rule 1803(a) of the Commission's Rules of Practice and Procedure. The Parties agree that it is reasonable and appropriate for DIRA to receive intervenor compensation for certain tasks performed to implement the MOU, to the extent directed by the Commission.

IN WITNESS WHEREOF this MOU is executed and agreed to by the following as of the date set forth below.

//

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Dated: June 26, 2006

(END OF APPENDIX B)

Appendix C:

General Rate Case Settlement Agreement

Note: The Signed Copy of the GRC Settlement Agreement is in the Formal File for this proceeding. Appendix C of today's Opinion is an electronic copy of the MOU that does not show the parties' signatures.

SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE MODESTO IRRIGATION DISTRICT, THE MERCED IRRIGATION DISTRICT, THE SOUTH SAN JOAQUIN IRRIGATION DISTRICT, THE WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION, THE DISABILITY RIGHTS ADVOCATES, THE CALIFORNIA FARM BUREAU FEDERATION, SOUTHERN CALIFORNIA EDISON, SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS AND ELECTRIC COMPANY, THE COALITION OF CALIFORNIA UTILITY EMPLOYEES

SETTLEMENT AGREEMENT

1. As a compromise among their respective litigation positions, and subject to the Settlement Conditions set forth in Section 3 of this Agreement, the parties to this Settlement (Settling Parties) agree on a mutually acceptable outcome to all issues in Application (A.) 05-12-002, Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007 (2007 General Rate Case, or GRC), with the exception of issues raised by the Greenlining Institute. The Settlement is presented to the Commission pursuant to Rule 51 of the Commission's Rules of Practice and Procedure.

SETTLING PARTIES

2. The Settling Parties are as follows: the Division of Ratepayer Advocates (DRA), Pacific Gas and Electric Company (PG&E), the Modesto Irrigation District (Modesto ID), the Merced Irrigation District (Merced ID), the South San Joaquin Irrigation District (SSJID), the Western Manufactured Housing Communities Association (WMA), the Disability Rights Advocates (DIRA), the California Farm Bureau Federation (CFBF), Southern California Edison (SCE), Southern California Gas Company (SoCalGas), San

Diego Gas and Electric Company (SDG&E), and the Coalition of California Utility Employees (CCUE).

SETTLEMENT CONDITIONS

3. The Settling Parties agree to the following general conditions:
 - A. This Settlement resolves all issues raised by all Parties, with the exception of issues raised by the Greenlining Institute.
 - B. This Settlement and the tables presented in the Appendices embody the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
 - C. Following Rule 51.8, the Settling Parties agree that this Settlement should not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.
 - D. The Settling Parties agree that this Settlement is reasonable in light of the entire record, consistent with law, and in the public interest.
 - E. The Settling Parties agree that no provision of this Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
 - F. This Settlement may be amended or changed only by a written agreement signed by the Settling Parties.
 - G. The Settling Parties shall jointly request Commission approval of this Settlement and shall actively support prompt approval of the Settlement.
 - H. The Settling Parties intend the Settlement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement, the Settling Parties reserve their rights under Rule 51.7.
 - I. This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.
 - J. This Settlement shall become effective among the Settling Parties on the date the last Party executes the Settlement as indicated below.

- K. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Settlement on behalf of the Settling Parties they represent.
- L. The fact that the Settling Parties set forth specific amounts for certain categories of costs is not intended to limit PG&E's management discretion to spend funds as it sees fit and consistent with its obligation to serve.
- M. Merced ID joins only in the following sections of this Settlement: paragraphs 1, 2, 3, 10, 11, 19 and 50.
- N. Modesto ID joins only in the following sections of this Settlement: paragraphs 1, 2, 3, 10, 11, 19, 49 and 50.
- O. SSJID joins only in the following sections of this Settlement: paras. 1, 2, 3, 10 and 19.
- P. WMA joins only in the following sections of this Settlement: paras. 1, 2, 3, 12 and 25.
- Q. DIRA joins only in the following sections of this Settlement: paras. 1, 2, 3, 13A, and 48.
- R. CFBF joins only in the following sections of this Settlement: Paragraphs 1, 2, 3, 13B, and 24.
- S. SCE, SDG&E and SoCalGas join only in the following sections of this Settlement: paragraphs 1, 2, 3, 13C, and 41, but solely for the purpose of supporting the use of the traditional method for computing and reflecting net salvage rates (as described in Commission Standard Practice U-4). SCE, SDG&E and So Cal Gas did not address, and express no opinion on, the actual net salvage percentage rates adopted in the Settlement.

SETTLING PARTIES LITIGATION POSITIONS

Pacific Gas and Electric Company

- 4. At the end of hearings, and as reflected in Exhibit PG&E-79 (Comparison Exhibit), PG&E requested the Commission to approve total CPUC jurisdictional billed

revenue requirements of \$5.109 billion,²⁷⁸ effective January 1, 2007. This total consisted of \$2.991 billion for electric distribution, \$1.062 billion for gas distribution, and \$1.056 billion for electric generation. Compared to adopted revenue requirements for 2006, PG&E's request represented a total revenue increase of \$394.5 million, consisting of \$342.8 million for electric distribution, \$35.5 million for gas distribution, and \$16.3 million for electric generation.

5. PG&E's proposed revenue requirement for 2007 was based on the costs PG&E forecasted it would incur in 2007 to own, operate, and maintain its electric generating, electric distribution, gas distribution, and common and general plant, to perform the transactions necessary to procure electricity for its bundled-service electric customers and to procure gas for its core gas customers, and to provide customer services to its electric and gas customers.

6. In addition to the revenue requirement increases for 2007, PG&E requested attrition revenue requirement increases of \$143 million in 2008 and of \$180 million in 2009. These amounts reflect net savings from Business Transformation.

7. PG&E also sought to increase: (1) its uncollectibles factor from 0.002 to 0.002772; (2) its "restoration for non-payment" fee (gradually over the course of the rate case cycle) from \$20 to \$40 for reconnection during regular business hours and from \$30 to \$60 for reconnection during non-business hours (CARE customers would receive a 20% discount on the increased restoration for non-payment fee); and (3) its "non-sufficient funds" fee from \$8.00 to \$11.50.

²⁷⁸ This amount and all other amounts are in nominal FERC dollars unless noted otherwise.

Division of Ratepayer Advocates

8. At the end of hearing, and as reflected in the Comparison Exhibit, DRA's proposed overall forecast test year 2007 electric and gas distribution and electric generation CPUC jurisdictional billed revenue requirements would be \$2.809 billion, \$1.001 billion, and \$0.924 billion, respectively. Based on current authorized revenues, DRA's proposed revenue requirements would result in an increase of \$160.9 million for electric distribution and decreases of \$25.3 million and \$115.5 million for gas distribution and electric generation, respectively.

9. DRA's recommended attrition increases, after adjustment for Business Transformation savings, would total \$100 million in 2008 and \$131 million in 2009. DRA also recommended an uncollectibles factor of 0.002582. DRA proposed that any increase in the "restoration for non-payment" fee be limited to 25% more than the current fees, and that CARE customers should receive a 20% discount off the increased fees. DRA took no position on PG&E's proposed increase of the "non-sufficient funds" fee.

Modesto Irrigation District, Merced Irrigation District and South San Joaquin Irrigation District

10. Modesto ID, Merced ID and SSJID (the "Irrigation Districts") asserted that customers should not fund PG&E's \$2.0 million request for Customer Retention activities or the \$0.3 million request for related Regulatory/Legislative activities. SSJID also recommended disallowance of \$1.6 million for Economic Development activities and \$0.4 million for Military Facilities Acquisition activities.

11. In addition, Merced ID and Modesto ID called for an investigation of PG&E's implementation of Schedule E-31 to determine whether abuses are occurring. Modesto ID also called for an investigation of whether PG&E has complied with the terms of the Removal of Idle Facilities Agreement.

WMA

12. The Western Manufactured Housing Communities Association (WMA) filed a counter-proposal to PG&E's proposed bill calculation services for mobile home park owners. (PG&E's original proposal would have provided a limited amount of services to mobile home park owners at no cost to participating mobile home park owners.) Under WMA's counter-proposal, which was modeled closely after the billing services developed by Southern California Edison Company, PG&E would provide a higher level of service than originally proposed, performing the actual calculations for the mobile home park owners and charging a fee for such services to participating mobile home park owners. The joint proposal developed by WMA, PG&E and The Utility Reform Network (TURN) -- submitted as Exhibit PG&E-70 -- adopts WMA's counter-proposal with certain minor modifications.

DIRA, CCFB, SCE, SDG&E, So Cal Gas, CCUE

13. The other settling parties that also participated in the case include:

- A. Disability Rights Advocates (DIRA) submitted prepared testimony in the following areas: (i) access to local offices, (ii) access to third-party pay stations, (iii) access around PG&E construction projects in the pedestrian right of way; (iv) whether utility poles create barriers in the pedestrian right of way; and (v) whether PG&E's paving practices comply with applicable law. The Memorandum of Understanding (MOU) executed by DIRA and PG&E - submitted as Exhibit PG&E-71 - addresses the first four of these areas, without prejudging or compromising any further settlement negotiations with other parties concerning the local office and pay station issues. Regarding the fifth area, as part of the MOU, DIRA agrees to withdraw from the 2007 GRC its proposals regarding paving practices, as well as any other issues raised in the GRC but not addressed by the MOU. However, nothing in the MOU limits DIRA's right to seek to raise these issues in future GRC proceedings.
- B. The California Farm Bureau Federation (CFBF) presented direct testimony opposing the closure of the front counters at PG&E's local offices.
- C. Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and Southern California Gas (SoCalGas) Companies presented testimony on the

subject of depreciation in rebuttal to the testimony of The Utility Reform Network.

- D. The Coalition of California Utility Employees (CCUE) intervened in this case on behalf of its unions whose 35,000 members work at nearly all of the electric utilities in California, including approximately 13,000 working at PG&E.

SETTLEMENT TERMS

Revenue Requirement

14. The 2007 CPUC jurisdictional billed revenue requirement of \$2.870 billion for electric distribution, \$1.047 billion for gas distribution and \$1.010 billion for generation operations for a total of \$4.927 billion is reasonable. This represents increases of 8.4% and 2.0% in PG&E's electric and gas distribution revenues, and a decrease of 2.9% in generation operation revenues, for an overall increase of 4.5%, and compares to PG&E's requests (Comparison Exhibit, p.1-4) of increases in revenues of 12.9%, 3.5%, and 1.6% for electric and gas distribution and generation operations, respectively, for an overall increase of 8.4%. Appendices A and B summarize the proposed settlement revenue requirements. On a total system billed revenue basis, the revenue increase amounts to 1.4 % for 2007.

15. Forecasts of Customers and Sales: The forecasts of gas and electric customers and sales set forth in PG&E's showing (Ex.PG&E-8) will be adopted.

16. Revenues at Present Rates: The forecasts of adopted gas and electric revenues at present rates as set forth in PG&E's showing (Ex.PG&E-79, p.2-3. p.2-14, p.2-25) will be adopted. The forecasts of billed revenues at present rates as set forth in PG&E's showing (Ex.PG&E-2, Ch.14 (electric) and Ch.15 (gas)) will be adopted.

Operations & Maintenance (O&M) Expense

17. PG&E's 2007 expenses will be handled in the following manner: 2007 O&M expenses will be \$488.8 million for electric distribution, \$139.9 million for gas

distribution, and \$450.6 million for electric generation operations, for a total of \$1.079 billion. This compares to PG&E's litigation position set forth in the Comparison Exhibit of \$494.2 million (p. 2-4, Line 7 and 8), \$142.5 million (p. 2-15, Lines 7 and 8), and \$457.0 million (p. 2-26, Lines 5 and 7) for electric and gas distribution and generation operations, respectively, for a total of \$1.094 billion.

18. **Vegetation Management:** Vegetation Management expense (included in the above electric total) will be \$150 million in 2007 (SAP dollars).

- A. The Vegetation Management Balancing Account will remain a one-way balancing account.
- B. It is difficult to forecast the costs of the California Department of Forestry and Fire Protection (CDF) required work in this rate case, however, as PG&E and CDF are in discussions regarding hazard trees and PG&E's request for a major woody stem exemption from CDF. Thus, it is unclear whether these issues will dramatically increase costs for vegetation management or will not have any impact on those costs.
- C. A separate tracking account will be established in which PG&E shall record any increased inspection or removal costs PG&E incurs due to (a) new CDF rules and/or requirements that increase hazard tree inspections or removals; (b) re-interpretation by CDF of its existing rules and/or requirements that increase hazard tree inspection or removals; (c) changes in CDF enforcement approach that require PG&E to significantly increase the scope of its Vegetation Management program, either through significantly increased inspections or tree mitigation activities, or (d) new incremental work related to so-called major woody stems, including removal of the major woody stems, adding tree wire to existing lines if appropriate, or relocating power lines further away from major woody stems.
- D. PG&E shall send a letter, and a copy of the new CDF requirements, enforcement action, and/or rules, to the Commission's Energy Division and to DRA within 30 days to inform parties of this occurrence.
- E. If the costs in the separate tracking account exceed \$5 million in any calendar year, and if PG&E's overall expenses for Vegetation Management exceed \$150 million (as adjusted for attrition), PG&E shall be authorized to recover through an advice letter filing all costs appropriately recorded in this tracking account for that calendar year through the Distribution

Revenue Adjustment Mechanism (DRAM), or subsequent mechanism established by the Commission, subject to DRA audit of those costs showing compliance with the provisions above.

Customer Services Expenses

19. PG&E's distribution Customer Services 2007 expenses will be \$431.1 million for electric and gas distribution. This compares to PG&E's litigation position set forth in the Comparison Exhibit (p. 2-4 and 2-15, lines 9 and 11) of \$437.7 million. This reflects a "zero" allocation in expenses for the "customer retention" component of PG&E's Customer Retention and Economic Development Program. (This compares to the \$2.03 million originally sought by PG&E and reflected in Ex. PG&E-5, p. 9-1, Table 9-1, L:1.)

20. **Uncollectibles:** The factor used to calculate uncollectibles expense will be set at 0.002586.

21. **Non-sufficient Funds Fee:** The non-sufficient funds (NSF) fee for returned checks will be increased from the current \$8.00 to \$11.50. Within 30 days from the date of a Commission decision in this matter, PG&E will make a compliance advice filing to implement this provision.

22. **Restoration for Non-payment Fee:** The fees to restore service to customers whose service has been terminated due to lack of payment will be increased from the current \$20.00 for restoration during business hours and \$30.00 for restoration during non-business hours to \$25.00 for restoration during business hours and \$37.50 for restoration during non-business hours. However, CARE customers shall be exempt from the increase and shall continue to be liable for the current fees (\$20.00 and \$30.00). Within 30 days from the date of a Commission decision in this matter, PG&E will make a compliance advice filing to implement this provision.

23. **New Quality Assurance Standard for Improper Shut-offs:** The Commission should adopt a new quality assurance standard under which a customer would be paid

\$100.00 by PG&E if PG&E improperly disconnects gas and/or electric service to the customer. The Settling Parties also agree that the Commission should order PG&E to explain the new standard via an advice filing to be made by PG&E within 90 days of the date of the Commission's decision in this matter. Furthermore, the Settling Parties agree that, prior to PG&E's advice filing, PG&E should meet with any interested parties in order to resolve as many details concerning implementation of the new standard as practicable.

24. Closure of Front Counters at Local Offices: PG&E will keep its 84 front counters at local offices open pending resolution of this issue either through settlement or Commission decision. If any front counters are ultimately closed, PG&E will adjust its revenue requirement downward to reflect savings associated with such closures. The amount of such adjustment depends upon the number of front counters closed, and therefore cannot be determined at this time.

25. Billing Services for Mobile Home Parks: The billing services to be provided by PG&E for mobile home park owners, as jointly proposed by Western Manufactured Housing Communities Association (WMA), The Utility Reform Network (TURN) and PG&E in Exhibit PG&E-70 are reasonable and should be adopted by the Commission.

26. Direct Access Service Fees: Direct access service fees will remain at current levels.

Capital Additions

27. The net weighted capital additions for 2007 will be \$272.5 million for the electric distribution UCCs and \$98.1 million for the gas distribution UCCs and \$81.9 million for generation operation UCCs, for a total of \$452.5 million. The net additions for 2005, 2006, and 2007 are shown in the Appendix G, Settlement Comparison Exhibit, Plant in Service tables for electric and gas distribution and electric generation (p.1-7, 2-7, 3-7).

28. **Replacement Airplane:** The \$81.9 million of capital additions for generation operation UCCs includes PG&E's \$18.0 million capital request for a replacement airplane. PG&E employees (including employees, officers, and Board members of PG&E Corporation) will be prohibited from using the Company airplane for personal travel for themselves or their family. PG&E customers and contractors, including customers and contractors of PG&E Corporation, will also be prohibited from using the Company plane for personal travel for themselves or their family.

29. Currently, PG&E implements a charge back system for passenger use of the airplane, including PG&E Corporation employees. For PG&E Utility and Corporation employees, and contractors working directly for PG&E, a \$400 round trip charge is currently made to the PCC or order number of the department for whom each PG&E employee or contractor works. PG&E agrees to review and update its chargeback procedures and rates, and present the results of this update to the Commission and DRA within 90 days of a final decision in this case.

30. **Humboldt Bay Power Plant Memorandum Account:** The Settlement includes revenue requirements for some specific projects which may be required for the continued operation of the existing units at Humboldt Bay Power Plant. The estimated revenue requirements for these projects are: \$1.3 million in 2007, \$876 thousand in 2008 and \$709 thousand in 2009. These projects are listed in Appendix C. The Settling Parties further agree that PG&E will establish a memorandum account to track the difference between the authorized and actual revenue requirement associated with these projects, and, in the next GRC, will refund any over collection of revenue requirements if it is not necessary to perform these projects.

Administrative and General (A&G) Expense

31. PG&E's total utility 2007 A&G expenses will be \$772.3 million (\$2004). This compares to the \$806.3 million (\$2004) in PG&E's position in the Comparison Exhibit,

p. F-5. These amounts equate to CPUC jurisdictional A&G amounts in 2007 FERC dollars (Appendix B) of \$708.7 million compared to \$741.5 million, respectively.

32. A&G Expense – Post-retirement Benefits Other than Pension (PBOP) – Medical and Life, and Long-Term Disability Trusts: The estimate of total contributions for 2007 to the PBOPs medical and life, and LTD trusts will be \$124.3 million (total company before allocation to capital and other non-GRC UCCs). This total amount will also apply to the attrition years. In compliance with Decisions 92-12-015 and 95-12-055, PG&E will file a consolidated true-up of the revenue requirements associated with the PBOPs medical, life and LTD contributions at the end of the 2007 GRC cycle.

33. Capitalization Rates for A&G: The capitalization rates for those A&G items that are capitalized in the following accounts are as follows:

Account 920: Performance Incentive Plan	24.10%
Account 920: Salaries	11.12%
Account 921: Office Supplies	11.59%
Account 923: Outside Services	1.40%
Account 925: Workers Compensation	32.61%
Account 925: Third Party Claims	19.10%
Account 926: Pension and Benefits	32.61%

34. A&G Allocation to Non-GRC UCCs: It is more efficient to litigate common costs like A&G only once, in the GRC, and then to use the results in other CPUC proceedings, rather than re-litigating these common A&G costs multiple times. A&G expenses allocated to the Unbundled Cost Categories (UCCs) adopted in this 2007 GRC should be used in determining the A&G expenses in related proceedings in 2007 and future years until PG&E's next test year GRC, if the outcome of those proceedings would otherwise require specific calculation of A&G expenses. Specifically, the UCCs and related proceedings are: Gas Transmission (Gas Accord III and subsequent PG&E

Gas Transmission and Storage proceedings) and Nuclear Decommissioning (including SAFSTOR) (the 2006 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) and subsequent NDCTP filing).

35. **Time Tracking for PG&E's Public Affairs Related Functions:** PG&E shall, within 90 days of a final decision in this case, adopt a time reporting system to track time and expenditures of those public policy and governmental affairs organizations that have a mixture of below the line activities in addition to activities for which PG&E seeks cost recovery from the CPUC. The organizations will include Governmental Relations, Area Public Affairs, Corporate Environmental and Federal Affairs, Federal Governmental Relations, and Civic Partnership and Community Initiative. If other organizations with below the line activities, in addition to activities for which PG&E seeks cost recovery from the CPUC, are formed in the future, those organizations will also use the adopted time tracking system. PG&E shall have this reporting system implemented and in place by no later than January 1, 2008.

36. **Administrative and General Expense Analysis and Forecasting:** PG&E will work with DRA and other interested parties to improve the A&G presentation for the next GRC, which will also include presenting recorded, base year, and forecast data in a consistent, comparable, and transparent manner.

37. **Pension:** On June 15, 2006, the Commission issued D.06-06-014 in this proceeding and A.05-12-021 adopting an uncontested settlement agreement authorizing PG&E to recover contributions to its employee pension plan, or retirement plan, during 2006-2009. (See Ex. 1-5 and Tr. 1-25.) This final decision resolves the pension contribution issue in both proceedings, closing A.05-12-021 (which addressed the pension contribution in 2006) and leaving this proceeding (which covers pension contributions in 2007-2009) open to address all remaining GRC issues. (D.06-06-014, mimeo, pp. 2 and 26.) As a result, PG&E is making retirement plan net contributions of \$249.7 million in 2006 and \$153.4 million each year in 2007, 2008 and 2009. (D.06-06-014,

mimeo, p. 10.) Based on actuarial estimates and an assumed annual trust investment return of 7.5%, these contributions are projected to result in a fully funded pension plan by the beginning of the next GRC cycle on January 1, 2010. (D.06-06-014, mimeo, p. 9.) No issues remain to be resolved in this GRC regarding PG&E's retirement plan for the years 2007-2009.

38. However, because this Settlement extends through the year 2010 (see paragraph 45), the question of a pension contribution for 2010 is now raised.

39. The pension contribution settlement approved in D.06-06-014 for the years 2007-2009 should be extended through the year 2010 for the purposes of this Settlement. Specifically, the Settling Parties agree to the following:

- A. PG&E is required to make a total pension contribution of \$176.0 million for the year 2010, which equates to a net contribution of \$153.4 million for the year 2010. (See D.06-06-014, *mimeo*, Finding of Fact 10 on p. 21.)
- B. PG&E will continue to recover the revenue requirement for the portion of the pension contribution authorized for 2010 that is allocable to PG&E's GRC lines of business. Recovery of the pension-contribution revenue requirement for non-GRC lines of business shall be authorized, as appropriate, in other proceedings and venues. (See D.06-06-014, *mimeo*, Ordering Paragraph 6 on p. 25.)
- C. The advice letter required by Ordering Paragraph 7 of D.06-06-014 shall extend through the year 2010.
- D. The annual report required by Ordering Paragraph 8 of D.06-06-014 shall continue through the year 2011.

Franchise Fee Factors

40. The factors used to calculate franchise fees will be 0.007603 (electric) and 0.009736 (gas).

Depreciation Expense

41. The 2007 depreciation expenses for electric and gas distribution, and electric generation will be \$596.8 million, \$209.4 million, and \$135.4 million, respectively, for a

total of \$941.6 million. The depreciation parameters resulting from DRA's position on electric, gas, and common plant depreciation (see Ex. DRA-16, p.16-2 to 16-3; Ex. DRA-16, p.16-11 to 16-12, Table 16-2) will be used, with the exceptions as shown in Appendix D.

42. **Fossil Decommissioning Refund:** PG&E will refund in adopted rates \$26.812 million per year in fossil decommissioning funds from 2007 through 2010. In the next GRC, PG&E will present an estimate of its future fossil decommissioning needs and true up the fossil decommissioning reserve at that time.

Rate Base

43. Recorded 2004 plant will be used as a starting point for calculating test year 2007 rate base. Residual common plant and depreciation reserve will be allocated using the allocation method presented in Ex. PG&E-2, pp. 8-8 to 8-10. The rate base for 2007 is \$12.6 billion. The weighted average Nuclear Fuel Inventory of \$221.9 million will be removed from electric generation rate base. The appropriate recorded carrying costs will be collected through the Energy Resources Recovery Account (ERRA) at the short term interest rate.

Other Operating Revenues

44. CPUC-jurisdictional Other Operating Revenues will be \$80.1 million for electric distribution, \$26.0 million for gas distribution and \$10.1 million for electric generation. (This compares to the \$79.1 million electric distribution, \$26.0 million for gas distribution and \$9.7 million for electric generation in PG&E's position in the Comparison Exhibit, pp. 2-3, 2-14 and 2-25.) The increase for electric distribution reflects the agreement on the non-sufficient funds fee and reconnection fee rates described above.

2011 Test Year GRC

45. PG&E's next GRC will be deferred until test year 2011 and a provision will be made for an attrition adjustment for 2010.

Attrition

46. **Attrition Authorized for Implementation by Advice Letter:** The attrition relief for 2008, 2009, and 2010 will be authorized in this GRC, and will be implemented by advice letter.

47. **Attrition Mechanism:** The attrition adjustment for base revenues for 2008 will be \$125 million. The attrition adjustment for 2009 will be \$125 million, plus a one-time additional amount of \$35 million for a second refueling outage at Diablo Canyon Power Plant anticipated in 2009, for a total of \$160 million. If a second refueling is not performed in 2009, then the \$35 million will be refunded in 2010. The attrition adjustment for 2010 will be \$125 million, less the one-time additional amount of \$35 million from 2009, for a total of \$90 million. If the anticipated 2009 second refueling outage is delayed until 2010, an additional \$35 million will be provided in 2010, which will be refunded in the event the refueling does not take place.

Other Settlement Items

48. **MOU between DIRA and PG&E:** The Memorandum of Understanding (MOU) between Disability Rights Advocates (DIRA) and PG&E, submitted jointly by DIRA and PG&E as Exhibit PG&E-71, is reasonable and should be approved by the Commission, provided, however, that if the upcoming rate case cycle is extended through 2010 (as provided for in paragraph 45) then DIRA and PG&E shall negotiate conforming changes to the MOU which had been designed to last only through 2009. The costs set forth in paragraphs 6.7 and 7.4 of the MOU are included in the amounts set forth in this Settlement.

49. **Removal of Idle Facilities Investigation:** Modesto ID and PG&E agree to negotiate, in good faith, possible revisions to the existing Removal of Idle Facilities Agreement, which may include a possible extension to that agreement. Accordingly, Modesto ID withdraws its request that the Commission commence an investigation into PG&E's compliance with the terms and conditions of that agreement. To the extent Modesto ID and PG&E are unable to reach agreement on revisions to the agreement, Modesto ID reserves its right to seek an investigation, or file a complaint, regarding PG&E's compliance with the terms and conditions of such agreement in a different proceeding at such time.

50. **Schedule E-31 Investigation:** In acknowledgement of the requirement in Public Utilities Code Section 454.1 that the Commission review and report on PG&E's Schedule E-31, Merced ID and Modesto ID withdraw their request in this proceeding that the Commission commence an investigation of PG&E's implementation of Schedule E-31. Merced ID and Modesto ID reserve their right to seek such an investigation, or file a complaint, in a different proceeding at a later date.

51. **AMI:** The costs and benefits associated with Advanced Metering Initiative (AMI) are to be addressed through balancing accounts that will continue until at least 2010. (D.06-07-027, pp. 46-47.) Because AMI will not be fully deployed until 2011, the Commission has directed PG&E to evaluate continuing these balancing accounts through the 2010-2012 GRC cycle and to submit testimony to that effect in PG&E's 2010 GRC. (D.06-07-027, p. 46.) The testimony will be submitted in PG&E's 2011 GRC. The only area where PG&E presented costs in both this GRC and the AMI proceeding was Information Technology (IT). PG&E removed the duplicative IT costs from its GRC request, as shown in Appendix G of the Comparison Exhibit. (Ex. PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.)

52. **Cost of Capital Proceedings:** Outcomes in future Cost of Capital proceedings could affect PG&E's revenue requirement. The resulting revenue requirements from these proceedings will be calculated using the adopted 2007 rate base amounts.

53. **O&M Labor Factors:** O&M labor factors will be calculated from 2004 recorded adjusted O&M labor. The factors are shown in Appendix F.

54. **Other Balancing Accounts:** PG&E may transfer the balances in the Electric and Gas Credit Facilities Fees Tracking Accounts (the ECFFTA and GCFFTA) to the electric Distribution Revenue Adjustment Mechanism (DRAM), the Utility Generation Balancing Account (UGBA), the gas Core Fixed Cost Account (CFCA) and the Noncore Customer Class Charge Account (NCA) for recovery from customers.

55. **Results of Operations Model:** PG&E will work with DRA to continue to streamline and improve the results of operations model for the next GRC.

56. **Earnings Sharing Mechanism:** PG&E will withdraw, and the Commission will not adopt, the earnings sharing mechanism set forth in Exhibit PG&E-10, Chapter 6. DRA will withdraw, and the Commission will not adopt, DRA's alternative to PG&E's earnings sharing mechanism set forth in Exhibit DRA-18.

57. **Performance Incentive Mechanism:** PG&E will withdraw, and the Commission will not adopt, the Performance Incentives set forth in Exhibit PG&E-11. No further proceedings on this topic will take place in this docket.

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ Patrick G. Golden

Name: PATRICK G. GOLDEN

Date: August 18, 2006

THE MODESTO IRRIGATION DISTRICT

By: /s/ Joy Warren

Name: JOY WARREN

Date: August 16, 2006

THE SOUTH SAN JOAQUIN IRRIGATION DISTRICT

By: /s/ Jeffrey K. Shields

Name: JEFFREY K. SHIELDS

Date: August 17, 2006

THE DISABILITY RIGHTS ADVOCATES

By: /s/ Roger Heller

Name: ROGER HELLER

Date: August 16, 2006

THE COALITION OF CALIFORNIA UTILITY EMPLOYEES

By: Tanya A. Gulesserian

Name: TANYA A. GULESSERIAN

Date: August 16, 2006

SOUTHERN CALIFORNIA GAS COMPANY

By: /s/ Steven D. Davis

Name: STEVEN D. DAVIS

Date: August 16, 2006

DIVISION OF RATEPAYER ADVOCATES

By: /s/ R. Mark Pocta

Name: R. MARK POCTA

Date: August 16, 2006

THE MERCED IRRIGATION DISTRICT

By: /s/ Tracy Hunckler

Name: TRACY HUNCKLER

Date: August 17, 2006

THE WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

By: /s/ Edward G. Poole

Name: EDWARD G. POOLE

Date: August 16, 2006

THE CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ronald Liebert

Name: RONALD LIEBERT

Date: August 16, 2006

SAN DIEGO GAS AND ELECTRIC COMPANY

By: /s/ Steven D. Davis

Name: STEVEN D. DAVIS

Date: August 16, 2006

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ John P. Hughes

Name: JOHN P. HUGHES

Date: August 16, 2006

SETTLEMENT AGREEMENT APPENDICES

<u>APPENDIX TITLE</u>	<u>PAGE</u>
A Results of Operations Summary	23
B Summary of Increase by Electric, Gas Distribution, and Generation	24
C Humboldt Bay Power Plant Projects Subject to Memorandum Account Tracking	25
D Settlement Net Salvage Rate Changes	26
E Settlement Attrition Summary	27
F O&M Labor Factors	28
G Settlement Comparison Exhibit	29

APPENDIX A: Results of Operations Summary (see Appendix G for Detail)

Pacific Gas and Electric Company
2007 General Rate Case - Position Summary
Results of Operations - Test Year 2007
(Thousands of Dollars)

		Comparison Exhibit (PG&E-79)				Difference from 2006 Authorized				
Line No.	Description	2006 Authorized	PG&E	DRA	Settlement	PG&E	DRA	Settlement	Reduction	Line No.
		(A)	(B)	(C)	(D)	(E) = (B) - (A)	(F) = (C) - (A)	(G) = (D) - (A)	(H) = (G) - (E)	
REVENUE										
1	Revenue at Effective Rates	N/A	5,148,380	4,772,226	4,967,422	N/A	N/A	N/A	N/A	1
2	Less Non-General Revenue	N/A	91,378	91,287	91,378	N/A	N/A	N/A	N/A	2
3	General Rate Case Revenue	4,817,540	5,239,758	4,863,513	5,058,800	422,218	45,973	241,260	(180,958)	3
4	Less FERC Allocation	(11,486)	(16,159)	(15,205)	(15,527)	(4,673)	(3,719)	(4,041)	632	4
5	CPUC Jurisdictional Revenue	4,806,054	5,223,599	4,848,308	5,043,273	417,545	42,254	237,219	(180,326)	5
6	Less: Other Operating Revenue	(91,759)	(114,764)	(113,861)	(116,243)	(23,005)	(22,102)	(24,484)	(1,479)	6
7	Total Billed Revenue	4,714,295	5,108,835	4,734,447	4,927,030	394,540	20,152	212,735	(181,805)	7
OPERATING EXPENSES										
8	*Energy Costs	0	0	0	0	0	0	0	0	8
9	*Other Production	380,048	451,388	400,732	445,018	71,340	20,685	64,971	(6,370)	9
10	*Storage	0	0	0	0	0	0	0	0	10
11	*Transmission	8,972	9,537	10,118	9,537	565	1,146	565	0	11
12	*Distribution	585,609	632,767	590,135	624,690	47,158	4,526	39,081	(8,077)	12
13	*Customer Accounts	418,454	422,235	413,576	415,632	3,781	(4,878)	(2,822)	(6,604)	13
14	Uncollectibles	9,623	14,432	12,477	12,998	4,809	2,854	3,375	(1,435)	14
15	*Customer Services	5,749	15,479	11,857	15,479	9,730	6,108	9,730	0	15
16	*Administrative and General	653,501	742,168	642,869	709,398	88,667	(10,632)	55,897	(32,771)	16
17	Franchise Requirements	38,339	41,735	38,778	40,345	3,396	439	2,006	(1,391)	17
18	Amortization	8,326	6,476	6,476	6,476	(1,850)	(1,850)	(1,850)	0	18
19	Wage Change Impacts	0	0	0	0	0	0	0	0	19
20	Other Price Change Impacts	0	0	0	0	0	0	0	0	20
21	*Other Adjustments	(7,457)	(696)	0	(696)	6,761	7,457	6,761	0	21
22	Subtotal Expenses	2,101,164	2,335,520	2,127,018	2,278,874	234,356	25,854	177,711	(56,646)	22
TAXES										
23	Superfund	0	0	0	0	0	0	0	0	23
24	Property	136,795	146,364	146,062	146,337	9,569	9,267	9,542	(27)	24
25	Payroll	68,442	80,799	75,677	80,243	12,357	7,235	11,801	(556)	25
26	Business	696	830	824	829	134	128	133	(1)	26
27	Other	415	232	230	232	(183)	(185)	(183)	(0)	27
28	State Corporation Franchise	97,668	113,821	103,206	103,489	16,153	5,538	5,821	(10,332)	28
29	Federal Income	463,129	444,841	420,601	431,049	(18,288)	(42,528)	(32,080)	(13,792)	29
30	Total Taxes	767,145	786,887	746,601	762,179	19,742	(20,544)	(4,966)	(24,708)	30
31	Depreciation	838,457	1,023,966	938,741	941,582	185,509	100,284	103,125	(82,384)	31
32	Fossil Decommissioning	28,394	(26,812)	(33,994)	(26,812)	(55,206)	(62,388)	(55,206)	0	32
33	Nuclear Decommissioning	0	0	0	0	0	0	0	0	33
34	Total Operating Expenses	3,735,159	4,119,561	3,778,365	3,955,823	384,402	43,206	220,664	(163,738)	34
35	Net for Return	1,082,117	1,120,197	1,085,148	1,102,977	38,080	3,031	20,860	(17,220)	35
36	Rate Base	12,311,492	12,746,024	12,347,220	12,550,083	434,532	35,728	238,591	(195,940)	36
RATE OF RETURN										
37	On Rate Base	8.79%	8.79%	8.79%	8.79%	0.00%	0.00%	0.00%	0.00%	37
38	On Equity	11.35%	11.35%	11.35%	11.35%	0.00%	0.00%	0.00%	0.00%	38

APPENDIX B

Summary of Increase by Electric, Gas Distribution, and Generation

(See Appendix G for Detail)

PACIFIC GAS AND ELECTRIC COMPANY SUMMARY OF INCREASE OVER ESTIMATED AUTHORIZED REVENUES (Millions of Dollars)

Comparison Exhibit (PG&E-79)					Difference from 2006 Authorized					
Line		2006 Authorized (A)	PG&E 2007 Proposed (B)	DRA 2007 Proposed (C)	Settlement (D)	PG&E (E) = (B) - (A)	DRA (F) = (C) - (A)	Settlement (G) = (D) - (A)	PG&E Reduction (H) = (G) - (E)	Line
<u>Electric Distribution</u>										
1	Operation and Maintenance	443.9	494.2	461.7	488.8	50.3	17.8	44.9	(5.4)	1
2	Customer Services	237.6	250.7	245.1	246.8	13.1	7.6	9.2	(3.9)	2
3	Administrative and General (incl Other Adj)	317.0	353.1	306.1	337.5	36.1	(10.8)	20.5	(15.6)	3
4	Payroll Taxes, Franchise & Uncollectibles	58.1	70.0	65.4	68.0	11.9	7.4	9.9	(2.0)	4
5	Return, Taxes & Depreciation	1,670.3	1,918.1	1,824.6	1,824.6	247.8	154.3	154.3	(93.5)	5
6	Subtotal	2,726.7	3,086.0	2,903.0	2,965.6	359.2	176.2	238.9	(120.4)	6
7	Less: FERC Allocation	(11.5)	(16.2)	(15.2)	(15.5)	(4.7)	(3.7)	(4.0)	0.6	7
8	Total CPUC Jurisdiction	2,715.3	3,069.8	2,887.8	2,950.1	354.5	172.5	234.8	(119.7)	8
9	Less: Other Operating Revenue	(67.3)	(79.1)	(79.0)	(80.1)	(11.8)	(11.7)	(12.8)	(1.0)	9
10	Billed Revenue	2,648.0	2,990.8	2,808.8	2,870.0	342.8	160.9	222.0	(120.8)	10
<u>Gas Distribution</u>										
11	Operation and Maintenance	138.8	142.5	133.0	139.9	3.7	(5.9)	1.0	(2.7)	11
12	Customer Services	186.6	187.0	180.3	184.3	0.4	(6.3)	(2.3)	(2.7)	12
13	Administrative and General (incl Other Adj)	183.1	197.7	171.4	189.0	14.6	(11.7)	5.9	(8.7)	13
14	Payroll Taxes, Franchise & Uncollectibles	31.0	35.1	33.1	34.5	4.0	2.0	3.5	(0.6)	14
15	Return, Taxes & Depreciation	503.6	526.0	509.5	525.8	22.5	5.9	22.2	(0.3)	15
16	Subtotal	1,043.2	1,088.4	1,027.2	1,073.4	45.2	(16.0)	30.3	(15.0)	16
17	Less: Other Operating Revenue	(16.3)	(26.0)	(25.6)	(26.0)	(9.7)	(9.3)	(9.7)	-	17
18	Billed Revenue	1,026.9	1,062.4	1,001.6	1,047.4	35.5	(25.3)	20.5	(15.0)	18
<u>Electric Generation</u>										
19	Operation and Maintenance	384.5	457.0	406.3	450.6	72.5	21.9	66.2	(6.4)	19
20	Customer Services	-	-	-	-	-	-	-	-	20
21	Administrative and General (incl Other Adj)	153.5	190.7	165.3	182.3	37.2	11.9	28.8	(8.4)	21
22	Payroll Taxes, Franchise & Uncollectibles	28.4	33.0	29.5	32.1	4.5	1.1	3.7	(0.8)	22
23	Return, Taxes & Depreciation	481.3	384.8	332.1	354.7	(96.5)	(149.1)	(126.5)	(30.0)	23
24	Subtotal	1,047.6	1,065.4	933.3	1,019.8	17.8	(114.3)	(27.8)	(45.6)	24
25	Less: Other Operating Revenue	(8.2)	(9.7)	(9.3)	(10.1)	(1.5)	(1.2)	(2.0)	(0.4)	25
26	Billed Revenue	1,039.4	1,055.7	924.0	1,009.6	16.3	(115.5)	(29.8)	(46.1)	26
<u>Total</u>										
27	Operation and Maintenance	967.2	1,093.7	1,001.0	1,079.2	126.5	33.8	112.1	(14.4)	27
28	Customer Services	424.2	437.7	425.4	431.1	13.5	1.2	6.9	(6.6)	28
29	Administrative and General (incl Other Adj)	653.5	741.5	642.9	708.7	88.0	(10.6)	55.2	(32.8)	29
30	Payroll Taxes, Franchise & Uncollectibles	117.5	138.0	128.0	134.6	20.5	10.5	17.1	(3.4)	30
31	Return, Taxes & Depreciation	2,655.1	2,828.9	2,666.2	2,705.1	173.7	11.1	49.9	(123.8)	31
32	Subtotal	4,817.5	5,239.8	4,863.5	5,058.8	422.2	46.0	241.3	(181.0)	32
33	Less: FERC Allocation	(11.5)	(16.2)	(15.2)	(15.5)	(4.7)	(3.7)	(4.0)	0.6	33
34	Total CPUC Jurisdiction	4,806.1	5,223.6	4,848.3	5,043.3	417.5	42.3	237.2	(180.3)	34
35	Less: Other Operating Revenue	(91.8)	(114.8)	(113.9)	(116.2)	(23.0)	(22.1)	(24.5)	(1.5)	35
36	Billed Revenue	4,714.3	5,108.8	4,734.4	4,927.0	394.5	20.2	212.7	(181.8)	36

Appendix C

Humboldt Bay Power Plant Projects Subject to Memorandum Account Tracking

Pacific Gas and Electric Company
2007 General Rate Case
Humboldt Bay Power Plant Projects Subject to Memorandum Account Tracking
(Thousands of Dollars)

Line	Description	MWC	2007	2008	2009	Line
1	Expense - 361b Survey Studies		1,051	404	-	1
	Capital Expenditures					
	Description					
2	HBPP 316b Modifications of Intake Structure	12	-	221	3,416	2
3	HBPP MEPP 2 Fire Suppression System Replace	81	-	-	466	3
4	HBPP MEPP 3 Fire Suppression System Replace	81	-	-	466	4
5	U1 HBPP NOx Reduction SB 656 (PM10)	81	2,168	-	-	5
6	U2 HBPP NOx Reduction SB 656 (PM10)	81	-	-	2,245	6
7	HBPP U2 Replace FWH Control Valves	81	-	25	98	7
8	HBPP U2 Replace Super heater	81	-	127	1,078	8
9	HBPP U1 Replace FWH Control Valves	81	-	-	25	9
10	HBPP U1Purchase/Install 2.4kV Switchgear	81	-	-	74	10
11	HBPP U1 Replace Condensate Control Valve	81	-	-	25	11
12	Total Capital Expenditures		2,168	373	7,893	12
13	Total Estimated Revenue Requirement		1,341	876	709	13

Appendix D

Settlement Net Salvage Rate Changes

Pacific Gas and Electric Company
2007 General Rate Case
SETTLEMENT NET SALVAGE RATES

<u>Line</u>	<u>FERC Acct</u>	<u>Asset Class</u>	<u>PG&E Proposal NS%</u>	<u>DRA Proposal NS%</u>	<u>PG&E/DRA Settlement NS%</u>	<u>Line</u>
<u>Electric Generation Plant</u>						
1		EHP Electric Hydro Production	-13%	-9%	-13%	1
<u>Electric Transmission Plant- Non Network</u>						
2	353	ETP35301 Station Equipment	-30%	-10%	-23%	2
3	354	ETP35400 Towers and Fixtures	-50%	-40%	-46%	3
4	355	ETP35500 Poles and Fixtures	-80%	-70%	-67%	4
<u>Electric Distribution Plant</u>						
5	364	EDP36400 Poles Towers and Fixtures	-100%	-85%	-80%	5
6	365	EDP36500 OH Conductor & Devices	-100%	-80%	-77%	6
7	367	EDP36700 Underground Conduct & Devices	-40%	-35%	-30%	7
<u>Gas Distribution Plant</u>						
8	376	GDP37601 Mains	-50%	-45%	-50%	8
9	380	GDP38000 Services	-100%	-90%	-100%	9

Note:

The above table only includes accounts where the net salvage differs from DRA

Appendix E

Settlement Attrition Summary

APPENDIX E - Settlement Attrition Summary (Errata)

(Millions of Dollars)

Pacific Gas and Electric Company

2007 General Rate Case

Attrition Summary

(Millions of Dollars)

Line	2008			2009			2010
	PG&E	DRA	Settlement	PG&E	DRA	Settlement	Settlement
1 Attrition Revenues	184	141		236	187		
2 Transformation Net Savings*	(41)	(41)		(56)	(56)		
3 Total Base Attrition Revenues	143	100	125	180	131	125	125
4 DCCP 2nd Refueling (one-time revenues)			0			35	(35)
5 Total Adjusted Attrition Revenues			125			160	90

* Transformation Savings: For 2009, the annual savings are \$97 million, which includes \$41 million in savings from 2008 and an incremental \$56 million in savings for 2009.

Allocation of Settlement Attrition Revenues by Electric and Gas Distribution, Generation

(allocated based on 2007 CPUC Billed Revenue)

	2008	2009	2010
6 Electric Distribution	63	63	63
7 Gas Distribution	22	22	22
8 Electric Generation	40	75	5
9 Total Attrition Revenues	125	160	90
10 % Increase over 2007 GRC Proposed Settlement Billed Revenues	2.5%	3.2%	1.7%

Appendix F

O&M Labor Factors

Pacific Gas and Electric Company
2007 General Rate Case
O&M LABOR FACTORS BY UNBUNDLED COST CATEGORY
(Thousands of 2004 Dollars)

Line	Unbundled Cost Category	Recorded Adjusted 2004		Line
		\$	Percentage	
	Electric Generation			
1	EG - Fossil Facilities (1)	10,849	1.19%	1
2	EG - Fossil Transmission (2)	178	0.02%	2
3	EG - Hydro Facilities (3)	40,660	4.47%	3
4	EG - Hydro Transmission (4)	2,429	0.27%	4
5	EG - Diablo Canyon Power Plant (5)	138,227	15.18%	5
6	EG - Diablo Canyon Transmission (6)	-	0.00%	6
7	EG - Purchased Power Payments (8)	-	0.00%	7
8	EG - Electric Supply Administration (14)	14,326	1.57%	8
9		<u>206,669</u>	<u>22.70%</u>	9
10	Nuclear Decommissioning			10
11	ND - Nuclear Decomm. (SAFSTOR) (7)	4,632	0.51%	11
12		<u>4,632</u>	<u>0.51%</u>	12
13	Electric Transmission			13
14	ET - EI Trans High Voltage (9)	29,073	3.19%	14
15	ET - EI Trans Low Voltage (10)	29,713	3.26%	15
16	ET - Third-Party Generation-Ties (11)	498	0.05%	16
17	ET - Partnership Generation-Ties (12)	29	0.00%	17
18		<u>59,313</u>	<u>6.51%</u>	18
19	Electric Distribution			19
20	ED - Wires and Services (13)	360,413	39.58%	20
21	ED - Trans. Level Direct Connects (15)	306	0.03%	21
22	ED - Electric Public Purpose Program Admin. (16) see note 1	21,916	2.41%	22
23		<u>382,635</u>	<u>42.02%</u>	23
24	Electric Public Purpose Program			24
25	EP - Electric Public Purpose Programs Costs (17)	-	0.00%	25
26	SPARE (18)	-	0.00%	26
27		<u>-</u>	<u>0.00%</u>	27
28				28
29	Electric Total	653,249	71.74%	29
30				30
31	Gas Transmission			31
32	GT - Gas Gathering (19)	2,694	0.30%	32
33	GT - Gas Storage (20)	5,024	0.55%	33
34	GT - Gas Local Transmission (21)	2,129	0.23%	34
35	GT - Gas Local Transmission Line 401 (22)	2,156	0.24%	35
36	GT - Gas Transmission: Backbone (23)	30,919	3.40%	36
37	GT - Gas Transmission: Customer Access Charge (24)	143	0.02%	37
38	GT - Gas Local Transmission: Line 401 Settlement Adjustment (25)	-	0.00%	38
39		<u>43,065</u>	<u>4.73%</u>	39
40	Gas Distribution			40
41	GD - Pipes and Services (26)	206,054	22.63%	41
42	GD - Gas Procurement Administration (27)	2,347	0.26%	42
43	GD - Gas Public Purpose Admin. (28) see note 1	5,862	0.64%	43
44		<u>214,263</u>	<u>23.53%</u>	44
45	Gas Public Purpose Programs			45
46	GP - Gas Public Purpose Programs Costs (29)	-	0.00%	46
47		<u>-</u>	<u>0.00%</u>	47
48				48
49	Gas Total	257,328	28.26%	49
50				50
51	Company Total	910,577	100.00%	51

Note 1 - PPP Admin costs are transferred from the program for allocation purposes and are not collected in the case

Appendix G

Settlement Comparison Exhibit – Results of Operations

This section contains tables showing summaries of proposed revenues and results of operations calculations, comparing PG&E and DRA's Comparison Exhibit positions with the Settlement.

Description	Table
Electric Distribution	
Revenues at Present and Proposed Rates Summary	1-1
Results of Operations	1-2
Income Tax Summary	1-3
Expense Summary	1-4
Franchise Fees and Uncollectible Accounts Expense	1-5
Taxes Other than Income	1-6
Plant in Service	1-7
Depreciation	1-8
Determination of Average Amounts of Working Cash	1-9
Rate Base	1-10
Net to Gross Multiplier	1-11
Gas Distribution	
Revenues at Present and Proposed Rates Summary	2-1
Results of Operations	2-2
Income Tax Summary	2-3
Expense Summary	2-4
Franchise Fees and Uncollectible Accounts Expense	2-5
Taxes Other than Income	2-6
Plant in Service	2-7
Depreciation	2-8
Determination of Average Amounts of Working Cash	2-9
Rate Base	2-10
Net to Gross Multiplier	2-11
Electric Generation	
Revenues at Present and Proposed Rates Summary	3-1
Results of Operations	3-2
Income Tax Summary	3-3
Expense Summary	3-4
Franchise Fees and Uncollectible Accounts Expense	3-5

Taxes Other than Income	3-6
Plant in Service	3-7
Depreciation	3-8
Determination of Average Amounts of Working Cash	3-9
Rate Base	3-10
Net Plant Additions and Capital Expenditures	4-1

Table 1-1
2007 General Rate Case
Revenue Summary – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
<u>REVENUES AT PRESENT RATES</u>						
<u>CPUC Revenues (Retail)</u>						
1	Revenues from Sales	2,557,932	2,557,932	0	2,557,932	0
2	Plus: Non-Applicable Revenue	90,027	90,027	0	90,027	0
3	CPUC Revenue	2,647,959	2,647,959	0	2,647,959	0
4	Plus: Adopted Other Operating Revenue	67,300	67,300	0	67,300	0
5	Rate Case Revenue	2,715,259	2,715,259	0	2,715,259	0
<u>FERC Revenues (Wholesale)</u>						
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	0	0
8	FERC Revenue	0	0	0	0	0
9	Plus: Other Operating Revenue	14,344	14,344	0	14,344	0
10	Rate Case Revenue	14,344	14,344	0	14,344	0
11	Total Rate Case Revenue	2,729,603	2,729,603	0	2,729,603	0
<u>INCREASE IN RATE CASE REVENUE</u>						
12	CPUC Jurisdiction	354,546	234,814	(119,732)	172,524	62,290
13	FERC Jurisdiction	1,815	1,183	(632)	863	320
14	Total Increase	356,361	235,997	(120,364)	173,387	62,610
15	Percent	13.06%	8.65%		6.35%	
<u>INCREASE IN CPUC Revenue from Sales</u>						
16	Amount	342,796	222,015	(120,780)	160,864	61,151
17	Percent	13.40%	8.68%		6.29%	
<u>REVENUES AT PROPOSED RATES</u>						
<u>CPUC Revenues (Retail)</u>						
18	Revenues from Sales	2,900,728	2,779,947	(120,780)	2,718,796	61,151
19	Plus: Non-Applicable Revenue	90,027	90,027	0	90,027	0
20	CPUC Revenue	2,990,755	2,869,974	(120,780)	2,808,823	61,151
21	Plus: Other Operating Revenue	79,050	80,099	1,048	78,960	1,139
22	Rate Case Revenue	3,069,805	2,950,073	(119,732)	2,887,783	62,290
<u>FERC Revenues (Wholesale)</u>						
23	Revenues from Sales	1,815	1,183	(632)	863	320
24	Plus: Non-Applicable Revenue	0	0	0	0	0
25	FERC Revenue	1,815	1,183	(632)	863	320
26	Plus: Other Operating Revenue	14,344	14,344	0	14,344	0
27	Rate Case Revenue	16,159	15,527	(632)	15,207	320
28	Total Rate Case Revenue	3,085,964	2,965,600	(120,364)	2,902,990	62,610

Table 1-2
2007 General Rate Case
Results of Operations – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
REVENUE						
1	Revenue at Effective Rates	2,995,937	2,875,573	(120,364)	2,812,963	62,610
2	Less Non-General Revenue	90,027	90,027	0	90,027	0
3	= General Rate Case Revenue	3,085,964	2,965,600	(120,364)	2,902,990	62,610
OPERATING EXPENSES						
4	Energy Costs	0	0	0	0	0
5	Other Production	0	0	0	0	0
6	Storage	0	0	0	0	0
7	Transmission	726	726	0	726	0
8	Distribution	493,447	488,040	(5,406)	460,970	27,070
9	Customer Accounts	247,298	243,421	(3,877)	241,763	1,658
10	Uncollectibles	8,539	7,655	(884)	7,482	173
11	Customer Services	3,373	3,373	0	3,369	4
12	Administrative & General	353,399	337,795	(15,605)	306,116	31,679
13	Franchise Requirements	23,356	22,449	(907)	21,975	474
14	Amortization	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(332)	(332)	0	0	(332)
18	Subtotal Expenses	1,129,805	1,103,127	(26,678)	1,042,401	60,726
TAXES						
19	Superfund	0	0	0	0	0
20	Property	97,415	97,402	(13)	97,215	188
21	Payroll	37,611	37,409	(202)	35,475	1,934
22	Business	386	386	0	386	0
23	Other	108	108	0	108	0
24	State Corp. Franchise	79,233	70,978	(8,254)	72,663	(1,684)
25	Federal Income	311,480	306,024	(5,456)	303,608	2,416
26	Total Taxes	526,233	512,308	(13,925)	509,455	2,853
27	DEPRECIATION	678,883	596,774	(82,109)	608,035	(11,260)
28	Fossil Decommissioning	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	2,334,921	2,212,210	(122,712)	2,159,890	52,319
31	NET FOR RETURN	751,042	753,390	2,348	743,099	10,291
32	RATE BASE	8,545,639	8,572,359	26,720	8,455,263	117,096
RATE OF RETURN						
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 1-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Distribution
(\$000)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	3,085,964	2,965,600	(120,364)	2,902,990	62,610
2	O&M Expenses	1,129,805	1,103,127	(26,678)	1,042,401	60,726
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	135,520	135,305	(215)	133,184	2,122
6	Subtotal	1,820,638	1,727,167	(93,471)	1,727,405	(238)
DEDUCTIONS FROM TAXABLE INCOME						
7	Interest Charges	236,646	237,386	740	234,143	3,243
8	Fiscal/Calendar Adjustment	2,470	2,458	(13)	2,272	186
9	Operating Expense Adjustments	(21,961)	(21,961)	0	(21,958)	(4)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(1,492)	(1,492)	0	(1,492)	0
13	Capitalized Other	(594)	(594)	0	(594)	0
14	Subtotal Deductions	215,069	215,796	727	212,371	3,425
CCFT TAXES						
15	State Operating Expense Adjustment	5,433	5,433	0	5,433	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	590,918	590,095	(823)	578,800	11,295
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	60,071	60,071	0	56,522	3,550
20	Repair Allowance	53,843	53,843	0	53,296	548
21	Subtotal Deductions	925,334	925,239	(96)	906,421	18,817
22	Taxable Income for CCFT	895,303	801,929	(93,375)	820,984	(19,055)
23	CCFT	79,145	70,890	(8,254)	72,575	(1,684)
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	79,145	70,890	(8,254)	72,575	(1,684)
26	Defense Facilities Credit	0	0	0	0	0
27	Deferred Taxes - Interest	220	220	0	220	0
28	Deferred Taxes - Vacation	(132)	(132)	0	(132)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	0	0	0	0	0
31	Total CCFT	79,233	70,978	(8,254)	72,663	(1,684)
FEDERAL TAXES						
32	CCFT - Prior Year	52,955	52,996	40	53,193	(197)
33	Federal Operating Expense Adjustment	5,688	5,688	0	5,688	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	583,458	582,635	(823)	569,071	13,564
37	Federal Tax Depreciation - Other	0	0	0	0	0

Table 1-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Distribution
(\$000)

Line No.	Description			Settlmt. +/- than		
		PG&E	Settlement	PG&E	DRA	Settlmt. +/- than DRA
38	Removal Costs	60,071	60,071	0	56,522	3,550
39	Repair Allowance	28,992	28,992	0	28,697	295
40	Preferred Dividend Credit	311	311	0	311	0
41	Subtotal Deductions	946,544	946,489	(56)	925,852	20,637
42	Taxable Income for FIT	874,094	780,679	(93,415)	801,553	(20,874)
43	Federal Income Tax	305,933	273,238	(32,695)	280,544	(7,306)
44	Defense Facilities Credit	0	0	0	0	0
45	Flowback of Excess Deferred Taxes	0	0	0	0	0
46	Deferred Taxes - Interest	858	858	0	858	0
47	Deferred Taxes - Vacation	(476)	(476)	0	(476)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	5,165	32,405	27,240	22,683	9,722
50	Total Federal Income Tax	311,480	306,024	(5,456)	303,608	2,416

Table 1-4
2007 General Rate Case
Expense Summary - Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
Expenses in 2004 Dollars						
1	Production (Generation)					
2	Labor	0	0	0	0	0
3	Materials and Services	0	0	0	0	0
4	Other	0	0	0	0	0
5	Total	0	0	0	0	0
6	Transmission					
7	Labor	353	353	0	353	0
8	Materials and Services	290	290	0	290	0
9	Other	25	25	0	25	0
10	Total	669	669	0	669	0
11	Distribution					
12	Labor	209,152	208,461	(691)	201,150	7,311
13	Materials and Services	249,346	244,946	(4,400)	226,928	18,019
14	Other	0	0	0	0	0
15	Total	458,498	453,407	(5,091)	428,077	25,330
16	Customer Accounts					
17	Labor	154,615	152,962	(1,653)	152,494	468
18	Materials and Services	58,803	56,919	(1,884)	55,873	1,046
19	Other	12,898	12,898	0	12,898	0
20	Total	226,316	222,780	(3,537)	221,265	1,514
21	Customer Service					
22	Labor	2,563	2,563	0	2,562	1
23	Materials and Services	505	505	0	502	3
24	Other	0	0	0	0	0
25	Total	3,069	3,069	0	3,065	4
26	Administrative and General					
27	Labor	69,059	69,059	0	54,440	14,619
28	Materials and Services	67,715	53,428	(14,287)	45,154	8,274
29	Other	126,944	126,944	0	126,911	33
30	Wage Related	13,771	13,771	0	13,771	0
31	Medical	61,331	61,331	0	54,812	6,519
32	Total	338,820	324,533	(14,287)	295,088	29,445
33	Total Expenses in 2004 Dollars					
34	Labor	435,743	433,399	(2,344)	410,999	22,399
35	Materials and Services	376,659	356,088	(20,571)	328,747	27,341
36	Other	139,868	139,868	0	139,835	33
37	Wage Related	13,771	13,771	0	13,771	0
38	Medical	61,331	61,331	0	54,812	6,519

Table 1-4
2007 General Rate Case
Expense Summary - Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
39	Total	1,027,372	1,004,457	(22,915)	948,164	56,293
40	Total Expenses in 2007 Dollars					
41	Labor	479,593	477,014	(2,580)	452,360	24,654
42	Materials and Services	401,961	379,654	(22,308)	350,781	28,873
43	Other	139,868	139,868	0	139,835	33
44	Wage Related	15,157	15,157	0	15,157	0
45	Medical	61,331	61,331	0	54,812	6,519
46	Total	1,097,911	1,073,023	(24,888)	1,012,944	60,079

Table 1-5
2007 General Rate Case
Franchise Fees and Uncollectible Accounts Expenses - Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	<u>Revenue</u>					
2	Rate Case Revenues	3,085,964	2,965,600	(120,364)	2,902,990	62,610
3	Percent Of Revenue From Customers	99.8200%	99.8200%	99.8200%	99.8200%	99.8200%
4	Rate Case Revenues From Customers	3,080,409	2,960,262	(120,147)	2,897,764	62,498
	<u>Uncollectible Accounts</u>					
6	Uncollectible Rate	0.002772	0.002586	0.007355	0.002582	0.002771
7	Uncollectible Accounts Expense	8,539	7,655	(884)	7,482	173
8	<u>Franchise Fees</u>					
9	Rate Case Revenues From Customers	3,080,409	2,960,262	(120,147)	2,897,764	62,498
10	Uncollectible Accounts Expense	8,539	7,655	(884)	7,482	173
11	Net Rate Case Revenue From Customers	3,071,870	2,952,607	(119,263)	2,890,282	62,324
12	Franchise Rate	0.007603	0.007603	0.007603	0.007603	0.007603
13	Franchise Fees Expense	23,356	22,449	(907)	21,975	474

Table 1-6
2007 General Rate Case
Taxes Other than Income - Test Year 2007
Electric Distribution
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>PG&E</u>	<u>Settlement</u>	<u>Settlmt. +/- than PG&E</u>	<u>DRA</u>	<u>Settlmt. +/- than DRA</u>
1	Property (Ad Valorem) Tax	97,415	97,402	(13)	97,215	188
2	Federal Insurance Contribution Act	32,642	32,466	(176)	30,788	1,678
3	Federal Unemployment Insurance	398	396	(2)	375	20
4	State Unemployment Insurance	2,039	2,028	(11)	1,923	105
5	San Francisco Payroll Tax	2,532	2,519	(14)	2,388	131
6	Total Payroll Taxes	37,611	37,409	(202)	35,475	1,934
7	Other Taxes	494	495	0	494	0
8	Total Taxes Other Than Income	135,520	135,305	(215)	133,184	2,122

Table 1-7
Plant in Service – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	13,848,856	13,848,856	0	13,848,856	0
3	Common, General, and Intangible	1,402,212	1,402,212	0	1,402,212	0
4	Total 2004 End-of-Year Plant	15,251,069	15,251,069	0	15,251,069	0
5	2005 Full-Year Net Additions					
6	Functional	596,079	596,079	0	595,833	246
7	Common, General, and Intangible	(43,354)	(43,354)	0	(43,342)	(12)
8	Total 2005 Net Additions	552,725	552,725	0	552,492	234
9	2005 End-of-Year Plant					
10	Functional	14,444,935	14,444,935	0	14,444,690	246
11	Common, General, and Intangible	1,358,859	1,358,859	0	1,358,871	(12)
12	Total 2005 End-of-Year Plant	15,803,794	15,803,794	0	15,803,560	234
13	2006 Full-Year Net Additions					
14	Functional	664,611	664,611	0	638,748	25,863
15	Common, General, and Intangible	69,317	66,845	(2,473)	61,154	5,690
16	Total 2006 Net Additions	733,929	731,456	(2,473)	699,903	31,553
17	2006 End-of-Year Plant					
18	Functional	15,109,547	15,109,547	0	15,083,438	26,109
19	Common, General, and Intangible	1,428,176	1,425,703	(2,473)	1,420,025	5,678
20	Total 2006 End-of-Year Plant	16,537,722	16,535,250	(2,473)	16,503,463	31,787
21	2007 Full-Year Net Additions					
22	Functional	731,135	731,135	0	690,371	40,764
23	Common, General, and Intangible	(34,203)	(34,203)	0	(51,305)	17,102
24	Total 2007 Net Additions	696,932	696,932	0	639,066	57,866
25	2007 End-of-Year Plant					
26	Functional	15,840,682	15,840,682	0	15,773,809	66,872
27	Common, General, and Intangible	1,393,973	1,391,500	(2,473)	1,368,720	22,781
28	Total 2007 End-of-Year Plant	17,234,654	17,232,182	(2,473)	17,142,529	89,653
29	2007 Weighted Average Net Additions					
30	Functional	337,137	337,137	0	321,579	15,558
31	Common, General, and Intangible	(64,637)	(64,637)	0	(71,401)	6,763
32	Total 2007 Weighted Average Net Additions	272,499	272,499	0	250,178	22,321
33	2007 Weighted Average Plant					
34	Functional	15,446,683	15,446,683	0	15,405,017	41,667
35	Common, General, and Intangible	1,363,538	1,361,066	(2,473)	1,348,624	12,441
36	Total 2007 Weighted Average Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108

Table 1-8
2007 General Rate Case
Depreciation – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
<u>Depreciation</u>						
1	Production	4	4	-	4	-
2	Transmission	645	628	(17)	645	(17)
3	Distribution	611,385	529,459	(81,926)	541,708	(12,249)
4	General	3,077	3,077	-	3,086	(10)
5	Subtotal	615,111	533,167	(81,944)	545,443	(12,276)
6	Common Utility Allocation	63,697	63,532	(165)	62,516	1,016
7	Total	678,808	596,699	(82,109)	607,960	(11,260)
<u>Depreciation Reserve</u>						
8	Production	202	202	-	202	-
9	Transmission	11,947	11,929	(17)	11,947	(17)
10	Distribution	6,854,387	6,772,460	(81,926)	6,795,933	(23,473)
11	General	31,786	31,786	-	31,996	(209)
12	Subtotal	6,898,321	6,816,377	(81,944)	6,840,076	(23,699)
13	Common Utility Allocation	511,222	510,954	(268)	540,814	(29,859)
14	Total	7,409,543	7,327,332	(82,212)	7,380,890	(53,559)
<u>Weighted Average Depreciation Reserve</u>						
8	Production	200	200	-	200	-
9	Transmission	11,624	11,615	(9)	11,624	(9)
10	Distribution	6,617,361	6,576,398	(40,963)	6,589,299	(12,901)
11	General	34,198	34,198	-	34,403	(204)
12	Subtotal	6,663,383	6,622,411	(40,972)	6,635,525	(13,114)
13	Common Utility Allocation	530,289	530,103	(185)	541,498	(11,394)
14	Total	7,193,672	7,152,515	(41,157)	7,177,023	(24,509)

Table 1-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors
- Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	0	0	0	0	0
2	Special Deposits and Working Funds	106	106	(0)	106	0
3	Other Receivables	50,952	50,911	(41)	50,908	2
4	Prepayments	6,555	6,555	0	6,555	0
5	Deferred Debits, Company-Wide	(356)	(355)	0	(355)	(0)
	Less					
6	Working Cash Capital not Supplied by Investors	3,892	3,892	0	3,892	(0)
7	Goods Delivered to Construction Sites	1,523	1,523	0	1,523	0
8	Accrued Vacation	68,438	68,070	(368)	64,552	3,518
	Add					
9	Prepayment, Departmental	9,829	9,829	0	9,829	0
10	Total Operational Cash Requirement	(6,767)	(6,439)	327	(2,924)	(3,516)
	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	59,161	60,380	1,219	12,158	48,222
12	Working Cash Capital Supplied by Investors	52,394	53,941	1,547	9,234	44,706

Table 1-10
2007 General Rate Case
Rate Base – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
WEIGHTED AVERAGE PLANT						
1	Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant - Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108
WORKING CAPITAL						
6	Material and Supplies - Fuel	0	0	0	0	0
7	Material and Supplies - Other	29,880	29,880	0	29,880	0
8	Working Cash	52,394	53,941	1,547	9,234	44,706
9	Total Working Capital	82,275	83,821	1,547	39,115	44,706
ADJUSTMENTS FOR TAX REFORM ACT						
10	Deferred Capitalized Interest	2,751	2,751	0	2,751	0
11	Deferred Vacation	22,661	22,661	0	22,661	0
12	Deferred CIAC Tax Effects	265,556	265,556	0	265,556	0
13	Total Adjustments	290,969	290,969	0	290,969	0
LESS DEDUCTIONS						
14	Customer Advances	95,939	95,939	0	95,939	0
15	Accumulated Deferred Taxes - Defense	0	0	0	0	0
16	Accumulated Deferred Taxes - Fixed Assets	1,292,286	1,305,797	13,512	1,299,571	6,227
17	Accumulated Deferred Taxes - Other	0	0	0	0	0
18	Deferred ITC	55,854	55,854	0	55,854	0
19	Deferred Tax - Other	0	0	0	0	0
20	Total Deductions	1,444,078	1,457,590	13,512	1,451,363	6,227
21	DEPRECIATION RESERVE	7,193,747	7,152,589	(41,157)	7,177,098	(24,509)
22	TOTAL RATE BASE	8,545,639	8,572,359	26,720	8,455,263	117,096

Table 1-11
2007 General Rate Case
Net To Gross Multiplier - Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue Base	1.000000	1.000000	0.000000	1.000000	0.000000
2	Less Interdepartmental Revenue	0.001800	0.001800	0.000000	0.001800	0.000000
3	Percent Revenue From Jurisdictional Customers	0.998200	0.998200	0.000000	0.998200	0.000000
4	Uncollectibles Percentage	0.002767	0.002581	(0.000186)	0.002577	0.000004
5	Franchise Requirements	0.007568	0.007570	0.000001	0.007570	(0.000000)
6	Total Uncollectibles and Franchise Requirements	0.010335	0.010151	(0.000184)	0.010147	0.000004
7	Net For State Income Taxes	0.989665	0.989849	0.000184	0.989853	(0.000004)
8	State Income Tax Percentage	0.088400	0.088400	0.000000	0.088400	0.000000
9	State Income Taxes	0.087486	0.087503	0.000016	0.087503	(0.000000)
10	Net For Federal Income Taxes	0.989665	0.989849	0.000184	0.989853	(0.000004)
11	Federal Income Tax Percentage	0.350000	0.350000	0.000000	0.350000	0.000000
12	Federal Income Taxes	0.346383	0.346447	0.000064	0.346449	(0.000001)
13	Net Operating Revenue	0.555796	0.555899	0.000103	0.555901	(0.000002)
14	Net To Gross Multiplier	1.799222	1.798887	(0.000335)	1.798880	0.000007

Table 2-1
2007 General Rate Case
Revenue Gas – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settltmt. +/- than PG&E	DRA	Settltmt. +/- than DRA
<u>REVENUES AT PRESENT RATES</u>						
<u>CPUC Revenues (Retail)</u>						
1	Revenues from Sales	1,026,891	1,026,891	0	1,026,891	0
2	Plus: Non-Applicable Revenue	0	0	0	0	0
3	CPUC Revenue	1,026,891	1,026,891	0	1,026,891	0
4	Plus: Adopted Other Operating Revenue	16,300	16,300	0	16,300	0
5	Rate Case Revenue	1,043,191	1,043,191	0	1,043,191	0
<u>FERC Revenues (Wholesale)</u>						
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	0	0
8	FERC Revenue	0	0	0	0	0
9	Plus: Other Operating Revenue	0	0	0	0	0
10	Rate Case Revenue	0	0	0	0	0
11	Total Rate Case Revenue	1,043,191	1,043,191	0	1,043,191	0
<u>INCREASE IN RATE CASE REVENUE</u>						
12	CPUC Jurisdiction	45,209	30,253	(14,955)	(15,989)	46,242
13	FERC Jurisdiction	0	0	0	0	0
14	Total Increase	45,209	30,253	(14,955)	(15,989)	46,242
15	Percent	4.33%	2.90%		(1.53%)	
<u>INCREASE IN CPUC REVENUE FROM SALES</u>						
16	Amount	35,485	20,530	(14,955)	(25,262)	45,792
17	Percent	3.46%	2.00%		(2.46%)	
<u>REVENUES AT PROPOSED RATES</u>						
<u>CPUC Revenues (Retail)</u>						
18	Revenues from Sales	1,062,376	1,047,421	(14,955)	1,001,629	45,792
19	Plus: Non-Applicable Revenue	0	0	0	0	0
20	CPUC Revenue	1,062,376	1,047,421	(14,955)	1,001,629	45,792
21	Plus: Other Operating Revenue	26,024	26,024	0	25,573	451
22	Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242
<u>FERC Revenues (Wholesale)</u>						
23	Revenues from Sales	0	0	0	0	0
24	Plus: Non-Applicable Revenue	0	0	0	0	0
25	FERC Revenue	0	0	0	0	0
26	Plus: Other Operating Revenue	0	0	0	0	0
27	Rate Case Revenue	0	0	0	0	0
28	Total Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242

Table 2-2
2007 General Rate Case
Results of Operations – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
REVENUE						
1	Revenue at Effective Rates	1,088,400	1,073,444	(14,955)	1,027,202	46,242
2	Less Non-General Revenue	0	0	0	0	0
3	General Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242
OPERATING EXPENSES						
4	Energy Costs	0	0	0	0	0
5	Other Production	0	0	0	0	0
6	Storage	0	0	0	0	0
7	Transmission	3,208	3,208	0	3,789	(581)
8	Distribution	139,320	136,650	(2,671)	129,165	7,485
9	Customer Accounts	174,938	172,211	(2,727)	171,813	398
10	Uncollectibles	2,946	2,710	(235)	2,589	121
11	Customer Services	12,106	12,106	0	8,488	3,618
12	Administrative and General	197,892	189,154	(8,738)	171,415	17,739
13	Franchise Requirements	10,316	10,177	(140)	9,738	438
14	Amortization	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(186)	(186)	0	0	(186)
18	Subtotal Expenses	540,539	526,028	(14,511)	496,997	29,031
TAXES						
19	Superfund	0	0	0	0	0
20	Property	24,423	24,416	(7)	24,353	63
21	Payroll	21,534	21,350	(184)	20,443	907
22	Business	221	221	(1)	223	(2)
23	Other	62	62	(0)	62	(1)
24	State Corporation Franchise	20,190	20,213	23	19,398	815
25	Federal Income	78,826	78,780	(47)	77,035	1,745
26	Total Taxes	145,256	145,041	(216)	141,514	3,527
27	DEPRECIATION	209,484	209,392	(92)	199,345	10,047
28	Fossil Decommissioning	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	895,280	880,461	(14,819)	837,856	42,605
31	Net for Return	193,120	192,984	(137)	189,346	3,637
32	Rate Base	2,197,395	2,195,839	(1,556)	2,154,456	41,383
RATE OF RETURN						
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 2-3
2007 General Rate Case
Income Tax Summary - Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than n PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	1,088,400	1,073,444	(14,955)	1,027,202	46,242
2	O&M Expenses	540,539	526,028	(14,511)	496,997	29,031
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	46,240	46,048	(192)	45,081	967
6	Subtotal	501,621	501,368	(253)	485,124	16,244
DEDUCTIONS FROM TAXABLE INCOME						
7	Interest Charges	60,850	60,807	(43)	59,661	1,146
8	Fiscal/Calendar Adjustment	542	535	(7)	474	62
9	Operating Expense Adjustments	(11,967)	(11,967)	0	(11,944)	(23)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(251)	(251)	0	(251)	0
13	Capitalized Other	(486)	(486)	0	(486)	0
14	Subtotal Deductions	48,689	48,638	(50)	47,453	1,185
CCFT TAXES						
15	State Operating Expense Adjustment	1,480	1,480	0	1,480	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	213,933	213,473	(461)	208,261	5,212
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	9,425	9,425	0	8,799	626
20	Repair Allowance	0	0	0	0	0
21	Subtotal Deductions	273,527	273,015	(511)	265,993	7,023
22	Taxable Income for CCFT	228,094	228,353	258	219,132	9,221
23	CCFT	20,164	20,186	23	19,371	815
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	20,164	20,186	23	19,371	815
26	Defense Facilities Credit	0	0	0	0	0
27	Deferred Taxes - Interest	48	48	0	48	0
28	Deferred Taxes - Vacation	(22)	(22)	0	(22)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	0	0	0	0	0
31	Total CCFT	20,190	20,213	23	19,398	815

Table 2-3
2007 General Rate Case
Income Tax Summary - Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than n PG&E	DRA	Settlmt. +/- than DRA
	FEDERAL TAXES					
32	CCFT - Prior Year	18,298	18,321	23	18,340	(19)
33	Federal Operating Expense Adjustment	1,639	1,639	0	1,639	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	229,757	229,296	(461)	222,496	6,800
37	Federal Tax Depreciation - Other	0	0	0	0	0
38	Removal Costs	9,425	9,425	0	8,799	626
39	Repair Allowance	0	0	0	0	0
40	Preferred Dividend Credit	40	40	0	40	0
41	Subtotal Deductions	307,849	307,360	(489)	298,768	8,592
42	Taxable Income for FIT	193,772	194,008	236	186,356	7,652
43	Federal Income Tax	67,820	67,903	83	65,225	2,678
44	Defense Facilities Credit	0	0	0	0	0
45	Flowback of Excess Deferred Taxes	0	0	0	0	0
46	Deferred Taxes - Interest	234	234	0	234	0
47	Deferred Taxes - Vacation	(80)	(80)	0	(80)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	10,853	10,723	(129)	11,657	(933)
50	Total Federal Income Tax	78,826	78,780	(47)	77,035	1,745

Table 2-4
2007 General Rate Case
Expense Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
Expenses in 2004 Dollars						
1	Production (Generation)					
2	Labor	0	0	0	0	0
3	Materials and Services	0	0	0	0	0
4	Other	0	0	0	0	0
5	Total	0	0	0	0	0
6	Transmission and Storage					
7	Labor	2,367	2,367	0	2,795	(429)
8	Materials and Services	566	566	0	669	(103)
9	Other	0	0	0	0	0
10	Total	2,932	2,932	0	3,464	(532)
11	Distribution					
12	Labor	98,866	97,856	(1,010)	95,289	2,567
13	Materials and Services	28,610	27,148	(1,462)	22,777	4,370
14	Other	0	0	0	0	0
15	Total	127,476	125,004	(2,472)	118,067	6,937
16	Customer Accounts					
17	Labor	108,250	107,129	(1,122)	107,303	(174)
18	Materials and Services	41,421	40,055	(1,366)	39,515	540
19	Other	10,553	10,553	0	10,553	0
20	Total	160,225	157,737	(2,488)	157,371	365
21	Customer Service					
22	Labor	1,328	1,328	0	972	356
23	Materials and Services	9,745	9,745	0	6,792	2,953
24	Other	0	0	0	0	0
25	Total	11,073	11,073	0	7,764	3,309
26	Administrative and General					
27	Labor	38,671	38,671	0	30,485	8,186
28	Materials and Services	37,918	29,918	(8,000)	25,285	4,633
29	Other	71,084	71,084	0	71,066	19
30	Wage Related	7,711	7,711	0	7,711	0
31	Medical	34,344	34,344	0	30,693	3,651
32	Total	189,728	181,727	(8,000)	165,239	16,488

Table 2-4
2007 General Rate Case
Expense Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
33	Total Expenses in 2004 Dollars					
34	Labor	249,481	247,349	(2,132)	236,843	10,506
35	Materials and Services	118,260	107,432	(10,829)	95,038	12,393
36	Other	81,638	81,638	0	81,619	19
37	Wage Related	7,711	7,711	0	7,711	0
38	Medical	34,344	34,344	0	30,693	3,651
39	Total	491,434	478,473	(12,960)	451,905	26,569
40	Total Expenses in 2007 Dollars					
41	Labor	274,588	272,241	(2,346)	260,678	11,563
42	Materials and Services	128,221	116,432	(11,789)	103,193	13,239
43	Other	81,638	81,638	0	81,619	19
44	Wage Related	8,487	8,487	0	8,487	0
45	Medical	34,344	34,344	0	30,693	3,651
46	Total	527,277	513,142	(14,135)	484,669	28,472

Table 2-5
2007 General Rate Case
Franchise Fees and Uncollectible Accounts Expense – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	<u>Revenue</u>					
2	Rate Case Revenues	1,088,400	1,073,444	(14,955)	1,027,202	46,242
3	Percent Of Revenue From Customers	97.6300%	97.6300%	97.6300%	97.6300%	97.6300%
4	Rate Case Revenues From Customers	1,062,605	1,048,004	(14,601)	1,002,858	45,146
5	<u>Uncollectible Accounts</u>					
6	Uncollectible Rate	0.002772	0.002586	0.016122	0.002582	0.002675
7	Uncollectible Accounts Expense	2,946	2,710	(235)	2,589	121
8	<u>Franchise Fees</u>					
9	Rate Case Revenues From Customers	1,062,605	1,048,004	(14,601)	1,002,858	45,146
10	Uncollectible Accounts Expense	2,946	2,710	(235)	2,589	121
11	Net Rate Case Revenue From Customers	1,059,659	1,045,294	(14,366)	1,000,268	45,025
12	Franchise Rate	0.009736	0.009736	0.009736	0.009736	0.009736
13	Franchise Fees Expense	10,316	10,177	(140)	9,738	438

Table 2-6
2007 General Rate Case
Taxes Other than Income - Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Property (Ad Valorem) Tax	24,423	24,416	(7)	24,353	63
2	Federal Insurance Contribution Act	18,689	18,529	(160)	17,742	787
3	Federal Unemployment Insurance	228	226	(2)	216	10
4	State Unemployment Insurance	1,167	1,157	(10)	1,108	49
5	San Francisco Payroll Tax	1,450	1,438	(12)	1,376	61
6	Total Payroll Taxes	21,534	21,350	(184)	20,443	907
7	Other Taxes	283	282	(1)	285	(3)
8	Total Taxes Other Than Income	46,240	46,048	(192)	45,081	967

Table 2-7
2007 General Rate Case
Plant in Service – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	4,649,137	4,649,137	0	4,649,137	0
3	Common, General, and Intangible	925,937	925,937	0	925,937	0
4	Total 2004 End-of-Year Plant	5,575,073	5,575,073	0	5,575,073	0
5	2005 Full-Year Net Additions					
6	Functional	175,811	175,811	0	175,811	0
7	Common, General, and Intangible	(13,432)	(13,432)	0	(13,517)	85
8	Total 2005 Net Additions	162,379	162,379	0	162,294	85
9	2005 End-of-Year Plant					
10	Functional	4,824,948	4,824,948	0	4,824,948	0
11	Common, General, and Intangible	912,505	912,505	0	912,420	85
12	Total 2005 End-of-Year Plant	5,737,453	5,737,453	0	5,737,367	85
13	2006 Full-Year Net Additions					
14	Functional	173,111	173,111	0	165,542	7,569
15	Common, General, and Intangible	40,365	38,981	(1,385)	35,919	3,062
16	Total 2006 Net Additions	213,477	212,092	(1,385)	201,461	10,631
17	2006 End-of-Year Plant					
18	Functional	4,998,059	4,998,059	0	4,990,490	7,569
19	Common, General, and Intangible	952,870	951,486	(1,385)	948,339	3,147
20	Total 2006 End-of-Year Plant	5,950,929	5,949,545	(1,385)	5,938,829	10,716
21	2007 Full-Year Net Additions					
22	Functional	180,682	180,682	0	170,348	10,333
23	Common, General, and Intangible	27,061	27,061	0	17,602	9,459
24	Total 2007 Net Additions	207,743	207,743	0	187,950	19,792
25	2007 End-of-Year Plant					
26	Functional	5,178,740	5,178,740	0	5,160,838	17,902
27	Common, General, and Intangible	979,931	978,547	(1,385)	965,941	12,606
28	Total 2007 End-of-Year Plant	6,158,672	6,157,287	(1,385)	6,126,779	30,508
29	2007 Weighted Average Net Additions					
30	Functional	91,493	91,493	0	86,327	5,167
31	Common, General, and Intangible	6,565	6,565	0	2,845	3,719
32	Total 2007 Weighted Average Net Additions	98,058	98,058	0	89,172	8,886
33	2007 Weighted Average Plant					
34	Functional	5,089,552	5,089,552	0	5,076,817	12,736
35	Common, General, and Intangible	959,435	958,050	(1,385)	951,184	6,866
36	Total 2007 Weighted Average Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602

Table 2-8
2007 General Rate Case
Depreciation – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
<u>Depreciation</u>						
1	Production	523	523	-	523	-
2	Transmission	152	152	-	152	-
3	Distribution	163,316	163,316	-	153,797	9,519
4	General	781	781	-	781	-
5	Subtotal	164,773	164,773	-	155,253	9,519
6	Common Utility Allocation	44,710	44,618	(92)	44,091	527
7	Total	209,483	209,391	(92)	199,344	10,047
<u>Depreciation Reserve</u>						
8	Production	4,470	4,470	-	4,470	-
9	Transmission	1,524	1,524	-	1,524	-
10	Distribution	3,246,020	3,246,020	-	3,238,852	7,169
11	General	8,211	8,211	-	8,211	-
12	Subtotal	3,260,226	3,260,226	-	3,253,057	7,169
13	Common Utility Allocation	419,069	418,919	(150)	435,702	(16,783)
14	Total	3,679,295	3,679,145	(150)	3,688,759	(9,615)
<u>Weighted Average Depreciation Reserve</u>						
8	Production	4,209	4,209	-	4,209	-
9	Transmission	1,447	1,447	-	1,447	-
10	Distribution	3,176,628	3,176,628	-	3,173,508	3,120
11	General	8,788	8,788	-	8,788	-
12	Subtotal	3,191,072	3,191,072	-	3,187,952	3,120
13	Common Utility Allocation	423,650	423,546	(104)	429,969	(6,423)
14	Total	3,614,722	3,614,618	(104)	3,617,921	(3,303)

Table 2-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors
- Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	0	0	0	0	0
2	Special Deposits and Working Funds	61	61	(0)	61	(0)
3	Other Receivables	28,977	28,969	(8)	28,978	(8)
4	Prepayments	3,671	3,671	0	3,671	0
5	Deferred Debits, Company-Wide	(203)	(203)	0	(203)	0
	Less					
6	Working Cash Capital not Supplied by Investors	2,179	2,179	(0)	2,179	0
7	Goods Delivered to Construction Sites	853	853	0	853	0
8	Accrued Vacation	39,184	38,849	(335)	37,199	1,650
	Add					
9	Prepayment, Departmental	1,955	1,955	0	1,955	0
10	Total Operational Cash Requirement	(7,756)	(7,428)	327	(5,770)	(1,658)
	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	64,537	63,810	(728)	43,716	20,094
12	Working Cash Capital Supplied by Investors	56,782	56,381	(400)	37,946	18,435

Table 2-10
2007 General Rate Case
Rate Base – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
WEIGHTED AVERAGE PLANT						
1	Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant - Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602
WORKING CAPITAL						
6	Material and Supplies - Fuel	0	0	0	0	0
7	Material and Supplies - Other	3,198	3,198	0	3,198	0
8	Working Cash	56,782	56,381	(400)	37,946	18,435
9	Total Working Capital	59,980	59,580	(400)	41,144	18,435
ADJUSTMENTS FOR TAX REFORM ACT						
10	Deferred Capitalized Interest	2,397	2,397	0	2,397	0
11	Deferred Vacation	3,809	3,809	0	3,809	0
12	Deferred CIAC Tax Effects	53,920	53,920	0	53,920	0
13	Total Adjustments	60,126	60,126	0	60,126	0
LESS DEDUCTIONS						
14	Customer Advances	29,485	29,485	0	29,485	0
15	Accumulated Deferred Taxes - Defense	0	0	0	0	0
16	Accumulated Deferred Taxes - Fixed Assets	301,416	301,291	(125)	301,334	(43)
17	Accumulated Deferred Taxes - Other	0	0	0	0	0
18	Deferred ITC	26,072	26,072	0	26,072	0
19	Deferred Tax - Other	0	0	0	0	0
20	Total Deductions	356,974	356,849	(125)	356,892	(43)
21	DEPRECIATION RESERVE	3,614,724	3,614,620	(104)	3,617,924	(3,303)
22	TOTAL RATE BASE	2,197,395	2,195,839	(1,556)	2,154,456	41,383

Table 2-11
2007 General Rate Case
Net TO Gross Multiplier – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue Base	1.000000	1.000000	0.000000	1.000000	0.000000
2	Less Interdepartmental Revenue	0.023700	0.023700	0.000000	0.023700	0.000000
3	Percent Revenue From Jurisdictional Customers	0.976300	0.976300	0.000000	0.976300	0.000000
4	Uncollectibles Percentage	0.002706	0.002525	(0.000182)	0.002521	0.000004
5	Franchise Requirements	0.009478	0.009480	0.000002	0.009480	(0.000000)
6	Total Uncollectibles and Franchise Requirements	0.012185	0.012005	(0.000180)	0.012001	0.000004
7	Net For State Income Taxes	0.987815	0.987995	0.000180	0.987999	(0.000004)
8	State Income Tax Percentage	0.088400	0.088400	0.000000	0.088400	0.000000
9	State Income Taxes	0.087323	0.087339	0.000016	0.087339	(0.000000)
10	Net For Federal Income Taxes	0.987815	0.987995	0.000180	0.987999	(0.000004)
11	Federal Income Tax Percentage	0.350000	0.350000	0.000000	0.350000	0.000000
12	Federal Income Taxes	0.345735	0.345798	0.000063	0.345800	(0.000001)
13	Net Operating Revenue	0.554757	0.554858	0.000101	0.554860	(0.000002)
14	Net To Gross Multiplier	1.802591	1.802263	(0.000328)	1.802256	0.000007

Table 3-1
2007 General Rate Case
Revenue Summary - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
<u>REVENUES AT PRESENT RATES</u>						
<u>CPUC Revenues (Retail)</u>						
1	Revenues from Sales	1,038,095	1,038,095	0	1,038,095	0
2	Plus: Non-Applicable Revenue	1,351	1,351	0	1,351	0
3	CPUC Revenue	1,039,446	1,039,446	0	1,039,446	0
4	Plus: Adopted Other Operating Revenue	8,159	8,159	0	8,159	0
5	Rate Case Revenue	1,047,605	1,047,605	0	1,047,605	0
<u>FERC Revenues (Wholesale)</u>						
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	(91)	91
8	FERC Revenue	0	0	0	(91)	91
9	Plus: Other Operating Revenue	0	0	0	91	(91)
10	Rate Case Revenue	0	0	0	0	0
11	Total Rate Case Revenue	1,047,605	1,047,605	0	1,047,605	0
<u>INCREASE IN RATE CASE REVENUE</u>						
12	CPUC Jurisdiction	17,790	(27,850)	(45,639)	(114,284)	86,434
13	FERC Jurisdiction	0	0	0	0	0
14	Total Increase	17,790	(27,850)	(45,639)	(114,284)	86,434
15	Percent	1.70%	(2.66%)		(10.91%)	
<u>INCREASE IN CPUC REVENUE FROM SALES</u>						
16	Amount	16,258	(29,811)	(46,069)	(115,453)	85,642
17	Percent	1.57%	(2.87%)		(11.12%)	
<u>REVENUES AT PROPOSED RATES</u>						
<u>CPUC Revenues (Retail)</u>						
18	Revenues from Sales	1,054,353	1,008,284	(46,069)	922,642	85,642
19	Plus: Non-Applicable Revenue	1,351	1,351	0	1,351	0
20	CPUC Revenue	1,055,704	1,009,635	(46,069)	923,993	85,642
21	Plus: Other Operating Revenue	9,690	10,120	430	9,328	792
22	Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434
<u>FERC Revenues (Wholesale)</u>						
23	Revenues from Sales	0	0	0	0	0
24	Plus: Non-Applicable Revenue	0	0	0	(91)	91
25	FERC Revenue	0	0	0	(91)	91
26	Plus: Other Operating Revenue	0	0	0	91	(91)
27	Rate Case Revenue	0	0	0	0	0
28	Total Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434

Table 3-2
2007 General Rate Case
Results of Operations – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
REVENUE						
1	Revenue at Effective Rates	1,064,044	1,018,404	(45,639)	932,061	86,343
2	Less Non-General Revenue	1,351	1,351	0	1,260	91
3	General Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434
OPERATING EXPENSES						
4	Energy Costs	0	0	0	0	0
5	Other Production	451,388	445,018	(6,370)	400,732	44,286
6	Storage	0	0	0	0	0
7	Transmission	5,603	5,603	0	5,603	0
8	Distribution	0	0	0	0	0
9	Customer Accounts	0	0	0	0	0
10	Uncollectibles	2,948	2,632	(316)	2,405	227
11	Customer Services	0	0	0	0	0
12	Administrative and General	190,877	182,449	(8,428)	165,339	17,110
13	Franchise Requirements	8,063	7,719	(344)	7,065	654
14	Amortization	6,476	6,476	0	6,476	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(179)	(179)	0	0	(179)
18	Subtotal Expenses	665,176	649,719	(15,458)	587,621	62,098
TAXES						
19	Superfund	0	0	0	0	0
20	Property	24,525	24,518	(7)	24,494	24
21	Payroll	21,654	21,485	(170)	19,759	1,726
22	Business	222	222	(0)	215	7
23	Other	62	62	(0)	60	2
24	State Corporation Franchise	14,398	12,298	(2,100)	11,146	1,152
25	Federal Income	54,535	46,245	(8,290)	39,958	6,287
26	Total Taxes	115,397	104,830	(10,567)	95,632	9,198
27	Depreciation	135,599	135,416	(183)	131,361	4,055
28	Fossil Decommissioning	(26,812)	(26,812)	0	(33,994)	7,182
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	889,360	863,153	(26,207)	780,619	82,533

Table 3-2
2007 General Rate Case
Results of Operations - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
31	Net for Return	176,035	156,603	(19,432)	152,702	3,901
32	Rate Base	2,002,989	1,781,886	(221,104)	1,737,502	44,384
	RATE OF RETURN					
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 3-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	1,065,395	1,019,755	(45,639)	933,321	86,434
2	O&M Expenses	665,176	649,719	(15,458)	587,621	62,098
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	46,464	46,287	(177)	44,529	1,758
6	Subtotal	353,754	323,749	(30,005)	301,172	22,578
DEDUCTIONS FROM TAXABLE INCOME						
7	Interest Charges	55,467	49,344	(6,123)	48,115	1,229
8	Fiscal/Calendar Adjustment	434	427	(7)	403	24
9	Operating Expense Adjustments	6,100	6,100	0	6,125	(25)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(775)	(775)	0	(775)	0
13	Capitalized Other	0	0	0	0	0
14	Subtotal Deductions	61,226	55,096	(6,130)	53,868	1,228
CCFT TAXES						
15	State Operating Expense Adjustment	1,217	1,217	0	1,217	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	158,605	158,160	(444)	151,949	6,211
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	2,280	2,280	0	2,163	117
20	Repair Allowance	0	0	0	0	0
21	Subtotal Deductions	223,328	216,754	(6,574)	209,197	7,556
22	Taxable Income for CCFT	130,426	106,996	(23,430)	91,975	15,021
23	CCFT	11,530	9,458	(2,071)	8,131	1,328
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	11,530	9,458	(2,071)	8,131	1,328
26	Defense Facilities Credit	1,660	1,660	0	1,660	0
27	Deferred Taxes - Interest	81	81	0	81	0
28	Deferred Taxes - Vacation	(69)	(69)	0	(69)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	1,196	1,167	(29)	1,342	(175)
31	Total CCFT	14,398	12,298	(2,100)	11,146	1,152

Table 3-3
2007 General Rate Case
Income Tax Summary - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	FEDERAL TAXES					
32	CCFT - Prior Year	14,702	14,724	22	15,291	(568)
33	Federal Operating Expense Adjustment	1,540	1,540	0	1,540	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	138,397	137,952	(445)	129,034	8,918
37	Federal Tax Depreciation - Other	0	0	0	0	0
38	Removal Costs	2,280	2,280	0	2,163	117
39	Repair Allowance	0	0	0	0	0
40	Preferred Dividend Credit	2,299	2,299	0	2,299	0
41	Subtotal Deductions	220,444	213,891	(6,552)	204,196	9,695
42	Taxable Income for FIT	133,310	109,858	(23,452)	96,976	12,882
43	Federal Income Tax	46,659	38,450	(8,208)	33,942	4,509
44	Defense Facilities Credit	5,992	5,992	0	5,992	0
45	Flowback of Excess Deferred Taxes	(2,788)	(2,788)	0	(2,788)	0
46	Deferred Taxes - Interest	413	413	0	413	0
47	Deferred Taxes - Vacation	(247)	(247)	0	(247)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	4,506	4,424	(82)	2,646	1,778
50	Total Federal Income Tax	54,535	46,245	(8,290)	39,958	6,287

Table 3-4
2007 General Rate Case
Expense Summary - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settltmt. +/- than PG&E	DRA	Settltmt. +/- than DRA
Expenses in 2004 Dollars						
1	Production (Generation)					
2	Labor	210,614	208,648	(1,966)	196,553	12,095
3	Materials and Services	205,672	201,726	(3,945)	172,717	29,009
4	Other	0	0	0	0	0
5	Total	416,286	410,375	(5,911)	369,270	41,104
6	Transmission					
7	Labor	2,966	2,966	0	2,966	0
8	Materials and Services	2,055	2,055	0	2,055	0
9	Other	134	134	0	134	0
10	Total	5,154	5,154	0	5,154	0
11	Distribution					
12	Labor	0	0	0	0	0
13	Materials and Services	0	0	0	0	0
14	Other	0	0	0	0	0
15	Total	0	0	0	0	0
16	Customer Accounts					
17	Labor	0	0	0	0	0
18	Materials and Services	0	0	0	0	0
19	Other	0	0	0	0	0
20	Total	0	0	0	0	0
21	Customer Service					
22	Labor	0	0	0	0	0
23	Materials and Services	0	0	0	0	0
24	Other	0	0	0	0	0
25	Total	0	0	0	0	0
26	Administrative and General					
27	Labor	37,300	37,300	0	29,404	7,896
28	Materials and Services	36,574	28,857	(7,717)	24,389	4,469
29	Other	68,565	68,565	0	68,547	18
30	Wage Related	7,441	7,441	0	7,441	0
31	Medical	33,126	33,126	0	29,605	3,521
32	Total	183,006	175,289	(7,717)	159,386	15,904

Table 3-4
2007 General Rate Case
Expense Summary - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Total Expenses in 2004					
33	Dollars					
34	Labor	250,880	248,914	(1,966)	228,924	19,990
35	Materials and Services	244,301	232,639	(11,662)	199,160	33,478
36	Other	68,698	68,698	0	68,680	18
37	Wage Related	7,441	7,441	0	7,441	0
38	Medical	33,126	33,126	0	29,605	3,521
39	Total	604,446	590,818	(13,628)	533,810	57,008
	Total Expenses in 2007					
40	Dollars					
41	Labor	276,127	273,963	(2,163)	251,961	22,002
42	Materials and Services	261,552	248,918	(12,634)	213,242	35,676
43	Other	68,698	68,698	0	68,680	18
44	Wage Related	8,186	8,186	0	8,186	0
45	Medical	33,126	33,126	0	29,605	3,521
46	Total	647,689	632,892	(14,798)	571,675	61,217

Table 3-5
2007 General Rate Case
Franchise Fees and Uncollectibles Expense - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	<u>Revenue</u>					
2	Rate Case Revenues	1,065,395	1,019,755	(45,639)	933,321	86,434
3	Percent Of Revenue From Customers	99.8200%	99.8200%	99.8200%	99.8200%	99.8200%
4	Rate Case Revenues From Customers	1,063,477	1,017,920	(45,557)	931,641	86,278
5	<u>Uncollectible Accounts</u>					
6	Uncollectible Rate	0.002772	0.002586	0.006928	0.002582	0.002629
7	Uncollectible Accounts Expense	2,948	2,632	(316)	2,405	227
8	<u>Franchise Fees</u>					
9	Rate Case Revenues From Customers	1,063,477	1,017,920	(45,557)	931,641	86,278
10	Uncollectible Accounts Expense	2,948	2,632	(316)	2,405	227
11	Net Rate Case Revenue From Customers	1,060,529	1,015,287	(45,242)	929,236	86,052
12	Franchise Rate	0.007603	0.007603	0.007603	0.007603	0.007603
13	Franchise Fees Expense	8,063	7,719	(344)	7,065	654

Table 3-6
2007 General Rate Case
Taxes Other than Income - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Property (Ad Valorem) Tax	24,525	24,518	(7)	24,494	24
2	Federal Insurance Contribution Act	18,793	18,646	(147)	17,149	1,497
3	Federal Unemployment Insurance	229	227	(2)	209	18
4	State Unemployment Insurance	1,174	1,165	(9)	1,071	94
5	San Francisco Payroll Tax	1,458	1,447	(11)	1,330	116
6	Total Payroll Taxes	21,654	21,485	(170)	19,759	1,726
7	Other Taxes	285	284	(1)	275	9
8	Total Taxes Other Than Income	46,464	46,287	(177)	44,529	1,758

Table 3-7
2007 General Rate Case
Plant In Service- Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	10,444,096	10,222,175	(221,921)	10,222,175	0
3	Common, General, and Intangible	518,857	518,857	0	518,857	0
4	Total 2004 End-of-Year Plant	10,962,952	10,741,031	(221,921)	10,741,031	0
5	2005 Full-Year Net Additions					
6	Functional	65,992	65,992	0	65,992	0
7	Common, General, and Intangible	3,800	3,800	0	3,795	5
8	Total 2005 Net Additions	69,792	69,792	0	69,787	5
9	2005 End-of-Year Plant					
10	Functional	10,510,088	10,288,167	(221,921)	10,288,167	0
11	Common, General, and Intangible	522,656	522,656	0	522,651	5
12	Total 2005 End-of-Year Plant	11,032,745	10,810,824	(221,921)	10,810,819	5
13	2006 Full-Year Net Additions					
14	Functional	(21,817)	(21,817)	0	(22,944)	1,126
15	Common, General, and Intangible	84,089	82,754	(1,335)	79,902	2,852
16	Total 2006 Net Additions	62,272	60,937	(1,335)	56,958	3,978
17	2006 End-of-Year Plant					
18	Functional	10,488,271	10,266,350	(221,921)	10,265,224	1,126
19	Common, General, and Intangible	606,746	605,410	(1,335)	602,553	2,857
20	Total 2006 End-of-Year Plant	11,095,017	10,871,760	(223,256)	10,867,777	3,983
21	2007 Full-Year Net Additions					
22	Functional	122,632	122,632	0	120,502	2,130
23	Common, General, and Intangible	72,404	72,404	0	45,399	27,005
24	Total 2007 Net Additions	195,036	195,036	0	165,901	29,135
25	2007 End-of-Year Plant					
26	Functional	10,610,903	10,388,982	(221,921)	10,385,726	3,256
27	Common, General, and Intangible	679,150	677,814	(1,335)	647,952	29,862
28	Total 2007 End-of-Year Plant	11,290,053	11,066,796	(223,256)	11,033,678	33,118

Table 3-7
2007 General Rate Case
Plant In Service- Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
29	2007 Weighted Average Net Additions					
30	Functional	50,115	50,115	(0)	48,784	1,331
31	Common, General, and Intangible	31,818	31,818	(0)	11,052	20,766
32	Total 2007 Weighted Average Net Additions	81,933	81,933	(0)	59,836	22,097
33	2007 Weighted Average Plant					
34	Functional	10,538,386	10,316,465	(221,921)	10,314,008	2,457
35	Common, General, and Intangible	638,564	637,228	(1,335)	613,606	23,623
36	Total 2007 Weighted Average Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080

Table 3-8
2007 General Rate Case
Depreciation – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
<u>Depreciation</u>						
1	Production	107,609	107,609	-	104,596	3,013
2	Transmission	3,467	3,374	(94)	3,467	(94)
3	Distribution	0	0	-	-	-
4	General	132	132	-	132	-
5	Subtotal	111,208	111,114	(94)	108,195	2,920
6	Common Utility Allocation	24,390	24,301	(89)	23,166	1,135
7	Total	135,599	135,416	(183)	131,361	4,055
<u>Depreciation Reserve</u>						
8	Production	8,535,561	8,535,561	-	8,532,868	2,693
9	Transmission	117,350	117,256	(94)	117,350	(94)
10	Distribution	0	0	-	-	-
11	General	(993)	(993)	-	(993)	-
12	Subtotal	8,651,918	8,651,825	(94)	8,649,225	2,600
13	Common Utility Allocation	176,933	176,788	(145)	192,385	(15,597)
14	Total	8,828,851	8,828,613	(238)	8,841,610	(12,997)
<u>Weighted Average Depreciation Reserve</u>						
8	Production	8,662,623	8,662,623	-	8,667,327	(4,703)
9	Transmission	115,616	115,569	(47)	115,616	(47)
10	Distribution	0	0	-	-	-
11	General	-2,733	-2,733	-	(2,733)	-
12	Subtotal	8,775,507	8,775,460	(47)	8,780,210	(4,750)
13	Common Utility Allocation	197,122	197,022	(100)	202,939	(5,917)
14	Total	8,972,629	8,972,482	(147)	8,983,149	(10,667)

Table 3-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors
Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	-	-	0	-	0
2	Special Deposits and Working Funds	58	58	(0)	58	0
3	Other Receivables	27,584	27,566	(18)	27,559	6
4	Prepayments	3,541	3,541	0	3,541	0
5	Deferred Debits, Company-Wide	(193)	(193)	0	(192)	(0)
	Less					
6	Working Cash Capital not Supplied by Investors	2,102	2,102	0	2,102	0
7	Goods Delivered to Construction Sites	823	823	0	823	0
8	Accrued Vacation	39,403	39,095	(309)	35,955	3,140
	Add					
9	Prepayment, Departmental	2,294	2,294	0	2,294	0
10	Total Operational Cash Requirement	(9,044)	(8,754)	290	(5,621)	(3,133)
	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses					
11		40,582	42,174	1,592	31,207	10,967
12	Working Cash Capital Supplied by Investors	31,538	33,420	1,883	25,587	7,833

Table 3-10
2007 General Rate Case
Rate Base - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
WEIGHTED AVERAGE PLANT						
1	Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant – Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080
WORKING CAPITAL						
6	Material and Supplies – Fuel	831	831	0	0	831
7	Material and Supplies – Other	65,586	65,586	0	65,586	0
8	Working Cash	31,538	33,420	1,883	25,587	7,833
9	Total Working Capital	97,954	99,837	1,883	91,173	8,664
ADJUSTMENTS FOR TAX REFORM ACT						
10	Deferred Capitalized Interest	(1,054)	(1,054)	0	(1,054)	0
11	Deferred Vacation	11,769	11,769	0	11,769	0
12	Deferred CIAC Tax Effects	0	0	0	0	0
13	Total Adjustments	10,715	10,715	0	10,715	0
LESS DEDUCTIONS						
14	Customer Advances	0	0	0	0	0
15	Accumulated Deferred Taxes – Defense	(42,088)	(42,088)	0	(42,088)	0
16	Accumulated Deferred Taxes – Fixed Assets	333,793	333,670	(123)	332,642	1,028
17	Accumulated Deferred Taxes – Other	0	0	0	0	0
18	Deferred ITC	2,320	2,320	0	2,320	0
19	Deferred Tax – Other	0	0	0	0	0
20	Total Deductions	294,025	293,902	(123)	292,874	1,028
21	DEPRECIATION RESERVE	8,988,606	8,988,459	(147)	8,999,126	(10,667)
22	TOTAL RATE BASE	2,002,989	1,781,886	(221,104)	1,737,502	44,384

Table 4-1
2007 General Rate Case
Net Capital Additions and Capital Additions - Test Year 2007
(Thousands of Dollars)

<u>Line No.</u>		<u>2007 Settlement</u>
	Net Capital Additions (Full Year Net Additions) ^{*See Note}	
1	Electric Distribution	696,932
2	Gas Distribution	207,743
3	Generation	195,036
4	Total Net Capital Additions	1,099,711
	Capital Expenditures	
5	Electric Distribution	862,006
6	Electric General and Intangible Plant	2,192
7	Total Electric Distribution	864,198
8	Gas Distribution	205,619
9	Gas General and Intangible Plant	1,080
10	Total Gas Distribution	206,699
11	Generation	182,185
12	Generation General and Intangible Plant	52,307
13	Total Generation	234,492
14	Common	342,359
15	Total Capital Expenditures	1,647,748

Commissioner Timothy Alan Simon, concurring on 40a:

In voting to approve today's decision, I applaud the Settlement Agreement between the Division of Ratepayer Advocates (DRA) and Pacific Gas & Electric Company (PG&E) et. al ¹. I recognize that it is the result of a dedicated effort and it will provide significant benefits to consumers.

Although not part of today's decision, I also want to note my support for the ratemaking treatment The Utility Reform Network (TURN) advocated regarding customer deposits. I believe it has considerable merit. In future general rate cases I intend to pay close attention to how the CPUC's ratemaking policy in this area may impact low-income customers.

In particular, while understanding that customers of higher rate paying risk are required to indemnify that risk because their credit rating and income, I do have serious concerns about this approved practice². This long held practice may be potentially predatory and arguably antiquated. As a regulatory body, we should avoid practices that penalize the poor and accordingly should review these approved practices with scrutiny. To the extent that customers are making a capital contribution through this deposit process, they should be treated on par with other sources of capital—including, but not limited to, the investment banking and commercial banking community.

However, I also believe this area of concern presents opportunities. For example, I encourage PG&E to look at this class of rate paying customers as potential participants in programs offering education and training in financial literacy and energy efficiency. This has the potential of being a mechanism that can help people come out of a cycle of poverty enabled by the practice of having to make a capital contribution as a condition precedent to receiving a necessity. Given the opportunities that modern financial technology provides, I encourage PG&E to seek innovative solutions to develop savings products for low income

¹ The Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, the Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Communities Association, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Association, Southern California Edison, The Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees. It is dated August 21, 2006.

² See, PG&E Electric Rule 7 - Deposits.

customers by collateralizing customer deposits and/or direct debits to savings accounts. With these opportunities in mind, I cite for example the Treasurer of San Francisco, Jose Cisneros, who has worked with financial institutions to create deposit products for low income customers to reduce dependency on predatory services like check cashing. I encourage PG&E to follow suit and turn this practice to benefit the customers they serve.

Finally, while recognizing that PG&E has already been engaged in the Commission's diversity efforts, I want to highlight my belief in the importance of PG&E's commitment to achieving greater diversity goals, as contained in an agreement in principle between the Greenlining Institute and PG&E. These goals include the area of Supplier Diversity, Management Diversity, and Philanthropy. In the Supplier Diversity area, PG&E has announced in its agreement with Greenlining a good faith attempt to meet the following goals:

- minority-contract goal of 20% by 2010 or earlier and
- aspirational goal of 27% minority contracts by 2015, if not better.

In connection with the area of customer deposits, I envision one area that PG&E could explore as the management of such deposits by minority-owned financial institutions. I see this agreement between The Greenling Institute and PG&E to be a critical step in improving diversity opportunities for minorities, women, and the disabled veterans entities.

/s/ TIMOTHY ALAN SIMON
TIMOTHY ALAN SIMON
Commissioner

San Francisco, California
March 15, 2007

STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket Nos. 6946 and 6988

Investigation into the existing rates of Central Vermont	)	
Public Service Corporation	)	Hearings at
	)	Montpelier, Vermont
and	)	<i>See Appendix A</i>
	)	
Tariff filing of Central Vermont Public Service	)	
Corporation requesting a 5.01% increase in its rates,	)	
effective August 29, 2004, for implementation as of	)	
April 1, 2005	)	

Order entered: 3/29/2005

PRESENT: Michael H. Dworkin, Board Chairman
David C. Coen, Board Member
John D. Burke, Board Member

APPEARANCES: Geoffrey Commons, Esq.
June Tierney, Esq.
for Vermont Department of Public Service

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for Central Vermont Public Service Corporation

James A. Dumont, Esq.
for AARP

Table of Contents

I. Introduction	4
II. Positions of the Parties and Concerns of the General Public	8
III. Earnings Cap	10
IV. Deferred Costs and Revenues	32
A. Deferred Accounts Included in Test-Year Rates	33
B. Deferred Accounts That Will Be Amortized Beginning in Rate Year 1	34
1. Regulatory Assets	34
2. Deferred Debits	35
3. Regulatory Liabilities	38
C. Deferred but Not Subject to Rate Recovery	43
D. Deferred for GAAP Purposes	44
V. Rate Base	56
A. Plant Adjustments	56
B. Accumulated Depreciation	69
C. Distributed Utility Planning Demand-Side Management	83
D. Distributed Utility Planning Account Correcting for Efficiency ("ACE")	87
VI. Cost of Service	90
A. Power Costs	90
B. Sale of Connecticut Valley Electric Company	101
C. Regulatory Commission Expense	111
D. Depreciation Expense	112
E. Payroll-Related Items	118
1. Number of Employees	118
2. Employee Incentive Plan	122
3. Officers' Compensation	127
4. Other Payroll Adjustments	129
5. Payroll Tax Expense	129
6. 401(k) Expense	131
F. Medical Insurance	132
G. Director and Officer Liability Insurance	135
H. Tree-Trimming	136
I. Cost Savings from Capital Additions	138
J. Revenues	140
1. Unbilled Revenues	140
2. Cable Television Pole Attachment Revenues	142
K. Agreed-Upon Adjustments	145

VII. Cost of Capital	146
VIII. Other Issues	159
A. Treatment of Regulated Affiliates	159
B. Customer Service Agreement	167
C. Rate Design	169
IX. Conclusion	170
X. Order	171
Appendix A: Hearing Schedule	175
Appendix B: Procedural History	176

I. INTRODUCTION

These proceedings examine the appropriate rate levels for Central Vermont Public Service Corporation ("CVPS" or "Company"), our state's largest electric utility, both for the last twelve months, and on a prospective basis. The Vermont Department of Public Service ("Department" or "DPS"), the agency responsible for representing the interests of the people of the state, asks us to reduce CVPS's rates by 6 percent, retroactive to April 7, 2004, and by 7.16 percent, effective April 1, 2005.¹ CVPS has presented evidence that it argues supports the need for a 0.3 percent rate increase during the period from April 7, 2004, through April 6, 2005, (although CVPS does not request that we modify its rates for this period) and a 2.9 percent increase commencing April 1, 2005. AARP has no specific recommendation on rates.

In today's Order, the Vermont Public Service Board ("Board") finds that CVPS does not have a revenue deficiency. Instead, we conclude that CVPS's present rates are higher than is just and reasonable, and must be reduced (although by considerably less than advocated by the Department). Accordingly, we direct that CVPS return to ratepayers the amount by which its rates were excessive (approximately 1.25 percent), for the period April 7, 2004, through April 6, 2005, and reduce its rates by approximately 1.88 percent (relative to the rate levels in existence today) commencing April 1, 2005.² For the past period, this will mean that CVPS must provide its customers with refunds of the difference between the rates we set and those now in effect.

The rate reductions we find just and reasonable today present a sharp contrast to the large rate increases occurring in other states in New England. Several factors contribute to the rate decreases. First, CVPS had substantial overearnings in 2001, 2002, and 2003, which, pursuant to CVPS's previous agreement, are returned to ratepayers starting in these cases. Second, in 2002, the Board approved the sale of the Vermont Yankee Nuclear Generating Station ("Vermont Yankee") to Entergy Nuclear Vermont Yankee. The terms of the sale had the effect of reducing CVPS's costs noticeably. Third, CVPS has been able to take advantage of higher market prices

1. The two periods overlap by six days. Thus, the rates that we review for the first period, although set on a full-year basis, will be displaced on April 1, 2005.

2. In this Order, we refer to the twelve months commencing April 1, 2004, as Rate Year 1 and the second twelve-month period as Rate Year 2. We will require CVPS to calculate the precise rate changes based upon the rulings in this Order and submit a compliance filing showing the results.

to sell excess power (including power saved due to energy efficiency measures) on favorable terms. Fourth, CVPS's capital costs have declined, largely because of lower interest rates, but also due to investors' perception that the sale of Vermont Yankee reduced risks. Finally, Vermont's decision not to pursue electric retail choice has allowed us to avoid some of the cost effects of higher wholesale market prices and the risk premium demanded by investors because of uncertainties about retail choice.

This proceeding is in fact two separate rate investigations — covering two sequential periods. The first case, Docket 6946, has its origins in the sale of Vermont Yankee, of which CVPS owned 35 percent, and an associated Power Purchase Agreement.³ At the time we approved the sale of Vermont Yankee in 2002, we were concerned that the benefits of the sale might not flow through to ratepayers. We found that, in addition to the proceeds of the sale, one benefit of the sale would be the reduced power costs from Vermont Yankee beginning in 2004. This was due to the fact that the prices in the Power Purchase Agreement were below the cost of that power if CVPS had retained ownership. Our Order, therefore, directed CVPS and Green Mountain Power Corporation ("GMP") to file cost-of-service studies in April 2003.⁴

After the filing of those studies, CVPS and the Department entered into a settlement agreement which we reviewed in Docket 6866. On January 27, 2004, we approved the settlement, but only if CVPS and the Department affirmatively agreed to a series of conditions. CVPS asked us to reconsider that decision, stating that without changes, CVPS did not believe it could reasonably accept the conditions. Prior to our ruling on reconsideration, the Department filed a letter stating that a further modification of the settlement agreement would not be feasible or appropriate and asking us to immediately open this investigation. Accordingly, on April 7, 2004, we opened Docket 6946 pursuant to 30 V.S.A. § 227(b). The rates we now establish in Docket 6946 cover the twelve months ending March 31, 2005, and will be retroactive to April 1, 2004, the start of that investigation. On July 15, 2004, CVPS filed a proposal to increase rates by

3. Docket 6545, Order of 6/13/02 at 13.

4. Docket 6545, Order of 6/13/02 at 135–136.

5.01 percent; we opened Docket 6988 to consider that proposed rate increase.⁵ Our decision in that docket will apply prospectively, taking effect on April 1, 2005.

This Order addresses both proceedings. As noted, we find that CVPS must reduce its rates in both Rate Year 1 and Rate Year 2. There are many individual rulings, described below, that explain the differences between CVPS's position and what we find just and reasonable after consideration of the evidence. The largest single issue, however, relates not to costs that CVPS incurred in Rate Year 1 or will incur in Rate Year 2, but rather to accounting for CVPS's overearnings during 2001, 2002, and 2003. In 2001, CVPS and the Department had agreed to a Memorandum of Understanding resolving two CVPS rate increase requests. As part of that agreement, CVPS agreed that it would book for future return to ratepayers all earnings in excess of an 11 percent return on equity. CVPS booked some excess earnings in 2002 and 2003. The Department contests the calculation methodology CVPS employed and asserts that CVPS had overearnings in all three years — with a total more than \$14 million in excess of CVPS's calculation (before adding carrying costs). We find here that the Department's proposal is consistent with our approval of the MOU and is reasonable. Due to the magnitude of the recalculation of overearnings, we will allow CVPS to amortize the return to ratepayers over four years.

CVPS also raised a broad challenge to the Department's approach to these proceedings, arguing that a significant portion of the Department's proposed cost-of-service reductions are not based upon the application of traditional ratemaking policies. CVPS characterizes the Department position as advocating a "new regulatory paradigm" which "creates substantial uncertainty as to the predictability of the Vermont ratemaking system."⁶ Our review of the record does not lead us to the same conclusion. The number and extent of these new proposals is much less than the Company's claim of a "new regulatory paradigm" would suggest, although the Department has advocated some adjustments that it had not previously recommended. Most of the Department's proposals are consistent with positions it has advocated for many years in many

5. During the course of this proceeding, CVPS has reduced the amount of the rate increase that it seeks, so that the request is now for an increase of 2.9 percent. See CVPS Reply Brief at 14.

6. CVPS Brief at 3.

cases involving Vermont utilities. CVPS's assertion that they represent changes may stem from the fact that this is the first fully litigated rate case for CVPS in more than 10 years.⁷

For the adjustments that the Department had not sought in prior cases, we have evaluated each of these on its own merits, applying the regulatory principles that we typically use. For reasons that we explain below, we have not adopted some of these proposals, not because they are new, but because the adjustments are inconsistent with our fundamental ratemaking standards. We have accepted other "new" adjustments, based upon our conclusion that, based on the evidence and the law, the change was necessary to produce just and reasonable rates. This is consistent with basic principles of administrative law that we may need to modify past rulings when necessary to set just and reasonable rates — a policy routinely followed by American courts and commissions and which we explained in detail in a CVPS rate proceeding nearly 18 years ago.⁸

Moreover, we find that in numerous instances, such as proposed plant additions, it is CVPS (rather than the Department) that seeks changes to the standards we have previously enunciated. Indeed, CVPS made arguments here concerning the application of the known and measurable standard to plant additions that we rejected in CVPS's last fully-litigated rate cases in 1994. Similarly, CVPS sought to update its filing even though we ruled in the 1994 cases that such updates were impermissible.

We have also considered the Company's financial stability. In fact, our rulings reflect the fundamental financial health of the Company in recent years, and clear record evidence that such health is likely to continue.

Finally, today's Order addresses the concerns we expressed in our January 27, 2004, Order in Docket 6866 that CVPS has a large amount of deferred costs. CVPS will begin amortizing these costs April 1, 2004, so that by early 2007, the deferrals will have been fully

7. We issued our final order in the last fully litigated cases, Dockets 5701/5724, on October 31, 1994. Since that time, CVPS has had other rate increase requests, which were either settled or closed. Tr. 1/11/05 at 86 (Frankiewicz). See, e.g., Dockets 6120/6460, Order of 6/26/01; Dockets 6018/6120, Order of 3/2/01; Docket 5863, Order of 4/30/96.

8. *Tariff Filing of Central Vermont Public Service Corporation*, Docket 5132, Order of 7/31/87 at 31–35.

recovered. Even with these amortizations, we find that a small rate decrease is appropriate in both rate years.

II. POSITIONS OF THE PARTIES AND CONCERNS OF THE GENERAL PUBLIC

This section describes the parties' overall rate recommendations. The parties' positions on individual issues are discussed in the sections of this Order related to those issues.

Central Vermont Public Service Corporation

CVPS argues that a rate reduction for Rate Year 1 is not justified because it has an alleged revenue deficiency of \$0.881 million, or 0.3 percent. CVPS originally filed for an increase of 5.0 percent in rates, and now asserts that the record supports a rate increase of \$7.655 million, or 2.9 percent, in Rate Year 2. These positions take into account the Company's agreement with the DPS on power cost issues,⁹ and the reduction of regulatory asset amortizations by application of the \$3.8 million in deferred 2004 earnings.¹⁰ CVPS argues that its return on equity should be 11.0 percent.

Vermont Department of Public Service

The DPS argues that the Board should reduce CVPS's rates for Rate Year 1 by 6 percent, and order refunds in the amount of \$15.818 million. The DPS asserts that the Board should reduce CVPS's rates for Rate Year 2 by 7.16 percent (a reduction of \$18.858 million from CVPS's claimed cost of service). However, the DPS states that these amounts should be adjusted to reflect its power cost agreement with CVPS, its revised recommendation regarding incentive compensation,¹¹ and perhaps for the disallowance of unsupported plant costs.¹² The DPS argues that CVPS's return on equity should be 8.75 percent.

9. The agreement between CVPS and the DPS regarding power cost issues is addressed in Section VI.A, below.

10. CVPS's deferral of \$3.8 million in 2004 earnings is described on page 108, below.

11. The DPS's revised recommendation on incentive compensation is discussed in Section VI.E.2, below.

12. The DPS's recommendation regarding plant costs is discussed in Section V.A, below.

AARP

AARP did not provide a specific cost-of-service calculation for either rate year. Instead, AARP supports the recommendations of the DPS, except that AARP recommends a return on equity of 10.0 percent, an amortization period of 6 years for deferred debits, and that no costs associated with, or resulting from, the sale of Connecticut Valley Electric Company be charged to ratepayers.

Members of the General Public

In addition to hearing from formal parties in Dockets 6946 and 6988, we held a public hearing in both dockets on September 14, 2004, at eight locations in or close to CVPS's service territory via the Vermont Interactive Television Network. The purpose of the public hearing was to gather information from, and the opinions of, the public at large.¹³ Three members of the public spoke in support of a rate decrease for Rate Year 1, or against a rate increase in Rate Year 2. For example, one citizen stated in response to a recent bill insert he received from CVPS (which stated that absent a rate inquiry initiated by the Board, and the threat of a rate decrease, CVPS would not have sought an increase):

The disingenuousness of this position is beyond belief or comprehension. CV has stated in so many words that there is no actual need for a rate increase at this time. I don't know whether this is intended as leverage against a decrease or an attempt to shift blame for higher electrical rates in the public's eye to the Board. It is, however, a statement by CVPS that there is no immediate need for an increase, and I for one do not wish to be burdened with an elective rate increase . . .¹⁴

No members of the public at the public hearing opposed a rate decrease for Rate Year 1, nor did any support a rate increase in Rate Year 2. The Board also received some letters from the general public, largely in opposition to CVPS's requested rate increase for Rate Year 2.

13. Under Vermont law, our decision must be based upon the evidence presented by formal parties during the evidentiary hearings. However, Title 30 also provides for public (non-evidentiary) hearings; public comments play an important role by raising new issues or offering perspectives that we should consider.

14. Tr. 9/14/05 at 12-13 (French).

III. EARNINGS CAP

Dockets 6120 and 6460 were investigations into rate increases requested by CVPS. On June 26, 2001, the Board issued an order in those dockets approving a Memorandum of Understanding between CVPS and the DPS ("2001 MOU"). This settlement agreement recommended a rate increase for CVPS, and required ratepayers to pay rates that provided for full recovery of the costs of CVPS's purchases of power from Hydro-Québec pursuant to the contract between Hydro-Québec and the Vermont Joint Owners, despite CVPS's imprudent decision to commit to that contract and the fact that the power was not economically used and useful. In other words, pursuant to the 2001 MOU, CVPS was allowed to recover costs from ratepayers that would not have been allowed if the Board had based its decision in those cases on traditional cost-of-service methodologies.¹⁵ The 2001 MOU also provided ratepayers with several benefits including, among others, CVPS's write-down of \$9 million in regulatory assets, and a cap on CVPS's earnings in 2001, 2002, and 2003.¹⁶

The specific language in the 2001 MOU regarding this earnings cap is at the heart of one of the key issues in the proceedings before us today. The MOU does not specify an exact calculation methodology for implementing the earnings cap provisions of the 2001 MOU. CVPS and the DPS have proposed significantly different calculation methodologies. The different calculation methodologies lead to very different amounts of overearnings in 2001, 2002, and 2003. According to CVPS, using its recommended methodology, the Company's total overearnings over the three-year period the earnings cap was in effect were \$3,156,050;¹⁷ CVPS has proposed to return this amount, plus carrying costs, to ratepayers in the instant proceedings. According to the DPS, using its recommended methodology, CVPS's total overearnings over the three-year period the earnings cap was in effect were \$17,385,000;¹⁸ the DPS argues that, in these proceedings, we should order the return of this amount, plus carrying costs, to ratepayers. The difference between the two amounts is \$14,228,950.

15. Dockets 6120/6460, Order of 6/26/05 at 4–5.

16. Dockets 6120/6460, Order of 6/26/05 at 3.

17. Gibson reb. pf. 11/19/04 at 5.

18. Schultz sup. pf. at 4.

Findings

1. Paragraph 29 of the 2001 MOU states: "The Company's allowed rate of return on common equity shall be 11.00%." Dockets 6120/6460, Order of 6/26/01 at appendices page xxi.

2. Paragraph 30 of the 2001 MOU states:

To the extent that CVPS's calendar year earned return on equity on its Vermont jurisdictional electricity utility operations in 2001 exceeds 11.0%, the dollar amount of such excess shall be applied (a) to reduce regulatory asset accounts as specified by the DPS and approved by the Board at the time of any such excess, or (b) as otherwise agreed by CVPS and the DPS. Any such dollar amount of excess in 2002 and 2003 over CVPS's allowed return on equity in effect in such calendar year also shall be credited as provided herein, unless a superseding approved agreement or order on rates shall have earlier become effective.

Dockets 6120/6460, Order of 6/26/01 at appendices page xxi.

3. CVPS has recorded the following amounts as regulatory liabilities associated with the 2001 MOU's earnings cap:

- 2001 — \$0
- 2002 — \$680,874
- 2003 — \$2,475,176

Gibson reb. pf. 11/19/04 at 5.

4. CVPS received an accounting order from the Board dated April 4, 2003, authorizing the Company to defer the \$680,874 in 2002 overearnings shown in finding 3, above. This accounting order included the following paragraph:

3. This Order is limited to the accounting treatment for the subject dollar amount and does not bar any party from contesting or the Board from determining or modifying the subject dollar amount, in whole or in part, in any rate proceeding in which the subject dollar amount is reflected in cost of service.

Accounting Order of April 4, 2003.

5. CVPS's proposed calculation methodology starts with the Company's consolidated net income and common stock equity. It then reduces both items by the net income and common stock equity of its non-regulated subsidiaries and its New Hampshire utility subsidiary. The resulting net income is compared to the resulting common stock equity to arrive at the return on

equity for CVPS's Vermont jurisdictional electric utility operations. Schultz and DeRonne pf. at 33.

6. The DPS's proposed calculation methodology calculates the revenue requirement for the year of determination using actual information in the same format and manner that is routinely used for setting rates. The only adjustments to actual amounts are for standard accepted regulatory adjustments or adjustments to remove costs that are not to be included in regulatory cost of service. Schultz and DeRonne pf. at 33–34.

7. Using the DPS's proposed calculation methodology results in significantly higher overearnings than using CVPS's proposed calculation methodology. Specifically, the DPS's proposed calculation methodology results in overearnings of:

- 2001 — \$4,607,000
- 2002 — \$6,115,000
- 2003 — \$6,663,000

Schultz sup. pf. at 4.

8. Using the DPS's calculation methodology does not always result in higher overearnings than using CVPS's calculation methodology. The result is company-specific. For example, when the DPS applied its methodology to GMP in 2004, the DPS's calculation methodology resulted in underearnings, while a methodology similar to that proposed by CVPS resulted in overearnings. Tr. 1/13/05 at 16–18 (Schultz).

9. Two factors that can lead to differences in the results of the two proposed methodologies are: (1) below-the-line expenses and revenues; and (2) the amount of cash and temporary investments. Tr. 1/13/05 at 17–18 (Schultz).

10. CVPS had significant temporary cash investments during 2001, 2002, and 2003. The value of these temporary cash investments was:

- \$38,885,892 as of January 1, 2001;
- \$32,929,809 as of January 1, 2002;
- \$21,190,246 as of January 1, 2003;
- \$41,300,087 as of December 31, 2003.

Exh. CVPS-11 at 110; exh. CVPS-12 at 110; exh. CVPS-13 at 110.

11. CVPS's calculation included an 11 percent return on equity on the Company's temporary cash investments. These amounts are not being used to provide service to Vermont ratepayers; therefore, ratepayers should not be providing an 11 percent return on these investments. Tr. 11/4/04 at 94–95 (Schultz).

12. CVPS's calculation method included an 11 percent return on items that are normally excluded from ratemaking. For example, account 426 is always excluded for ratemaking purposes.¹⁹ In 2001, that account included the \$9 million write-off of deferred accounts that was committed to by CVPS in the 2001 MOU. CVPS's method would allow the Company to earn a return on this write-off. Schultz and DeRonne reb. pf. at 31; tr. 11/4/04 at 95 (Schultz).

13. The DPS's calculation method is based on the methodology used in setting rates.²⁰ Schultz sup. pf. at 5.

14. The purpose of an overearnings calculation is to reflect how the actual period results compare to the actual revenues that were collected. Actual results should not be replaced with estimates, even for those items for which the Board traditionally uses multi-year averages when setting rates. Schultz sup. pf. at 2.

15. If the Board orders CVPS to use a different methodology to recalculate its overearnings for 2001, 2002, and 2003, CVPS will not be required to restate its earnings for those years. Tr. 1/12/05 at 159 (Gibson).

Discussion

The dispute between the DPS and CVPS related to the 2001 MOU's earnings cap centers on Paragraphs 29 and 30 of the 2001 MOU. The issue before the Board is, given the language of the 2001 MOU, what overearnings calculation methodology should be used to calculate CVPS's overearnings in 2001, 2002, and 2003. The DPS recommends that we calculate CVPS's overearnings in the same way that we establish rates. CVPS recommends that we calculate its

19. Account 426 is composed of expenses that are not to be included in a cost-of-service filing. Tr. 1/12/05 at 17 (Gibson).

20. However, in a few specific instances, as noted in the discussion below, we find the DPS's methodology to be different from the cost-of-service methodology that we typically apply when setting rates. We have not accepted those specific elements in the DPS's methodology.

overearnings using information from its required filings with the Securities and Exchange Commission.

We have carefully reviewed the specific language of the 2001 MOU and the Board's Order approving it, and considered all the arguments made by the parties. We conclude that the DPS's cost-of-service-based calculation methodology should be used, and we require CVPS to use this methodology to recalculate its overearnings for 2001, 2002, and 2003, as part of its compliance filing in these proceedings. However, as explained in more detail below, when CVPS recalculates its overearnings, it should:

- remove 100 percent of transmission revenues before applying the wholesale allocation factor;
- include the portion of Construction Work In Progress on which it does not accrue an allowance for funds used during construction;
- treat all of its regulated affiliates above-the-line; and
- reflect our decisions in this Order regarding Distributed Utility Planning Demand-Side Management, and the 2002 Vermont Yankee Mid-Cycle Outage.²¹

This decision is a direct application of the terms of the 2001 MOU and the Board Order approving it, and is not a modification of either one. Paragraph 30 of the 2001 MOU requires CVPS to return its 2001, 2002, and 2003 overearnings to ratepayers; our decision today implements that paragraph. As discussed further below, the earnings cap provisions in the 2001 MOU use the language of traditional ratemaking practice. After reviewing this language, we conclude that the 2001 MOU does not specify an exact methodology for calculating CVPS's overearnings, but that the methodology for calculating overearnings must be consistent with traditional ratemaking practice.

One of the fundamental principles of traditional ratemaking is that ratepayers should not be required to pay for, or provide a return on, investments that do not serve them. The DPS's methodology is consistent with this principle, while CVPS's equity-based methodology is not.²² CVPS's methodology would require ratepayers to provide a return on items that are traditionally

21. These decisions increase CVPS's expenses in 2001, 2002, and 2003, and decrease CVPS's deferral accounts.

22. The DPS's proposal does not result in unjust and unreasonable rates that would deny CVPS a reasonable opportunity to recover its allowed return, in violation of 30 V.S.A. § 218, as CVPS contends. Rather, it provides CVPS a reasonable opportunity to recover its allowed return on investments that serve ratepayers.

excluded from rates, including millions of dollars of unused cash and the \$9 million writeoff that CVPS agreed to make as part of the 2001 MOU.²³ If we were to require ratepayers to provide a return on such items, we would be denying ratepayers one of the benefits they received from the 2001 MOU — the assurance that CVPS would return to ratepayers any earnings above its allowed return on equity. We consider that benefit to be particularly significant because other provisions of the 2001 MOU resulted in ratepayers paying for costs that would not have been included in rates if the Board had set CVPS's rates using traditional cost-of-service methodologies.²⁴

Our conclusion is that under the terms of the 2001 MOU CVPS must calculate its overearnings using a method that is consistent with traditional ratemaking practice. This is also consistent with the testimony of the Company's Chief Financial Officer at the time the Board was considering whether to approve the 2001 MOU. Mr. Boyle testified that the 2001 MOU "would not require that customers pay rates that are in excess of what should be due under cost of service ratemaking doctrines."²⁵ CVPS asserts that this testimony was provided in the context of arguing against the imposition of a protection against unjust enrichment, not in the context of the methodology for calculating overearnings.²⁶ However, Mr. Boyle's point that the MOU was adequate protection clearly rests on the comparison to traditional ratemaking. We accept this "traditional ratemaking" characterization of the 2001 MOU, and conclude that the 2001 MOU earnings cap provisions should be applied in a manner that ensures that ratepayers do not pay more during the 2001–2003 time period than they would have under cost-of-service ratemaking.

23. See, findings 11 and 12, above. CVPS argues that its rates are subject to a presumption of reasonableness, and that the DPS has not provided evidence or a compelling basis to overcome this presumption with respect to the implementation of the earnings cap. We disagree; the DPS has shown that CVPS's methodology would reduce overearnings by requiring ratepayers to pay a return on items that do not provide service to them. That would be unreasonable.

In addition, the DPS's proposed calculation methodology would not cause CVPS to write off \$9 million twice, as CVPS asserts. Rather, the DPS's proposed methodology would ensure that ratepayers are not required to pay a return on the single \$9 million writeoff that CVPS agreed to make.

24. Adoption of the DPS's recommendation would not deny CVPS benefits it received under the 2001 MOU, as CVPS argues. The Company still has the opportunity to earn an 11 percent return on investments that serve ratepayers, and CVPS is in a financially stronger and more stable position today than it was when the 2001 MOU was signed. See, findings 283 and 292, below, for more information regarding CVPS's improved financial situation.

25. Tr. 1/12/05 at 24 (Gibson).

26. CVPS Reply Brief at 141–142.

The DPS's recommended cost-of-service-based methodology would ensure this, while CVPS's proposed equity-based methodology would not.

Thus, we conclude that the language of the 2001 MOU and our Order approving that agreement require us to accept the DPS's proposed calculation methodology. However, we do understand that CVPS may have had some reason to believe that its recommended methodology is consistent with prior Board practice.²⁷ The last time the Company was subject to an earnings cap,²⁸ the Board accepted the results of an overearnings calculation methodology substantially similar to the one the Company has proposed using in the instant proceedings.²⁹ The DPS challenged CVPS's calculation methodology in the 1994 proceedings, arguing that the calculation of earnings should be consistent with ratemaking,³⁰ but the Board rejected the DPS's proposed adjustment because of an evidentiary failure.³¹ Even though the Board did not rule on the merits of either CVPS's or the DPS's methodology in the 1994 proceedings,³² given the Board's decision in those cases, we do not find it unreasonable for CVPS to have thought its calculation methodology might be acceptable to the Board in its current proposed application.

In recognition of this situation, we have decided it is appropriate to extend the period over which CVPS will return its 2001–2003 overearnings to ratepayers. CVPS had originally proposed a three-year amortization period. We conclude that a four-year amortization period is more appropriate. This will reduce the immediate impact on the Company's earnings and cash

27. CVPS Reply Brief at 141.

28. CVPS was subject to an earnings cap in 1993 as the result of a settlement agreement that it entered into with the DPS in Docket 5651. The earnings cap provision from that settlement agreement stated:

2(c). Central Vermont agrees to an effective Return on Equity ("ROE") applicable to its Vermont retail business to 12.0% and to credit to accrued [Demand-Side Management] costs any and all amounts earned in excess of that 12.0% ROE during 1993.

Exh. CVPS-43 at 2.

29. The sole difference is that the last time, CVPS included its CV Realty subsidiary in its calculation while in the instant dockets, the same subsidiary is excluded. Exh. CVPS-44 at 5–6 (Henkes pf. 5/27/94, pages numbered 33–34). CV Realty is CVPS's smallest subsidiary, with a 13-month average common equity investment of \$283,869, and net income of \$2,938 in 2003. Exh. CVPS-JHG-18 at 4.

30. Exh. CVPS-48 at 5 (Henkes sur. pf. 8/5/94, page numbered 19).

31. Dockets 5701/5724, Order of 10/31/94 at 91.

32. In fact, the Board expressly held the issue open by stating that it would not make the DPS's proposed adjustment "at this time." Dockets 5701/5724, Order of 10/31/94 at 91.

flow, while at the same time, ensuring that ratepayers will ultimately recover all the funds owed to them.

Appropriate Calculation Methodology

To decide upon an appropriate calculation methodology, we start with an analysis of the 2001 MOU and the Board's Order approving it. We conclude that the DPS's proposal, rather than CVPS's is appropriate, based on two related, fundamental considerations:

- (1) the meaning of the 2001 MOU's language; and
- (2) consistency with traditional ratemaking practice.

We address each of these considerations below.

Language of the 2001 MOU

Both CVPS and the DPS point to several key phrases in Paragraphs 29 and 30 of the 2001 MOU that they argue support their interpretations. The cited phrases include "allowed return on equity," "Vermont jurisdictional electricity utility operations," and "return on common equity." All of these phrases are commonly used in traditional ratemaking practice and form part of the basis for our conclusion that the language of the 2001 MOU requires us to approve an overearnings calculation methodology that is consistent with traditional ratemaking principles.

For example, the phrase "allowed return on equity" is very commonly used when setting rates. Each time the Board sets rates, it must decide the affected company's allowed return on equity.³³ In the context of the 2001 MOU, we find that the term indicates, as the DPS asserts, that the calculation must separate items on which the Company does not have an allowed return from those on which it does (in other words, separate those items serving ratepayers from those that do not).

Similarly, the concept behind "Vermont jurisdictional electricity utility operations" underlies much of our traditional ratemaking practice. When we set rates, we determine what costs are within our jurisdiction, and what costs are appropriately part of a company's utility

33. As noted below, the Board uses the terms allowed return on equity and allowed return on common equity interchangeably.

operations, and therefore recoverable from ratepayers. In the context of the 2001 MOU, we conclude that "Vermont jurisdictional electricity utility operations" do not include items that are normally excluded from ratemaking. Such items are generally excluded for one of three reasons:

- (1) they are not within the Board's jurisdiction (for example, costs incurred by CVPS's unregulated subsidiaries); or
- (2) they are within the Board's jurisdiction, but are not being used to serve ratepayers (for example, unused cash); or
- (3) they are within the Board's jurisdiction, but are not appropriate for recovery from ratepayers (for example, imprudently-incurred costs).

If something is not within the Board's jurisdiction, it is, by definition, not part of "Vermont jurisdictional electricity utility operations." And, it is consistent with the purpose of the earnings cap provision of the 2001 MOU (to return to ratepayers any earnings above CVPS's allowed return on equity) for items that are not being used to serve ratepayers or are otherwise not appropriate for recovery from ratepayers to be excluded from "Vermont jurisdictional electricity utility operations"; stated another way, it would be illogical to interpret the earnings cap provision as requiring ratepayers to provide a return on items for which it is inappropriate for them to pay.

CVPS asserts that "return on common equity" is not commonly used in Vermont in the context of a cost-of-service analysis; the Company argues the phrase "return on equity" or "ROE" is typically used instead.³⁴ This assertion is incorrect. Contrary to CVPS's arguments, "return on common equity" is a phrase that is often used in traditional ratemaking practice in Vermont. The Board has consistently used "return on common equity" and "return on equity" interchangeably in

34. CVPS cites *Petition of Green Mountain Power Corporation re Increased Rates*, 131 Vt. 284 (1973) in support of its position, arguing that this case shows that the Vermont Supreme Court distinguishes between "return on equity" and "return on common equity." In this decision, the Vermont Supreme Court refers often to GMP's "return on equity" and the phrase "common equity" is used only in two tables regarding CVPS's capital structure. However, the rate shown for GMP's common equity in the capital structure tables is the same as the rate later referred to by the Court as GMP's "return on equity." See the charts on page 295, and the text on pages 298–300. Thus, while this case is an example of the Vermont Supreme Court using the term "return on equity" in a cost-of-service context, the case provides no indication that the Vermont Supreme Court considers the two terms to be different. On the contrary, it appears to indicate that the terms can be used interchangeably.

the context of cost-of-service analyses across industries during the last 15 years.³⁵ In fact, to be precise, when we set a return on equity, we actually mean return on common equity, since that is the only class of stock for which we set a return. We do not, for example, set a return on preferred stock, even though that is also equity. Even the 2001 MOU, itself, uses the two terms interchangeably — Paragraph 29 quantifies CVPS's "allowed rate of return on common equity" while Paragraph 30 refers to an "allowed return on equity." If the two terms were not synonymous, it would not be possible to give meaning to the last sentence of Paragraph 30, since CVPS's "allowed return on equity" is not quantified anywhere in the 2001 MOU; only CVPS's "allowed rate of return on common equity" is quantified in Paragraph 29. Thus, we conclude that the use of the term "return on common equity" instead of "return on equity" in Paragraph 29 of the 2001 MOU does not support CVPS's argument that a cost-of-service-based methodology for calculating overearnings would be inconsistent with the 2001 MOU.³⁶

We do agree with CVPS that "common equity" is not the same as "rate base," but that is not the relevant distinction. The paragraph of the 2001 MOU that defines the earnings cap refers to CVPS's "return on equity on its Vermont jurisdictional electricity utility operations," not to its return on common equity. The key distinction is that CVPS includes millions of dollars of unused cash that was not serving ratepayers in the Company's common equity; however, this cash was not part of the Company's Vermont jurisdictional electricity operations.³⁷

Finally, we are not persuaded by CVPS's argument that the 2001 MOU's linkage of "earnings" to "operations," instead of to "rate base" or "utility property," supports its proposed

35. See, e.g., Docket Nos. 5841/5859, Order of 6/16/97 at 78, 300–306 ("return on common equity" used for setting the rate, "return on equity" used in discussion of a penalty that reduced the previously determined rate); Docket Nos. 5700/5702, Order of 10/5/94 at 78–82 ("return on equity" and "return on common equity" used interchangeably); Docket No. 5532, Order of 4/2/92 at 84 (uses "cost of equity" and "return on common equity" interchangeably); Docket No. 5491, Order of 9/27/91 at 3, 4 (uses both "return on equity" and "return on common equity").

Significantly, in Docket 5651, the earnings cap agreed to by CVPS referred solely to "return on equity." It was this earnings cap that the Board reviewed in Dockets 5701/5724, in which the Board accepted CVPS's overearnings calculation. The Company's present argument that its proposed methodology is integrally linked to the phrase "return on common equity" is inconsistent with that previous ruling.

36. In addition, if there were a distinction between the two terms, it would be significant that Paragraph 30 of the 2001 MOU, which describes the earnings cap, uses "return on equity," not "return on common equity."

37. Tr. 11/4/04 at 95 (Schultz).

calculation methodology. The fact that the 2001 MOU links earning to "operations" rather than to "rate base" or "utility property" is a distinction without a difference. As explained above, we find that "Vermont jurisdictional electricity utility operations" are made up only of items normally included in ratemaking. These are the same items that are included in rate base.

Consistency with Traditional Ratemaking Practice

Now that we have concluded that the language of the 2001 MOU requires that we approve a methodology that is consistent with traditional ratemaking practice, the next step is to consider which of the two methodologies presented in these proceedings is consistent with those practices.

Traditionally, utility rates in Vermont are based on a company's cost to provide utility services (including a return on its prudent investments that are used to provide service to ratepayers). The standard practice is for a utility to prepare a cost-of-service filing that is based on a historic test year, adjusted for known and measurable changes. This cost-of-service filing includes information on the utility's revenues, costs, rate base, and cost of capital. This filing is then reviewed, and further adjustments may be made to it. Ultimately, in a fully-litigated rate case, the utility's rates are based upon the final, adjusted cost-of-service and rate base information.³⁸

The DPS's cost-of-service-based methodology is generally similar to the methodology the Board uses to set rates. It starts with a cost of service, except that the cost of service shows actual results for the particular year in question, rather than information from a historic test year that is adjusted for known and measurable changes. In general, items are included or excluded from the earnings cap calculation based on whether they are included or excluded in a traditional cost-of-service calculation that would be used to set rates.

38. CVPS argues that because the 2001 MOU was a bottom-line settlement with no approved cost of service or rate base, it is reasonable to conclude that the methodology for calculating overearnings would not require the development of a cost of service and rate base for each year that the earnings cap was in effect. CVPS Reply Brief at 140. We disagree. Many bottom-line settlements approved by the Board do not include approved costs of service and rate bases. The fact that the 2001 MOU followed this general rule does not indicate anything regarding the parties' expectations with respect to the methodology for calculating overearnings, and most certainly does not indicate that the calculation of overearnings should ignore established ratemaking principles.

CVPS's methodology, on the other hand, is radically different from the methodology the Board uses to set rates. This equity-based methodology uses information from filings with the Securities and Exchange Commission regarding consolidated net income and common stock equity, adjusted to remove the portions of both items attributable to its non-regulated subsidiaries and Connecticut Valley Electric Corporation.³⁹ Other than that one adjustment, CVPS's methodology does not distinguish between items that are traditionally included or excluded from a company's cost of service. As a result, CVPS's methodology requires ratepayers to provide a return on the Company's millions of dollars of unused cash and other items that are not traditionally allowed in rates (such as the \$9 million write-off that CVPS agreed to as part of the 2001 MOU). This is inappropriate. As the DPS's earnings cap witness pointed out, including unused cash in common equity can distort the results of an earnings cap calculation. Cash is theoretically generating its own return, and is not providing service to ratepayers.⁴⁰ This issue is particularly important in CVPS's case because of the size of the Company's unused cash balances which averaged approximately \$36 million in 2001, \$27 million in 2002, and \$31 million in 2003.

Thus, we conclude that the DPS's proposed calculation methodology is generally consistent with the requirements of the 2001 MOU and traditional ratemaking practice. Accordingly, we find this methodology to be appropriate to use to calculate CVPS's overearnings in 2001, 2002, and 2003.

Having determined that, there are four issues regarding the details of the DPS's calculation methodology that relate to the consistency of the DPS's proposal with traditional

39. For seven decades, rate-regulated companies that trade public stock have routinely kept separate sets of accounts for SEC, tax, and rate-regulation purposes. Reconciliation of the three should be feasible whenever accuracy must be checked; but, since each set of accounts is kept for a different purpose, it is necessary and proper to distinguish between rate-regulation accounts and reports to the SEC. Indeed, without that distinction, rate review would have no meaning since all results would already be resolved by prior SEC filings. See, e.g., J. Bonbright et al., *Principles of Public Utility Rates*, (PUR 1988) at 287; and J. Suelflow, *Public Utility Accounting: Theory and Application*, (MSU Press 1973) at 18–20 and at 40: "a regulatory body cannot be bound in its interpretation of results by a prescribed system of accounts."

40. Tr. 1/13/05 at 17–18 (Schultz).

ratemaking practices.⁴¹ These are: (1) "averaging" adjustments; (2) transmission revenues; (3) construction work in progress ("CWIP"); and (4) treatment of regulated affiliates. Our decision rule with respect to all of these issues is that the starting point for the overearnings calculation in each year should be a traditional cost-of-service calculation, except that actual costs and revenues should be used to the extent possible. The only adjustments to these actual amounts should be for standard accepted regulatory adjustments or adjustments to remove costs that are not to be included in a regulatory cost of service.

Using this decision rule, we conclude that no adjustment to actual expenses should be made for those items for which the Board traditionally allows average expense levels in cost-of-service filings. Such "averaging" adjustments are appropriate to use when setting rates, but do not function as intended when calculating overearnings.⁴²

With respect to transmission revenues, in its cost-of-service filings in these proceedings, CVPS followed the historical practice of removing 100 percent of its transmission revenues before applying the wholesale allocation factor.⁴³ The DPS did not challenge this adjustment to CVPS's costs of service for ratemaking purposes.⁴⁴ CVPS argues that the same practice should be followed in the overearnings calculation.⁴⁵ The DPS, on the other hand, asserts that the transmission revenues should not be removed before applying the wholesale allocation factor. Instead, the DPS argues that the wholesale allocation factor should be applied to both revenues and expenses.⁴⁶ We are not persuaded by the DPS's argument. The DPS asserts that its recommended approach is "more equitable,"⁴⁷ but the DPS has not explained why the traditional

41. In addition, we note that CVPS and the DPS each pointed out some minor errors in the other party's overearnings calculations. After the errors were pointed out, the opposing party admitted that they should be corrected. Since these minor errors are no longer contested, we do not address them further. We do, however, expect that the overearnings calculations performed by CVPS as part of their required compliance filing will reflect the agreed-upon corrections.

42. Gibson reb. pf. 11/19/04 at 11.

43. Frankiewicz pf. at 18; exh. CJF-1; exh. CJF-5.

44. Exh. DPS-L&A-11 at schedule 1; exh. DPS-L&A-12 at schedule 1. The only adjustment to Other Operating Revenues that the DPS has proposed is related to cable television pole attachment revenue. Exh. DPS-L&A-11 at schedule 20; exh. DPS-L&A-12 at schedule 20.

45. Gibson reb. pf. 11/19/04 at 10.

46. Schultz sup. pf. at 2–3.

47. Schultz sup. pf. at 3.

practice is sufficiently equitable in a cost-of-service calculation for ratemaking purposes, but not in an overearnings calculation.⁴⁸ Therefore, CVPS should remove 100 percent of transmission revenues before applying the wholesale allocation factor when calculating its overearnings for 2001, 2002, and 2003.

The issue of CWIP is similar to that of transmission revenues. The portion of CWIP on which a company does not accrue an allowance for funds used during construction is traditionally included in a company's rate base. CVPS argues that it should also be included in its overearnings calculation.⁴⁹ The DPS, on the other hand, asserts that because there is no evidence that CWIP is providing service to customers, CWIP should not be included in CVPS's rate base in the overearnings calculation. As in the case of transmission revenues, we conclude that the DPS has not shown why the traditional practice is appropriate in a cost-of-service calculation for ratemaking purposes, but not in an overearnings calculation. Therefore, when calculating its overearnings for 2001, 2002, and 2003, CVPS should include the portion of CWIP on which it does not accrue an allowance for funds used during construction.

Our basic decision rule leads us to conclude that CVPS's regulated affiliates should be treated above-the-line in the calculation of its overearnings. As explained in Section VIII.A, below, we determine that CVPS should account for its regulated affiliates above-the-line in its cost-of-service filings in these proceedings. We considered whether there was some justification for treating the regulated affiliates differently in an overearnings calculation than in a cost-of-service used to set rates, and conclude that there is not. Removing the regulated affiliates from the cost-of-service calculation would not be a standard regulatory adjustment, nor would it remove costs that should be excluded from a cost-of-service. We are not persuaded by the DPS's argument that the regulated affiliates should be treated above-the-line in the overearnings calculations only to the extent that the regulated affiliates were included in the revenue

48. We clarify that our decision should not be interpreted as a ruling on whether the traditional practice regarding transmission revenues is appropriate in a cost-of-service proceeding. That issue has not been raised in these proceedings, and we do not address it. Rather, our decision is limited to the question of whether transmission revenues should be treated differently in an overearnings calculation than in a cost-of-service filing for the purpose of setting rates. We conclude that they should not.

49. Tr. 1/12/05 at 124–125 (Gibson).

requirement filing which led to the 2001 MOU.⁵⁰ That revenue requirement filing resulted in a bottom-line settlement that did not specify how the regulated affiliates were treated. In the instant proceedings, CVPS states that it treated all its regulated affiliates except for Vermont Yankee below-the-line in its filing that led to the 2001 MOU,⁵¹ but we do not conclude that this is sufficient basis for making a distinction among regulated affiliates. Instead we find that since CVPS's affiliates should be treated above-the-line in its cost-of-service filings for ratemaking purposes, they should also be treated above-the-line for calculations of overearnings.

Retroactive Ratemaking

CVPS asserts that if the Board were to accept the DPS's proposed calculation methodology and require the Company to recalculate its overearnings for 2001, 2002, and 2003, we would be engaging in prohibited retroactive ratemaking. We conclude that CVPS's arguments about retroactive ratemaking are misplaced. The 2001 MOU and our Order approving it set rates prospectively (from 2001 forward), with a requirement that earnings over 11 percent be returned to ratepayers. Our decision today is not retroactively changing CVPS's rates because the rates were set in 2001 by the 2001 MOU and the Board's June 26, 2001, Order approving that agreement.

As the Vermont Supreme Court stated:

Retroactive ratemaking occurs when rates are set at a level that permits a utility to recover past losses, or that requires it to refund past excess profits, that resulted from a disparity between projected expenses of a prior rate base and actual incurred expenses. *In re Central Vermont Pub. Serv. Corp.*, 144 Vt. 46, 52, 473 A.2d 1155, 1158 (1984). While "the Board may consider a utility's recent past operating experience with such adjustments as will make the test period reflect typical conditions in the immediate future," it may not set a rate "that requires a utility to refund to consumers a portion of its previously earned profits." *Id.* at 53, 56. "[T]he Board has no statutory authority to make whole either the utility company or its customers for inequities that existed in the past." *Id.* at 53.⁵²

50. Letter from Geoffrey Commons, Esq., DPS, to Susan M. Hudson, Clerk, Board, dated February 2, 2005, at 2.

51. CVPS Reply Brief at 236.

52. *In re Green Mountain Power Corp.*, 162 Vt. 378, 387–388 (1994). In this Order, all references to *In re GMP* are to this decision, unless otherwise specified.

The Vermont Supreme Court has consistently held that retroactive ratemaking is prohibited, whether the intent was to make utilities whole for costs not contemplated in a previous rate order (as in *In re CVPS*, *supra*) or to return excess utility profits to ratepayers (as in *In re GMP*, *supra*).⁵³

However, none of the cases identified by CVPS involve the application of a Board-approved settlement agreement, and CVPS has failed to explain how those cases apply to a situation where the utility has previously agreed, and the Board has previously ordered it, to return its excess earnings to ratepayers. Indeed, in the 2001 MOU, CVPS agreed, in return for valuable consideration, to return its excess earnings to ratepayers, and the Board issued an order approving the 2001 MOU. CVPS itself recognizes its obligation to return overearnings, notwithstanding the general prohibition on retroactive ratemaking. The Company reflected the return of its overearnings (calculated using its methodology) in its original cost-of-service filings in these proceedings. The disagreement in the instant proceedings relates to the calculation of overearnings under the 2001 MOU⁵⁴ — should CVPS be allowed to use a calculation methodology that results in the Company earning a return from ratepayers on items expressly excluded from legitimate "utility profits" (as that term is used in the CVPS and GMP appellate cases)? We conclude that CVPS should not be allowed to do so, and that requiring CVPS to recalculate its overearnings accordingly does not constitute retroactive ratemaking as defined by the Vermont Supreme Court. To read the 2001 MOU as CVPS now suggests is to argue, in essence, that the Company never intended to do what it promised to do.

CVPS tries to characterize its argument regarding retroactive ratemaking in many different ways. It alleges that:

53. We note, however, that 30 V.S.A. § 227(b) provides a specific exception to the Vermont Supreme Court's prohibition against retroactive ratemaking that is relevant to Docket 6946. Pursuant to 30 V.S.A. § 227(b), when the Board opens an investigation into a utility company's rates, and issues its decision within seven months, the decision is retroactive to the day the Board opened the investigation. In Docket 6946, CVPS waived the seven-month statutory deadline, and agreed that as long as the Board issued its decision by March 29, 2005, the decision would still be retroactive to the day the Board opened the investigation.

54. CVPS asserts that if the MOU is a contract, there is no ambiguity in its wording. CVPS further argues that if there is ambiguity, then the rule of uniform practical construction supports CVPS because the DPS did not object to CVPS's performance of the agreement. We explain later in this section of our Order why we do not find CVPS's arguments regarding the timing of the DPS's challenge to be persuasive. That same rationale applies here.

- (1) the DPS is asking the Board to alter the terms of a prior Board order;⁵⁵
- (2) an earnings cap based on a cost-of-service methodology automatically constitutes retroactive ratemaking;⁵⁶ and
- (3) requiring CVPS to recalculate its overearnings using the DPS's proposed methodology is the same as requiring the Company to correct an "error" (as defined in *Maine Public Advocate v. Public Utilities Commission*, 476 A.2d 178 (Me. 1984)).⁵⁷

We address each of these in turn.

First, we conclude that the DPS is not seeking to alter the terms of a prior Board order. Rather, the DPS is seeking to enforce the terms of a prior Board order. CVPS argues that the 2001 MOU requires the use of CVPS's overearnings calculation methodology. We disagree. Instead, as we concluded above, the 2001 MOU does not specify an exact calculation methodology, but does specifically refer to "allowed" earnings and repeatedly relies upon phrases consistent with the DPS's "traditional ratemaking" rationale. Therefore, it is necessary for us to determine what the appropriate calculation methodology is. That requires us to apply the 2001 MOU and our Order approving it; it does not require us to modify either of those documents.⁵⁸

Second, we find that an earnings cap based on a cost-of-service methodology does not constitute retroactive ratemaking. As we explained above, our decision today simply applies the terms of the 2001 MOU and our Order approving it. That 2001 Board Order set rates prospectively (from 2001 forward); those previously-established rates, with their required refunds of overearnings, still control. Nothing in our decision today changes the rates established in 2001. All we are doing is applying those rates, which include the terms of the 2001 MOU that require CVPS to return its overearnings during 2001–2003.

Third, CVPS relies on *In re Maine Public Advocate* which holds that "errors made in the calculation of a utility's base rates may be remedied only prospectively."⁵⁹ We conclude that

55. CVPS Brief at 85.

56. CVPS Reply Brief at 145–146.

57. CVPS Reply Brief at 146–147.

58. Since we are not modifying the 2001 MOU or our order approving it, CVPS's arguments regarding *In re Burlington Electric Department*, 151 Vt. 543 (1989), do not apply. (That case involved a modification to a prior Board order without proper notice and hearing.)

59. *In re Maine Public Advocate*, *supra* at 183.

requiring CVPS to recalculate its overearnings is not the same as requiring a utility to fix an error in the calculation of the utility's base rates. The methodology used to calculate CVPS's overearnings is unrelated to the calculation of CVPS's previous base rates. There was no error made in the calculation of CVPS's previous base rates. Those rates were established as part of the bottom-line settlement that is the 2001 MOU. As a result, there are no specific calculations of CVPS's previous rates that could be reconsidered, and the decision in *In re Maine Public Advocate* is not relevant to the issue before us.

Timing of Challenges to CVPS's Proposed Calculation Methodology

One of CVPS's arguments against the adoption of the DPS's proposed calculation methodology is that if the DPS or the Board disagreed with CVPS's proposed calculation methodology, it should have challenged it earlier, well before the instant proceedings.⁶⁰ CVPS claims that the 2001 MOU required resolution of issues concerning the determination of earnings cap amounts "at the time of any such excess."⁶¹ We do not accept that interpretation of the 2001 MOU. Nevertheless, today's Order has the same substantive effect as if the excess earnings had been determined shortly after the end of 2001, 2002, and 2003.

CVPS argues that various times would have been appropriate for the DPS and/or the Board to challenge CVPS's proposed calculation methodology including: (1) when the Company reported its 2001 earnings;⁶² (2) any time after early 2002 when CVPS provided its financial statements, including its earnings amounts, to the DPS;⁶³ (3) at the time CVPS filed its request for an accounting order that would enable it to defer the amount it calculated as its 2002

60. CVPS also challenges the timing of the DPS's proposal within the current case. The Company asserts that adoption of the DPS's proposal would be unfair because it wasn't made clear until three days before rebuttal hearings. We find that this contention is not supported by the record in these proceedings. While it is true that the DPS's last testimony on its recommended calculation methodology was filed three days before rebuttal hearings, the DPS first challenged CVPS's calculation methodology and described its proposed alternative in its direct testimony that was filed on October 1, 2004. In addition, as the DPS points out, its proposed methodology is consistent with the policy that the DPS recommended in Dockets 5701/5724, nearly 10 years ago.

61. CVPS Reply Brief at 130, quoting Paragraph 30 of the 2001 MOU.

62. CVPS Reply Brief at 148.

63. CVPS Reply Brief at 150–151.

overearnings;⁶⁴ and (4) in CVPS's cost of service filed in Docket 6545 or in Docket 6866, the ensuing investigation into the settlement agreement between the DPS and CVPS.⁶⁵ CVPS asserts that by not challenging CVPS's calculation methodology earlier, the DPS "accepted or acquiesced in the Company's method of calculation."⁶⁶

We are not persuaded by CVPS's arguments. While the DPS could have challenged CVPS's earnings cap calculation methodology at any of the times identified, the 2001 MOU did not require it to do so. If it was important to CVPS that the amount of overearnings be finally determined before it closed its financial books for the year in question, CVPS could have petitioned the Board to make such a determination. CVPS did not do so.

CVPS states in its reply brief that "A determination by the Board at this late date which changes the calculation of the recorded excess earnings amounts raises serious financial concerns for the Company and its stakeholders."⁶⁷ CVPS also contends more broadly that adoption of the DPS's recommendation threatens CVPS's financial stability. We are not persuaded by these assertions. First, CVPS's total shareholder return has been near, or at, the top of all publicly-traded electric and combination utilities in 2001, 2002, and 2003.⁶⁸ That is an indication of a financially healthy company, not one that is financially unstable. We do understand that restatement of earnings for prior years can affect a company's financial health; however, CVPS's Chief Financial Officer testified that if the Board required CVPS to recalculate its overearnings, the Company would *not* be required to restate its earnings for 2001, 2002, and 2003.⁶⁹ Thus, CVPS has failed to demonstrate that any "serious financial concerns" will result from a recalculation of its overearnings using the DPS's methodology.

CVPS requested that the Board issue an accounting order, which was expressly limited to the accounting treatment of the amount of overearnings identified by CVPS. As stated in finding

64. CVPS Brief at 85. CVPS also argues that by the time CVPS filed its request for an accounting order related to 2002 overearnings, the Board could no longer require CVPS to recalculate its 2001 overearnings because CVPS's calculation was a "mistake" and such mistakes can't be corrected in a retroactive fashion. CVPS Reply Brief at 146–147.

65. CVPS Brief at 63–64.

66. CVPS Reply Brief at 139.

67. CVPS Reply Brief at 130.

68. Exh. Board-1; tr. 11/2/04 at 83 (Gamble).

69. See, finding 15, above.

4, above, the accounting order also explicitly provided that any party may contest, and the Board may modify, the identified dollar amount in any rate proceeding in which the identified dollar amount is reflected in the cost of service. Thus, the accounting order explicitly deferred a ruling on whether CVPS calculated the amount of the overearnings correctly until a future rate proceeding.⁷⁰

CVPS asserts that the Board's accounting order allowed the DPS to challenge, in the future, CVPS's calculation of the deferred amount, but not the methodology used by CVPS to determine the amount to be deferred.⁷¹ There is simply nothing in the Board's April 4, 2003, accounting order to support such a distinction. On the contrary, the accounting order clearly stated that CVPS's calculation could be reviewed in future rate proceedings.⁷² Not only is it eminently reasonable to conclude that the calculation methodology is part of the calculation, but also the accounting order expressly provides that the order is limited to the accounting treatment of the excess earnings. CVPS's calculation methodology is clearly outside the scope of the "accounting treatment" that was the subject of the Board's limited approval.

We are troubled that, once again, CVPS appears to be asserting that, even though the Board's accounting order expressly stated that the Board could modify the overearnings deferral amount in any rate proceeding in which the amount is included in the cost of service, it is, in effect, too late for the Board to do so. This is the latest example of a disturbing situation — the Board issues an accounting order that states it is limited to the accounting treatment of a particular amount, only to later have the company argue that the accounting order resolved more than just the accounting treatment. As we stated in Docket 5983 (a rate case involving Green Mountain Power Corporation):

Under 30 V.S.A. § 221, the Board is authorized to issue accounting orders; notice and opportunity for hearing are not necessarily required. We must stress that, in the absence of full notice and opportunity for hearing on a request for an accounting order, such an order will not have final effect in a

70. The instant proceedings are CVPS's first rate proceedings since the accounting order was issued.

71. CVPS Brief at 54.

72. See, finding 4, above.

later rate proceeding under 30 V.S.A. §§ 225-227, and it would be wrong for any party to think otherwise.⁷³

Comparison with Treatment of GMP

CVPS asserts that the DPS is proposing to treat the Company much more harshly than it did GMP.⁷⁴ CVPS notes that, pursuant to two different settlement agreements approved by the Board in two different dockets, GMP has been subject to an earnings cap since 2001.⁷⁵ However, the DPS has not challenged GMP's overearnings calculations for 2001 and 2002, although it has examined GMP's calculation methodology for 2003. CVPS alleges that challenging CVPS's earnings cap calculations back to 2001, while only challenging GMP's back to 2003, constitutes "disparate treatment."⁷⁶

The DPS argues that the DPS-GMP settlement agreements are explicitly non-precedential, as are virtually all settlement agreements filed with the Board, because each company's circumstances are different, particularly with respect to an earnings cap. However, the DPS points out that it did require GMP to recalculate its 2003 earnings using the same methodology that the DPS is recommending in the instant proceedings.⁷⁷

We disagree with the Company's argument that it is unfair for the DPS to challenge CVPS's overearnings calculations for 2001 and 2002 when it did not challenge GMP's overearnings calculations for the same time periods. Far more significant is that the same policy is being applied to all utilities in a comparable situation at the same time. The DPS did not challenge either GMP's or CVPS's overearnings calculations in Dockets 6866 and 6867, which were contemporaneous. But, in 2004, the DPS challenged both utilities' overearnings calculations. The fact that the relevant calculation for GMP extended only back through 2003, while the relevant calculation for CVPS extended back through 2001, does not mean that the DPS is treating CVPS more harshly than it is GMP. Rather, it is simply a reflection of the fact

73. Docket 5983, Order of 6/8/98 at 20.

74. CVPS Brief at 69–72.

75. Docket 6107, Order of 1/23/01 at 121 (order paragraph 6); Docket 6867, Order of 12/22/03 at 43 (order paragraph 8).

76. CVPS Brief at 72.

77. DPS Reply Brief at 11.

that GMP's and CVPS's situations are different. Docket 6866 led to a final resolution of issues for GMP, including the establishment of new rates, while, as described in Section I, above, Docket 6867 did not lead to a final resolution of issues for CVPS. As a result, the instant proceedings are the appropriate place to consider CVPS's overearnings calculations pursuant to the Docket 2001 MOU, which includes the years 2001, 2002, and 2003.

CVPS's Other Arguments

CVPS makes two additional arguments in support of its position regarding the overearnings calculation methodology; as explained below, we do not find either of these arguments persuasive.

CVPS argues that a new ruling on the method for determining compliance with earnings caps is not warranted in order to take account of an intervening change in the applicable legal context or otherwise to avoid inequitable administration of the laws. This argument is unavailing because we have not based our determination on either a change in law or to avoid the inequitable administration of the law.

Finally, CVPS argues that if the Board wants to change the earnings cap calculation methodology, it should do so in a proceeding with all stakeholders, with any changes applied prospectively. CVPS makes the same assertion with respect to a change in accumulated depreciation policy. We explain why we reject this argument in our discussion of that issue in Section V.B, below.

Decisions on Other Issues That Affect the Overearnings Calculation

Two of our other decisions in this Order have an impact on CVPS's overearnings in 2001, 2002, and 2003. As discussed in Section V.C below, CVPS incorrectly deferred Distributed Utility Planning Demand-Side Management costs that should have been expensed, and there are additional funds that were previously collected from ratepayers for that purpose that should be returned to ratepayers now. CVPS should treat these Distributed Utility Planning Demand-Side Management costs as expenses in the years in which they should have been recorded (the funds to be returned to ratepayers should be treated as a reduction to the cost of service in 2003) for

purposes of performing the overearnings calculation. As discussed in Section VI.A below, we are reducing the amount of CVPS's deferred costs as a result of the 2002 Vermont Yankee Mid-Cycle Outage by \$403,000. CVPS should include this \$403,000 in its 2002 expenses when performing the overearnings calculation.

IV. DEFERRED COSTS AND REVENUES

Findings

16. CVPS has deferred recognizing certain revenues and expenses in accordance with accounting orders and other orders issued by the Board. Gibson pf. at 36–37; exhs. CVPS-JHG-13 at 2, CVPS-JHG-14, CVPS-JHG-15, and CVPS-JHG-16.

17. CVPS has relatively high balances in deferred debits and regulatory assets, which distort the Company's actual financial position and ratemaking accuracy. *Id.*; tr. 1/12/05 at 13–14 (Gibson).

18. The deferred costs include: Distributed Utility Planning Demand-Side Management costs; Distributed Utility Planning Account Correcting for Efficiency costs; Docket No. 6270 Independent Power Production ("IPP") costs; Docket No. 6330 Retail Choice costs; Vermont Yankee Fuel Rod Repair costs; Vermont Yankee Incremental Power costs due to the sale of Vermont Yankee; and Incremental Decommissioning costs for the Yankee Atomic Electric Power Company ("Yankee Atomic") the Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and the Maine Yankee Atomic Power Company ("Maine Yankee"). The deferred revenues include various deferred credits as partial offsets to the deferred costs described above. Gibson pf. at 36–37; Schultz and DeRonne pf. at 23–24; exh. CVPS-4A; exh. CVPS-JHG-13.

19. CVPS's original cost-of-service filing for Rate Year 1 included amortization of these deferred costs and revenues. CVPS's original cost-of-service filing for Rate Year 2 did not reflect the effects of beginning the amortization of these deferred costs and revenues in Rate Year 1. Schultz and DeRonne pf. at 23–24.

20. Rate Year 1 amortizations can be recorded on the Company's books during Rate Year 1. Tr. 1/11/05 at 69 (Frankiewicz).

21. If amortization is reflected on the books of account in Rate Year 1, the amount recognized should not be included in deferral accounts in subsequent years. *Id.* at 62–63.

22. A three-year amortization period for most deferred expenses is reasonable. Talbot/Roschelle pf. at 26; Gibson pf. at 37.

23. In a rate case, regulatory assets, deferred charges, and regulatory liabilities that the Board finds reasonable are included in the cost of service that the Board establishes for setting rates. When the amortization of these amounts is complete, the amounts remain "in rates." This could lead to charges being over-recovered or under-recovered in rates, when the amortization for particular costs and revenues ends. Behrns pf. at 16–19.

24. If, at the conclusion of an amortization cycle, the yearly amortization amount associated with a regulatory asset or deferred debit is booked as a regulatory liability, there will be no over-recovery of costs to the Company. The converse is true if completed regulatory liabilities are booked as regulatory assets. *Id.*

A. Deferred Accounts Included in Test-Year Rates

25. CVPS's current rates include the amortization and recovery of several regulatory assets. These are Connecticut Yankee Dismantling, Maine Yankee Dismantling, SFAS 109 Deferred Taxes, and 2002 Millstone Refueling. There is no dispute regarding the continued amortization of these accounts. The balance and expense for each account that is currently being recovered in rates are summarized in the table below:

	Balance 12/31/03	Recorded to Expense in Test Year	Carrying Charges
<u>Regulatory Assets</u>			
Connecticut Yankee Dismantling	\$ 2,979,858	\$ 794,364	No
Maine Yankee Dismantling	7,287,060	1,038,190	No
SFAS 109 Deferred Taxes ⁷⁸	5,639,760	209,468	No
2002 Millstone Refueling	109,087	654,524	No
<u>Regulatory Liabilities</u>			
Vermont Yankee Recapture	393,939	48,732	No
Total (Net)	\$ 15,621,826	\$ 2,647,814	

Exh. CVPS-JHG-13.

B. Deferred Accounts That Will Be Amortized Beginning in Rate Year 1

1. Regulatory Assets

Docket 5980 Distributed Utility Planning Demand-Side Management and
Docket 5980 Distributed Utility Planning Account Correcting for Efficiency

26. Findings 136–145, below, are incorporated by reference.

Docket 6270 VEPPI Cost Mitigation/Docket 6330 Retail Choice

27. On January 29, 2000, the Board issued two accounting orders to CVPS related to:
 (1) Docket No. 6270 (Rule 4.100) costs; and (2) the Docket No. 6330 Retail Choice Petition and
 DPS Electric Utility Industry Restructuring Bill-Backs. Gibson pf. at 38 –39.

28. In accordance with these two accounting orders, the Company deferred and continues to
 defer: (1) its costs incurred to pursue the mitigation of the power costs incurred by the Vermont
 Electric Power Producers, Inc. ("VEPPI"), the Board's Rule 4.100 Purchasing Agent, that was the
 subject of Docket 6270; and (2) the costs incurred by the Company or billed-back to it by the

78. Of the \$209,468 amortized, \$58,229 is allocated to Accumulated Deferred Income Tax Liability, and the remainder (\$151,239) is allocated to the Income Statement (though not all allocated amounts affect Vermont retail rates). Exh. CVPS JHG-13 at Attachment PSB 1-1B.

DPS relating to the effort to implement a voluntary restructuring program in CVPS's service territory that was the subject of Docket 6330. Gibson pf. at 38 –39.

2. Deferred Debits

Vermont Yankee Fuel Rod Repair

29. In 2002, Vermont Yankee experienced an unscheduled outage to resolve defects affecting certain of the plant's in-core fuel rods (referred to as the 2002 "Mid-Cycle Outage"). Vermont Yankee determined that individual fuel rods had developed small leaks that released radioactivity into the core. Vermont Yankee decided that the best course of action was to shut down and fix the problem. Page pf. at 4.

30. The 2002 Mid-Cycle Outage lasted approximately 12 days. During this time, Vermont Yankee remedied the problem. Page pf. at 5.

31. CVPS incurred replacement power costs for energy and costs to secure options to purchase energy at a fixed cost. Vermont Yankee also incurred incremental operation and maintenance costs that it passed on to its sponsors, including CVPS. Page pf. at 6.

32. Vermont Yankee offset part of the costs through a credit arising from a vendor warrantee for the defective fuel. Page pf. at 7.

33. On July 18, 2002, the Board issued an accounting order that authorized CVPS to defer the costs associated with the defective fuel rods at Vermont Yankee. Gibson pf. at 39; Schultz and DeRonne pf. at 27.

34. In Docket 6460, power costs were based upon an expected forced outage rate for Vermont Yankee of 4 percent. The actual production in 2002 was significantly above the target assumed by the forced outage rates (after factoring out the period of the Mid-Cycle Outage, the costs of which CVPS has deferred). Lamont pf. at 7.

35. The value of the power production in excess of the 4 percent forced outage rate is \$403,000. CVPS's proposed deferral account should be reduced by this \$403,000.⁷⁹ Lamont reb. pf. at 5; tr. 2/18/05 at 74–75 (Schultz, Watts).

79. See Section VI.A for the discussion of this adjustment.

Vermont Yankee Incremental Costs Due to Sale

36. As part of the Docket No. 6545 Order of June 13, 2002, approving the sale of Vermont Yankee, the Board issued two accounting orders for CVPS. Pursuant to the first such order, CVPS was authorized to defer any incremental income tax expense recorded under Statement of Financial Accounting Standards No. 109 as a result of its receipt of the cash proceeds resulting from the sale of Vermont Yankee and commencement of the related transaction agreements. Pursuant to the second accounting order, CVPS was permitted to defer incremental costs (excluding incremental income tax expenses covered under the first accounting order arising as a result of the receipt of the cash proceeds) that occur in 2002 after the sale of Vermont Yankee and consummation of the related transaction agreements. Gibson pf. at 39; exh. CVPS-JHG-15 at 2; see Docket 6545, Order of 6/13/02 at 141–144.

37. The Company deferred its applicable Vermont Yankee sale incremental costs. These costs represent the difference between the costs that the Company would have incurred had it not pursued the sale and those it incurred by pursuing the sale. This difference is primarily related to the Company's need to reflect the deferral and amortization of refueling maintenance costs for Vermont Yankee. Page pf. at 13.

38. Rate Year 1 rate base balance for the Vermont Yankee sale incremental costs should be \$5,954,406, and Rate Year 1 amortization should be \$1,984,802. Exh. DPS-L&A-11, at page 1 of schedule SR15, and at page 7 of schedule 8.

Vermont Yankee — June 04 Fire Outage

39. In mid-2004, Vermont Yankee experienced an unscheduled outage due to a busbar fault and subsequent transformer fire. As a result, CVPS incurred additional replacement power costs during this time period of \$835,946.⁸⁰ Watts pf. at 12–13; Page reb. pf. at 13–14.

40. CVPS may be able to recover some or all of these costs through the Ratepayer Protection Plan that Entergy Nuclear Vermont Yankee and Entergy Nuclear Operations (jointly "Entergy") implemented as part of the power uprate of Vermont Yankee. Lamont pf. at 4; Deehan reb. pf. at 7–8.

80. Our ruling on the rate treatment of the \$835,946 is set forth below in Section VI.A.

41. CVPS has conducted a preliminary review of the facts relating to the outage and concluded that these incremental costs are eligible for recovery under the Ratepayer Protection Plan. Deehan reb. pf. at 8.

42. CVPS filed a petition asking the Board to resolve the issue of whether the cause of the outage was related to the uprate (and thus reimbursable by Entergy) or not. Docket 6812-A, Order of 3/4/05.

Yankee Atomic and Connecticut Yankee Incremental Decommissioning

43. Yankee Atomic is a retired single 185 MW nuclear power generating station located in Rowe, Massachusetts. Yankee Atomic recovers its costs through power contracts that remain in effect until decommissioning is complete (expected for 2006). Jewell-Kelleher YA (Yankee Atomic) pf. at 2–4.

44. Connecticut Yankee is a retired single 583 MW nuclear power generating station located in Haddam Neck, Connecticut. The plant is currently being decommissioned (a process that is expected to be complete in 2007). Jewell-Kelleher CY (Connecticut Yankee) pf. at 2–4.

45. CVPS pays a share of Connecticut Yankee decommissioning costs through the power contracts. Jewell-Kelleher CY pf. at 3.

46. In late 2002, CVPS received a forecast that the decommissioning costs for Yankee Atomic and Connecticut Yankee would be substantially higher than had been previously forecast. At that time, CVPS sought and received an accounting order from the Board authorizing deferral of the incremental decommissioning expense. Tr. 2/18/05 at 56 (Frankiewicz); Gibson pf. at 41; Page pf. at 13.

47. Decommissioning costs for Connecticut Yankee, Yankee Atomic, and Maine Yankee (in which CVPS also had an ownership share) have increased recently. A large part of this increase is due to the United States Department of Energy's failure to remove the spent nuclear fuel (as required by contract). Increased security costs and the declining financial markets (which reduced decommissioning fund earnings) have also contributed. As a result, the decommissioning funds are inadequate to meet expected decommissioning expenses. Page pf. at 13–18; exh. CVPS CJF-15 at 5 (Page response).

48. Yankee Atomic has filed and settled with the Federal Energy Regulatory Commission ("FERC") to renew collections at a higher level to cover its decommissioning obligations. Connecticut Yankee is also requesting a large increase to its current obligations. Watts pf. at 8; Page pf. at 18–19.

49. The decommissioning costs for Connecticut Yankee and Yankee Atomic as set out in FERC tariffs have increased by approximately \$2,345,200 during Rate Year 1.⁸¹ Exh. DPS-CVPS-Joint-2.

3. Regulatory Liabilities

6062 VEPPi Cost Mitigation (and Docket 6270)

50. On June 9, 2003, the Board issued an accounting order authorizing CVPS to defer the saving credits achieved through the implementation of the Memorandum of Understanding approved in Docket 6270. Gibson pf. at 41–42.

51. CVPS recorded these savings, with carrying costs, as regulatory liabilities. Gibson pf. at 41–42.

52. The Company has been recording regulatory liabilities for savings it has been accruing through March 31, 2005. Frankiewicz reb. pf. at 10.⁸²

53. The savings to be accrued after March 31, 2005, were reflected in Rate Year 2 purchased power costs. The amount of these savings are \$373,500. Frankiewicz reb. pf. at 10; exh. DPS-CVPS-Joint-2 at 1.

54. The balance for the credit in Rate Year 1 should be \$561,482. CVPS includes both Rate Year 1 amortization, and the savings to be achieved after March 31, 2005 (which were also included in the Company's power cost calculation), in its Rate Year 2 balance. These two amounts should be removed from the Rate Year 2 starting balance, which should be \$371,321 (\$561,485 less Rate Year 1 amortization of \$187,164). Exh. DPS-L&A-11 at page 10 of schedule 8; exh. DPS-L&A-12 at page 10 of schedule SR8.

81. Our ruling on the rate treatment of the \$2,345,547 is below in Section VI.A.

82. The Department corrected exh. DPS-L&A-12 at page 10 of schedule SR8 to reflect the removal of Rate Year 1 amortization of \$187,164. Tr. 2/18/05 at 77-78 (Schultz).

6460 Millstone Decommissioning

55. Pursuant to the settlement approved in Docket Nos. 6120 and 6460, and in accordance with a letter to the Board dated September 10, 2002, the Company recorded on its books a regulatory liability equal to the retail amount of Millstone III decommissioning expense included in the Docket Nos. 6120 and 6460 settlement cost of service which were subsequently not billed to or paid by the Company. Gibson pf. at 41–42.

56. Since the Company does not expect to pay this expense in Rate Year 1 or Rate Year 2, the Company continues to increase the regulatory liability up to the day before each rate year begins. Gibson pf. at 41–42.

57. Presently, CVPS is not paying any Millstone III decommissioning expense, and no decommissioning costs are included in the cost of service for either Rate Year 1 or Rate Year 2. Page pf. at 21.

58. The Rate Year 1 rate base balance for the 6460 Millstone Decommissioning regulatory liability should be \$382,664, and Rate Year 1 amortization should be \$127,555. Schultz and DeRonne pf. at 31; Gibson pf. at 42; exh. DPS-L&A-11 at page 11 of schedule 8.

59. Rate Year 2 rate base should be increased \$404,937 to reflect the reduction in the credit balance from \$596,268 to \$191,331. The amortization credit should be reduced by \$110,952 to \$127,555. Exh. DPS-L&A-11 at page 11 of schedule 8.

5800 Brockway Mills Refund

60. On July 30, 2003, the Board accepted a proposal by the Company to record a credit received from Brockway Mills, Inc. related to Docket No. 5800 in Account 254.0 (Other Regulatory Liabilities) with carrying costs. Gibson pf. at 42–43.

61. CVPS recorded these savings until the next rate case as a regulatory liability. Gibson pf. at 42–43.

62. The Rate Year 1 rate base balance for the 5800 Brockway Mills Refund regulatory liability should be \$161,064, and Rate Year 1 amortization should be \$53,688. Schultz and DeRonne pf. at 32; exh. DPS-L&A-11 at page 12 of schedule 8.

63. The removal of Rate Year 1 amortization and carrying costs from the Rate Year 2 rate base balance reduces the credit by \$66,305 (from \$146,837 to \$80,532). *Id.*

6270 Non-Petitioning Utilities

64. In accordance with Docket No. 6270, the Company received reimbursement for legal fees from non-petitioning utilities that were to benefit from the agreements reached to mitigate the cost of Rule 4.100 Qualifying Facility Contracts with VEPPI. This amount was required to be set aside for the benefit of ratepayers, and to be addressed in the Company's next rate proceeding. Gibson pf. at 43.

65. The Rate Year 1 amortization needs to be removed from the Rate Year 2 rate base balance, which should be reduced by \$106,396 from \$265,991 to \$159,595. The amortization credit in Rate Year 2 does not require an adjustment. Schultz and DeRonne pf. at 32; exh. DPS-L&A-12 at page 13 of schedule 8.

66. The Rate Year 1 rate base balance for the 6270 Non-Petitioning Utilities regulatory liability should be \$319,189, and Rate Year 1 amortization should be \$106,396. *Id.*

Summary

67. The deferral account balances and amortization expenses for Rate Year 1 and Rate Year 2 which we find reasonable, in accordance with the findings above, are summarized as follows:

	Balance to Amortize 3/31/04	Amortize or Expense in RY 1	Balance to Amortize 3/31/05	Original Accrual	Per- iod
<u>Regulatory Assets</u>					
Dkt 5980 DUP DSM ⁸³	\$ -	\$ -	\$ -	1/01-3/04	5 yr.
Dkt 5980 DUP ACE	145,830	72,915	72,915	7/00-9/04	2 yr.
Dkt 6270 IPPs	141,803	47,268	94,535	7/01-11/03	3 yr.
Dkt 6330 Retail Choice	6,163	2,054	4,109	7/01-1/02	3 yr.
<u>Deferred Debits</u>					
VT Yankee Fuel Rod Repair*	2,770,739	923,580	1,847,159	6/02, 12/03	3 yr.
VY Incr. Costs due to Sale	5,954,406	1,984,802	3,969,604	9/02-1/03	3 yr.
VY - June 04 Fire Outage*	-	835,946	-	6/04-7/04	Exp.
YA Incr. Decommissioning*	-	1,917,317	-	6/03-3-05	Exp.
CY Incr. Decommissioning*	-	428,140	-	12/04-3/05	Exp.
Subtotal Reg. Assets & Deferred Debits	9,018,941		5,988,322		
<u>Regulatory Liabilities</u>					
6062 VEPPi Cost Mitigation	561,482	187,161	374,321	3/98-3/04	3 yr.
6062 VEPPi Cost Mitigation*	-	373,500	-	4/04-3/05	Exp.
6460 Millstone Decom.	382,664	127,555	255,109	3/02-3/05	3 yr.
5800 Brockway Mills Refund	161,064	53,688	107,376	12/96, 3/03	3 yr.
6270 Non-Petitioning Util.	319,189	106,396	212,793	3/03-4/03	3 yr.
6460 Earnings Cap 02 & 03 ⁸⁴	TBD	TBD	TBD	12/02, 03	4 yr.
Subtotal, not incl. earnings cap	1,424,399		949,599		
Total (Net), not incl. earnings cap	7,594,542		5,038,723		

* See Section VI.A, below, for a discussion of our decision with respect to these deferral accounts.

83. See Section V.C, below, for the explanation of the zero balance in Distributed Utility Planning Demand-Side Management deferral account.

84. As explained in Section III, below, we require CVPS to recalculate its overearnings in 2001, 2002, and 2003, as part of its compliance filing in these proceedings. The balance in the 6460 Earnings Cap 02 & 03 regulatory liability account, the amortization amount, and the rate base effects will be determined by this recalculation.

Exh. DPS-L&A-11 at pages 3–14 of schedule SR8; exh. DPS-L&A-12 at pages 3–14 of schedule SR8; exh. DPS-CVPS-Joint-2.

68. The rate base effects of our decisions regarding deferral accounts are summarized below:

	RY1 Rate Base per CVPS COS	Rate Year 1 Rate Base Adjustment	RY2 Rate Base per CVPS COS	Rate Year 2 Rate Base Adjustment
<u>Regulatory Assets</u>				
Dkt 5980 DUP DSM ⁸⁵	\$ 345,417	\$ (345,417)	\$ 378,779	\$ (378,779)
Dkt 5980 DUP ACE	136,791	(27,418)	164,549	(73,854)
Dkt 6270 IPPs	118,169	-	118,169	(47,268)
Dkt 6330 Retail Choice	5,136	-	5,136	(2,053)
<u>Deferred Debits</u>				
VT Yankee Fuel Rod Repair*	2,644,783	(335,834)	2,900,125	(1,514,755)
VY Incr. Costs due to Sale	4,962,005	-	5,441,060	(2,463,856)
VY - June 04 Fire Outage*	-	-	744,254	(744,254)
YA Incr. Decommissioning*	1,294,322	-	2,889,194	(2,112,601)
CY Incr. Decommissioning *	-	-	382,237	(368,868)
Subtotal of Reg. Assets & Deferred Debits	9,506,623	(708,669)	13,023,503	(7,706,288)
<u>Regulatory Liabilities</u>				
6062 VEPPi Cost Mitigation*	467,902	-	820,205	(539,466)
6460 Millstone Decom.	318,887	-	596,268	(404,937)
5800 Brockway Mills Refund	134,220	-	146,837	(66,305)
6270 Non-Petitioning Util.	265,991	-	265,991	(106,369)
6460 Earnings Cap 02 & 03 ⁸⁶	2,745,032	TBD	3,003,094	TBD
Subtotal	3,932,032	-	4,832,395	(1,117,077)
Total (Net), not incl. earnings cap	5,574,591	(708,669)	8,191,108	(6,589,211)

85. See Section V.C, below, for the explanation of the zero balance in Distributed Utility Planning Demand-Side Management deferral account.

86. As explained in Section III, below, we require CVPS to recalculate its overearnings in 2001, 2002, and 2003, as part of its compliance filing in these proceedings. The balance in the 6460 Earnings Cap 02 & 03 regulatory liability account, the amortization amount, and the rate base effects will be determined by this recalculation.

* See Section VI.A, below, for a discussion of our decision with respect to these deferral accounts.

Exh. DPS-L&A-11 at page 1 of schedule SR8; exh. DPS-L&A-12 at page 1 of schedule SR8.

C. Deferred but Not Subject to Rate Recovery

69. CVPS's deferred accounts include certain deferred debits and regulatory liabilities which are not subject to recovery in rates. Exh. CVPS-JHG-15.

70. The deferred debit for incremental tax expense due to the Vermont Yankee sale does not accrue carrying charges, nor has any tax due to the sale been assessed. *Id.*

71. In April, 2001, the Board approved an accounting order authorizing CVPS to record SFAS 133 unrealized gain or loss on derivative instruments and hedging activities, including CVPS's sell-back arrangement with Hydro-Québec, as a deferred asset or liability. The deferred asset or liability will be eliminated when the power at issue is delivered at the contract price. No carrying charges accrue on the these balances. *Id.*

72. In Docket 6545, the Board ordered that any refunds that CVPS receives from Vermont Yankee Nuclear Power Corporation, as its share of any Nuclear Electric Insurance Liability refund (or certain other funds), should be applied to the benefit of ratepayers. The Board required the Company to consider applying these funds for the development and use of renewable resources. In accordance with CVPS's Board-approved plan for using these funds, the Company established a regulatory liability account for these funds, which are kept in an interest-bearing account. No carrying charges accrue on these amounts. *Id.*

73. The balance in deferral accounts that are not subject to rate recovery are:

	Balance 12/31/03	Carrying Charges
<u>Deferred Debits</u>		
VY Incr. Tax Due to Sale	\$ 2,887,218	No
SFAS 133 Unrealized Loss	1,295,800	No
<u>Regulatory Liabilities</u>		
SFAS 133 Unrealized Gain	444,200	No
NEIL Insurance Refund	461,242	No
Total (Net)	3,277,576	

Exh. CVPS-JHG-15.

D. Deferred for GAAP Purposes

74. In order to comply with Generally Accepted Accounting Principles ("GAAP"), the Company maintains certain deferral accounts. Exh. CVPS-JHG-16.

75. The Rural Line Extensions account reflects costs incurred by the Company to construct line extensions on behalf of customers who chose to reimburse the Company under a financing agreement for a period of years. These amounts include finance costs that are paid by the customer, and are reflected as a reduction to the Company's cost of service, according to traditional ratemaking policy. This deferred balance is reduced as customers make payments, and the associated income is recognized. *Id.* at 1.

76. The Hydro Relicensing Costs account reflects costs (such as environmental studies) incurred by the Company in order to relicense a hydroelectric facility. The costs are deferred until the FERC license is received, at which time the costs are reclassified to Electric Plant in Service, and amortized over the license period, in accordance with GAAP. There are no carrying costs accrued on these deferred costs. *Id.*

77. The IRS Tax re: VIDA Bonds deferred charge is related to an IRS settlement in 1983 concerning the tax treatment of the interest on bonds issued to finance the Bradford hydro facility. The balance does not accrue carrying charges and is reduced through a monthly amortization to Account 930.2, until 2012. *Id.*

78. The Intangible Asset-Supplemental Retirement Plan deferred charge represents the unamortized expense for the non-qualified supplemental retirement benefit plan for certain retired officers and directors. There are no carrying costs accrued. The deferred balance is reduced through charges to a non-operating expense (below-the-line) to reflect the current year's expense and declining obligations under this plan. *Id.*

79. CVPS reflects certain portions of the costs and revenues associated with Yankee Atomic and Connecticut Yankee decommissioning as "deferred for GAAP purposes." In addition, as described above, CVPS's deferral accounts include deferred costs associated with incremental decommissioning expenses, which will be amortized and recovered in rates. Carrying costs are not accruing on the GAAP-deferred balance. The deferred asset balance is reduced as decommissioning costs are incurred and paid to the sponsors. *Id.* at 2; see finding 46, above.

80. The Company follows the accrual method of accounting, as defined by GAAP. As such, at the end of every accounting period, costs for work performed by employees between the last payroll period-end date and the last day of the accounting period are estimated and recorded to O&M expense and capital projects. This deferred balance represents the accrued payroll related to capital projects. There are no carrying costs accrued. The total balance is reversed in the next accounting period. *Id.*

81. The Miscellaneous Deferred Debits account includes miscellaneous deferred charges, such as work in progress, items that are to be reimbursed, and items whose proper final disposition is uncertain, in accordance with the FERC definition for Account 186. These items do not accrue carrying charges and are reclassified as receivables, expenses, or assets when additional information is obtained. *Id.*

82. The New Hampshire Pilot Stranded Costs regulatory liability account is related to the Connecticut Valley Electric Company's New Hampshire pilot program and was written off in 2004 as part of the Connecticut Valley Electric Company sale transaction. Carrying costs were not accrued. *Id.*

83. The Millstone Asset Retirement Overfunding regulatory liability account is the difference between the SFAS 143 Asset Retirement Obligation and the decommissioning trust fund asset balance. It is not being returned to ratepayers in this rate proceeding because the plant

is currently operating and the ultimate decommissioning cost is not known. Carrying costs are not accrued. The liability balance will be ultimately decreased when decommissioning of the asset is complete. *Id.*

84. There is no dispute about the accounting treatment for costs and revenues that are deferred for GAAP purposes, and we find such treatment is reasonable. The amounts in these accounts are as follows:

	Balance 12/31/03	Carrying Charges
<u>Deferred Debits</u>		
Rural Line Extensions	\$ 32,358	Yes
Hydro Relicensing Costs	3,470,481	No
IRS Tax re: VIDA Bonds	43,399	No
Intangible Asset/Suppl. Retirement Plan	201,298	No
YA Incr. Decommissioning	6,345,255	No
CY Incr. Decommissioning	10,347,262	No
Accrued Payroll	95,615	No
Other Deferred Debits	85,155	No
Subtotal	20,620,823	
<u>Regulatory Liabilities</u>		
New Hampshire Pilot Stranded Costs	50,238	No
Millstone Asset Retirement	890,507	No
Subtotal	940,745	
Total (Net)	19,680,078	

Exh. CVPS-JHG-13 at Attachment PSB 1-1A; exh. CVPS-JHG-16.

Discussion

In Docket 6866, we considered a Memorandum of Understanding between CVPS and the Department under which the parties agreed that CVPS's rates would be frozen during 2004, with earnings in excess of an allowed 10.5 percent return on equity applied for the benefit of CVPS's ratepayers. During our review of that agreement, we found that CVPS had a high, and swiftly

increasing, level of deferred costs on its books, which we found troubling.⁸⁷ We concluded that these large deferrals were a significant concern and observed that the deferred balance had been increasing substantially. We noted that cost deferrals "result in current charges being passed on to future ratepayers, possibly resulting in intergenerational inequities."⁸⁸ When a company adds carrying-costs to deferral accounts, the effect is similar to an increase in rate base for future recovery. Our Order conditionally accepting the MOU reflected our concern; we approved the agreement, but only if both the Department and CVPS affirmatively agreed to a number of conditions which were designed to begin addressing the large deferral account balances. In essence, we found that "level rates for current ratepayers must not be achieved by excessively deferring costs for future ratepayers to bear."⁸⁹

Neither CVPS nor the Department fully accepted the conditions in the Docket 6866 Order; as a result, our concerns about the level of deferred costs were not then addressed.⁹⁰ The amount of deferred costs remains large — \$23,216,368 (excluding the Docket 6460 Earnings Cap regulatory liability). In these proceedings, CVPS has proposed to reduce its deferral accounts, primarily by recovering the deferred amounts from ratepayers over a three-year period. CVPS acknowledges that recovering these deferred costs will improve its balance sheet from a financial perspective.⁹¹ The Company considers the rate impact of the recovery of these costs through amortization to be small and manageable.⁹² In general, the Department does not oppose these recoveries.

The reference to deferral accounts actually encompasses a large number of regulatory assets (Account 1823), deferred debits (Account 1860), and regulatory liabilities (Account 2540) that can be broadly grouped into four broad categories, each of which has different rate and policy implications:

87. In fact, we have been concerned with CVPS's increasing deferrals for some time. As CVPS noted: "The Board's had a concern actually all the way back to 5701/5724. It's the same concern of the high level of deferred debits, and reg assets" Tr. 1/11/05 at 117 (Frankiewicz).

88. Docket 6866, Order of 1/27/04 at 15–16.

89. Docket 6866, Order of 1/27/04 at 3.

90. The deferral accounts are not solely regulatory assets, which reflect costs deferred by CVPS for future recovery from ratepayers. They also include regulatory liabilities, *i.e.*, amounts that CVPS must return to ratepayers.

91. CVPS Brief at 228.

92. *Id.*

- those that are deferred and currently being recovered in rates;
- those proposed to be amortized commencing either in Docket 6946 or Docket 6988;
- those that are deferred, but not subject to rate recovery; and
- those that are deferred for Generally Accepted Accounting Principles ("GAAP") purposes.⁹³

In these proceedings, we are concerned primarily with the first two categories of deferrals. These categories — which total \$23,216,368 in deferred obligations — reflect expenses from prior periods that CVPS has deferred, generally pursuant to the terms of Board-issued accounting orders.⁹⁴ In this section, we address four issues:

- (1) Whether the amortization of the deferral accounts commences in Rate Year 1 (as proposed by the Department) or Rate Year 2 (as advocated by CVPS);
- (2) Whether the amortization period for most deferrals for which CVPS proposes to begin amortizing in these proceedings should be over three years (as proposed by CVPS) or over six years (as recommended by AARP);
- (3) Whether we should require CVPS to establish a "reverse" deferral account that would continue to track amortizations after the end of the recovery period, so that these amounts could be returned to ratepayers (in the case of regulatory liabilities) or recovered from ratepayers (for regulatory assets); and
- (4) The use of accounting orders for events that are not extraordinary.

In addition, in separate sections of this Order, we address issues concerning specific deferral accounts.⁹⁵

93. As an example of an account deferred pursuant to GAAP, CVPS is required to pay the decommissioning costs for several nuclear plants of which it is a part owner. The rates for these payments are set by FERC, and will run through 2010. GAAP requires that CVPS record the total of this future stream of payments as a regulatory liability.

94. The accounting orders contain explicit provisions stating that they no have bearing on ratemaking treatment, including the amount (if any) that the Company can subsequently recover in rates.

95. These include recovery of Distributed Utility Planning Demand-Side Management and Distributed Utility Planning Account Correcting for Efficiency deferrals, the amount of the Vermont Yankee 2002 Mid-Cycle Outage deferral, and whether to expense or amortize incremental decommissioning costs for Connecticut Yankee and Yankee Atomic and for the VEPPI Cost Mitigation. See Sections V.C, V.D, and VI.A.

Starting Rate Year for Amortization

These proceedings are the first rate proceedings since CVPS deferred many of the costs and revenues identified above. Therefore, this is the time for us to decide the recoverability and amortization of those costs. CVPS and the Department disagree on when amortization of deferred costs and revenues should begin — in Rate Year 1 or Rate Year 2. This issue applies to all of CVPS's deferral accounts for which it is requesting to begin amortization in these proceedings.

The Company's cost-of-service filings for both Rate Year 1 and Rate Year 2 reflect amortization of the deferred costs net of regulatory liabilities as an expense. However, CVPS did not reduce the deferred balances shown in Rate Year 2 as necessary to reflect the amortizations in Rate Year 1. The Company claims that it did not intend to begin amortization in Rate Year 1, but that the Rate Year 1 amortization was for "illustrative" purposes.⁹⁶ The Company argues that the amortization was reflected in Rate Year 1 "in order to present an accurate Cost of Service" ⁹⁷ CVPS further asserts that the amortization cannot be reflected in Rate Year 1 because, in addition to being "illustrative," it is not "known." CVPS bases this latter argument on two points: first, the Company asserts that it has not recorded the amortization on its books of account. Second, CVPS contends that the accounting orders authorizing the deferrals state that the costs will be deferred until the next "rate proceeding;" thus, the amortization cannot be reflected in Rate Year 1 because Docket 6946 is a "rate investigation," not a "rate proceeding." Finally, CVPS argues that it is wrong to start amortization in Rate Year 1 because CVPS will not have an opportunity to earn its return on equity.

The Department proposes accounting for amortization of deferred accounts beginning in Rate Year 1, and reflecting the impact of that amortization on the deferred balance in Rate Year 2, in a manner consistent with the Company's original filing.⁹⁸

For several reasons we conclude that all deferrals should be amortized beginning in Rate

96. Frankiewicz reb. pf. at 5–7.

97. Gibson reb. pf. 11/15/04 at 12. It is not readily apparent how including an expense item that the Company did not intend to recognize is "more accurate" than simply reflecting the Company's proposal to start amortization in Rate Year 2.

98. Schultz and DeRonne reb. pf. at 23.

Year 1.⁹⁹ First, the accounting orders authorizing the deferrals provided that the amounts would be deferred until the next rate case. Just like Docket 6988, Docket 6946 is a proceeding in which we will determine CVPS's rates. In this regard, there is no distinction between whether the case commenced under 30 V.S.A. § 227(a) or § 227(b).¹⁰⁰ Second, commencing the amortization in Rate Year 1 will allow CVPS to recover these expenses and remove them from the Company's books more quickly. Third, amortization in Rate Year 1 will contribute to rate stability by making the rate decrease smaller. If amortization were to begin in Rate Year 2, the rate decrease in Rate Year 1 would be one percent larger.¹⁰¹ Fourth, such treatment provides a close match between the period in which the costs were incurred and the time period in which they are expensed. This is important for equity reasons – the ratepayers who benefit from a service should be the ones to pay for it. Finally, beginning amortizations in Rate Year 1 allows CVPS to record them in the same accounting period as it recognizes the 2004 earnings that it deferred pursuant to our February 18, 2005, Accounting Order, thereby also contributing to rate stability.

We are not persuaded by CVPS's claim that starting amortization in Rate Year 1 will prevent the Company from recovering those costs. This assertion might have some merit if we found that CVPS's Rate Year 1 rates were below its costs. Here, however, we find that CVPS's rates are excessive and must be reduced. The rate reduction we find is necessary includes the amortization as an expense. If we accepted CVPS's proposal to start the amortization in Rate Year 2, the Rate Year 1 rate reduction would be larger, by the amount of the Rate Year 1 amortization expense. CVPS thus fully recovers these costs if, as we require, amortization begins in Rate Year 1.¹⁰²

We also find no merit in CVPS's assertion that it cannot record this amortization on its books. In fact, we flatly reject CVPS's apparent theory that it can control ratemaking treatment of an issue through its own unilateral decisions about how to book items. The proper purpose of

99. Our conclusion might have been different if the evidence had shown that CVPS had a revenue deficiency in Rate Year 1. If that had been the case, requiring CVPS to begin amortizing its deferral accounts in Rate Year 1 would have increased the revenue deficiency and might have affected the Company's ability to earn its allowed rate of return.

100. CVPS acknowledged this fact during the hearings. Tr. 1/12/05 at 29 (Gibson).

101. Frankiewicz reb. pf. at 8.

102. See also *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944).

such accounting may be to try to predict regulatory decisions; it is certainly not to supplant them. As CVPS acknowledged at the hearing, it can record the expense in Rate Year 1 if we order it.¹⁰³ We do so here.

Our decision to begin amortization in Rate Year 1 requires that we adjust the Rate Year 2 amortization expense to reflect the Rate Year 1 recoveries. Through our decision, the amortization of deferrals net of regulatory liabilities is known and measurable in Rate Year 1 and the deferred balances for Rate Year 2 should be reduced by the expense reflected in Rate Year 1.

Amortization Period

CVPS proposed that the deferred balances should be amortized over three years.¹⁰⁴ The Department agreed with CVPS on the amortization time period. AARP proposes that deferred costs should be amortized over six years, with the understanding that each cost should be included in rate base, and that no carrying costs should accrue once amortization begins. AARP does so to reduce the rate effect of the amortization expense.

We find that for regulatory assets, deferred debits, and most regulatory liabilities that will begin amortization in Rate Year 1, the amortization period proposed by CVPS is reasonable. These amortization periods provide an appropriate balance between the need to reduce deferred balances quickly, and the benefit of mitigating the rate impact during that time. We understand that, if we amortized the deferrals over a longer period, the annual amortization expense would be less, which would initially cause a larger rate reduction. But such a course would keep the deferrals on the books longer and exacerbate inter-generational equity concerns. Nevertheless, for the reasons we discuss in Section III above, we conclude that a four-year amortization of the earnings cap regulatory liability is appropriate to ensure that ratepayers receive the funds owed them in a timely fashion, while also reducing the impact on the Company's earnings and cash flow.

103. Tr. 1/11/05 at 69 (Frankiewicz).

104. Except for Distributed Utility Planning Account Correcting for Efficiency (2 years) and Distributed Utility Planning Demand-Side Management (5 years). Gibson pf. at 37.

Reverse Amortization

We now turn to the ratemaking treatment that should occur when the amortization period of a particular deferred cost or revenue expires, and that amount has been fully amortized.

The Department recommends that the Board rule that when the amortization period of a regulatory asset ends, any associated rate revenues should be booked as a regulatory liability for the benefit of ratepayers and not flow through to income, which inures ultimately to the benefit of shareholders. The Department proposes that this process be reversed when the amortization period of a regulatory liability ends. The Department maintains that such treatment prevents over-recovery of assets, a violation of generally accepted accounting principles and FERC guidelines.

CVPS would have the Board rule that when a regulatory asset is fully amortized, the associated rate revenue (that is still being recovered in rates) flows to the Company's current income. The reverse is true for regulatory liabilities. This treatment would be in effect until the Company's next rate change. CVPS argues that this policy provides an incentive for efficient behavior, helps it avoid frequent, expensive rate cases, and is consistent with traditional ratemaking. CVPS contends that the Department's proposal represents a ratemaking policy change, and should be considered more broadly.

To date, we generally have not required CVPS or other companies to record a reverse amortization expense after the deferral is fully amortized.¹⁰⁵ This means that when an asset is fully recovered, CVPS continues to recover the same amount in rates. As CVPS suggests, at times of rising prices, this can help mitigate the need for rate increases as the Company effectively receives an "increase" as each asset is fully recovered.

When deferral accounts were used sparingly, this regulatory approach did not have much effect. Now, as we have explained, CVPS has many deferrals. In two years, when the assets that begin amortization in Rate Year 1 are fully recovered, more than one percent of CVPS's rates would be associated with expenses that no longer exist.

We are thus persuaded that it is appropriate to adopt the policy urged by the Department.

105. One exception is demand-side management expenses, for which the Board directed CVPS to track the amortization in a similar manner to what the Department recommends. See Section V.C for further explanation.

To allow the continued recovery of a regulatory asset after it has been fully amortized (and fully recovered in rates), does indeed constitute over-recovery of that asset. Moreover, the fact that the reverse effect is true for regulatory liabilities provides the balance which the Company contends is lacking.¹⁰⁶ Accordingly, our ruling is consistent with the Department's recommendation: upon the expiration of a regulatory asset or liability, the corresponding rate revenue shall be booked as a reverse amortization in an opposing regulatory liability or asset account.

Accounting Orders

The significant cost deferrals that CVPS seeks to begin to recover through amortization in these proceedings have largely arisen because the Company experiences certain events that increase its expenses. GAAP allows regulators to require a company to record its costs and revenues in a different time period than a non-regulated company would. In Vermont, we authorize such treatment through accounting orders or through explicit rulings in cases that require the Company to record costs and earnings in a specific way. We usually consider accounting order requests without providing general public notice of the request (except to the Department) and without evidentiary hearings.¹⁰⁷ We have counterbalanced this policy by affirmatively stating that the accounting order affected solely the accounting treatment of the relevant costs (or revenues) and that it had no precedential effect on the ratemaking treatment of those costs (or revenues). As we ruled in Docket 5983, such limitations are essential, given the abbreviated procedures employed:

We must stress that, in the absence of full notice and opportunity for hearing on a request for an accounting order, such an order will not have final effect in a later rate proceeding under §§ 225–227, and it would be wrong for any party to think otherwise.¹⁰⁸

One set of costs and revenues that the Board may authorize a regulated company to defer

106. It is important to recognize that these amortizations are, themselves, the result of special accounting treatment that permits present recovery of past expenses. Reversing the amortization when the underlying regulatory asset or liability is fully amortized not only is consistent with the rationale behind that accounting treatment — to reflect an expense or income over an extended, but not indefinite time period — but also promotes more accurate recognition of such expenses and income.

107. See 30 V.S.A. § 221.

108. Docket 5983, Order of 6/8/98, at 20.

under GAAP are those associated with exceptional or extraordinary events. In fact, the bulk of the deferrals that we consider in these proceedings fall into this category; in reliance upon the Company's assertions that the events which cause these costs or revenues are "extraordinary," we issued a number of accounting orders that allow CVPS to "book and defer" costs and revenues. For example, in 2003 we authorized CVPS to defer the incremental decommissioning expenses for Yankee Atomic and Connecticut Yankee. These were large added expenses that CVPS could not reasonably anticipate.

An extraordinary event or transaction under GAAP is one that is "abnormally and significantly different from the ordinary and typical activities of the company, and which [sic] would not reasonably be expected to occur in the foreseeable future."¹⁰⁹ The GAAP standard encompasses four key considerations in determining whether an event is "extraordinary," and therefore merits a request for an accounting order. These considerations are:

- Is the amount material?
- Was the event unplanned?
- Was the event beyond CVPS's management control?
- Is the problem unusual, abnormal, and not likely to be repeated?¹¹⁰

The evidence in these proceedings and our experience with accounting orders raises questions about our recent practice. In particular, we have two sets of concerns: (1) whether we have been issuing such Orders too readily; and (2) whether the current practice is unfairly "one-sided" in that it tends to reflect cost deferrals, but not necessarily revenue deferrals (which would tend to benefit shareholders more than ratepayers). For example, some of the expenses that CVPS seeks to recover through deferrals relate to unplanned outages at Vermont Yankee. CVPS has suggested that such outages meet the GAAP standard because each outage has a different cause.¹¹¹ This interpretation of the GAAP standard, however, fails to consider that breakage at a power plant is not an unusual event. On the contrary, CVPS (in its power planning) and we (in our ratemaking) expect power plants to have outages for reasons that cannot be anticipated

109. Gibson reb. pf. 11/15/04 at 13–14.

110. Page reb. pf. at 8–9.

111. Taken to its logical extreme, CVPS's argument would justify special accounting treatment for all outages at power plants, except those that are recurring.

(which is why CVPS includes a forced outage rate in the power cost models).

Similarly, the list of deferrals shows many cost deferrals, but few revenue deferrals. In 2004, for example, CVPS sought an accounting order for \$835,000 in incremental replacement power costs associated with a fire at Vermont Yankee. At the same time, CVPS did not request special treatment for a \$6.6 million gain that it received on the sale of Connecticut Valley Electric Company. Ratepayers would thus have the costs deferred, but the revenues would, in the absence of an earnings cap, go to shareholders.

Moreover, CVPS itself acknowledged that it has used accounting orders as a substitute for a fuel adjustment clause.¹¹² The Company suggests that this approach is reasonable since every successful candidate for extraordinary cost treatment need not satisfy all four of these key considerations, but that a balance of these considerations is appropriate.¹¹³ We understand that each event is different and that it is impossible to delineate a bright line test to define extraordinary events. But it seems very unlikely that an event or transaction could be considered extraordinary unless it met all four of the GAAP criteria.

We are also concerned that broad use of the accounting orders as if they were a fuel adjustment clause has the affect of altering the balance of risks that we consider in setting the Company's return on equity. The risk level we find for CVPS, and on which we base the Company's allowed return on equity, encompasses the fact that Vermont does not have a fuel adjustment clause. If CVPS uses these accounting orders in such a way as to mirror (in large part) the effect of such a clause, we would need to downgrade our assessment of the risks that CVPS faces.

At the present time, we do not envision specific changes to our accounting order practices. However, we will expect CVPS to better explain how future requests meet the GAAP requirements and, most importantly, why they are extraordinary. In addition, we will give

112. ". . . as soon as a bill comes in, and we pay it, absent an accounting order, it would have to be expensed. It comes out of both columns, regulatory liability and the regulatory asset, and if it's so extraordinary, you know, it's not deemed to be in rates, then it's not recovered. If it's expensed. *That's why we have to have the accounting order. Certainly in the absence of a fuel and purchase power clause here in Vermont.*" Tr. 1/11/05 at 124–126 (Frankiewicz) (emphasis added).

113. Page reb. pf. at 9; tr. 11/2/04 at 169–170 (Gibson).

consideration to requiring CVPS to commence amortization in the same manner that it would for plant additions (i.e., at the time the event is completed), rather than deferring those costs indefinitely.

Finally, we want to make clear that, when we issue an accounting order, we are authorizing the Company to defer such costs, not mandating that treatment. We acknowledge that in the past, some accounting orders included the phrase "is authorized and shall defer . . ." However, this language was not intended to require deferral until the next rate proceeding or to prevent the earlier recovery of the deferred costs, as CVPS has suggested it did.

V. RATE BASE

A utility's rate base represents the unrecovered prudent investment in facilities dedicated to the provision of a public service. Upon this rate base, the utility earns a risk-adjusted return comparable to similarly-situated companies. Unlike revenue or expense adjustments, a dollar change in rate base does not result in a dollar reduction in the expected earning potential of a regulated utility. Rather, a dollar reduction in rate base equals a reduction in expected earnings equal to the utilities' cost of capital¹¹⁴ times the amount of the rate base adjustment. Thus, assuming a 10.0 percent cost of capital and a rate base reduction of \$100, the expected earnings of a utility would be reduced by \$10 per year.¹¹⁵

A. Plant Adjustments

Findings

Rate Year 1 Plant Adjustments

85. CVPS's original cost-of-service filings included plant additions that would increase the Company's Rate Year 1 rate base by \$7.2 million. Some of these proposed plant additions are not known and measurable. As a result, net reductions to CVPS's Rate Year 1 cost of service and rate base, by plant category, are as follows:

114. Technically speaking, a utility's cost of capital equals the weighted-average cost of capital. See Section VII for more detail.

115. A utility's income taxes would also be reduced.

Plant Category	Net Rate Base Reductions	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Distribution Substation	(\$25,846)	(\$115)	(\$450)	(\$654)
Distribution Purchases	(\$100,998)	(\$1,499)	(\$876)	(\$3,727)
Facilities	(\$53,929)	(\$314)	(\$763)	(\$1,444)
Information Systems	(\$119,290)	(\$5,948)	(\$4,428)	(\$13,034)
Communication	(\$7,431)	(\$99)	(\$619)	(\$374)

Schultz and DeRonne pf. at 4–5; exh. DPS-L&A-11 at schedule 5; exh. CVPS-CJF-3.

86. CVPS's proposed Distribution Substation plant additions include costs associated with replacing the Bethel Breaker and upgrading the Weybridge 80 and 81 relays. The Bethel Breaker is not scheduled to be in service during Rate Year 1 and there is no documentation to support the cost of the Weybridge relay upgrades. Schultz and DeRonne pf. at 11.

87. CVPS's proposed Distribution Purchases plant additions include blanket work orders for regulators and meters that are significantly higher than the non-growth-related five-year averages for those items. Some of the costs requested for these blanket work orders should be disallowed. Schultz and DeRonne pf. at 13; exh. DPS-L&A-11 at schedule 5.

88. The following proposed Facilities plant additions have been cancelled or deferred beyond Rate Year 1: General office- replace computer room; GO-Switchgear upgrade; Engineering building renovations; the SOB-Tel/Data/SCADA unit; and card readers for fuel dispensers. Schultz and DeRonne pf. at 15; exh. DPS-L&A-11 at schedule 5.

89. CVPS duplicated two of its proposed Information Systems plant additions in its original cost-of-service filing. The duplicates should be removed. Also, the proposed "SAN" expansion does not meet the known and measurable test and should be removed. Schultz and DeRonne pf. at 16.

90. CVPS cancelled two of its proposed Communications Systems plant additions that were related to site improvements. Schultz and DeRonne pf. at 17; exh. DPS-L&A-11 at schedule 5.

91. Deferred hydroelectric relicensing costs in Rate Year 1 amounted to \$29,231. As a result, the following changes to CVPS's cost of service and rate base are warranted:

Plant Category	Net Rate Base Addition	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Hydro Re-licensing	\$29,231	\$225	\$0	\$1,172

Schultz and DeRonne pf. at 19; exh. DPS L&A-11 at page 2 of schedule SR 3.

92. As a result of adjustments to CVPS's cost of service and rate base, CVPS's proposed rate base should be reduced in Rate Year 1 by \$278,263, net of relicensing costs. Accumulated depreciation should be reduced by \$7,750, deferred income taxes should be reduced by \$7,136, and depreciation expense should be reduced by \$18,061, also net of relicensing costs. Exh. DPS-L&A-11 at schedule 5 and page 2 of schedule SR3.

Rate Year 2 Plant Adjustments

93. CVPS's original cost-of-service filings included plant additions that would increase the Company's Rate Year 2 rate base by \$20.9 million.¹¹⁶ Exh. CVPS-CJF-7.

94. CVPS's capital budgets for 2005 and 2006 have not yet been approved. Some projects that were originally part of CVPS's cost-of-service filings may be cut as part of the budget approval process. Schultz and DeRonne sur. pf. at 7; tr. 1/10/05 at 175 (G. White); tr. 11/1/04 at 75 (Jones).

Production

95. CVPS did not provide cost support for the Glen Station modernization and Silver Lake Automation projects. In addition, based on the projects' late projected in service date, the projects may slip beyond the end of the rate year. Therefore, the following reductions to CVPS's requested cost-of-service and rate base should be made:

116. CVPS's proposed plant additions are shown on lines 2 through 9 of exh. CVPS-CJF-7.

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Production	(\$436,539)	(\$2,496)	(\$6,978)	(\$11,933)

Schultz and DeRonne pf. at 7; exh. DPS-L&A-12 at page 1 of schedule 5.

Transmission Substations

96. Some of CVPS's proposed additions to Transmission Substation plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost-of-service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Taxes	Depreciation Expense
Transmission Substations	(\$388,737)	(\$2,989)	(\$5,169)	(\$9,893)

Schultz and DeRonne pf. at 9–10; exh. DPS-L&A-12 at page 1 of schedule 5.

Transmission Lines

97. Some of CVPS's proposed additions to Transmission Line plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost-of-service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Transmission Lines	(\$353,083)	(\$1,775)	(\$5,811)	(\$8,499)

Schultz and DeRonne pf. at 10–11; exh. DPS-L&A-12 at page 1 of schedule 5.

Distribution Substations

98. CVPS did not provide any cost support for the Weybridge relay upgrade project.
Schultz and DeRonne pf. at 11.

99. CVPS did not provide sufficient information to conclude that a portable transformer will actually be purchased. The Company did not provide evidence to justify its need, and the description provided indicates that the portable transformer is a discretionary item. Schultz and DeRonne pf. at 12.

100. CVPS has not provided any information to support the cost of the new spare substation transformer. In addition, the transformer appears to be a discretionary purchase and it is not known whether it will be acquired. Schultz and DeRonne pf. at 12.

101. CVPS has described the Breaker Replacement as a project for the replacement of old breakers that no longer operate reliably. However, the Company did not provide supporting information regarding this project. Schultz and DeRonne pf. at 12.

102. The following reductions to CVPS's requested cost of service and rate base should be made to remove costs associated with proposed projects that do not meet the known and measurable standard:

Plant Category: Distribution Substations	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Weybridge Relay Upgrade Project	(\$20,000)	(\$427)	(\$578)	(\$540)
Portable Transformer	(\$784,615)	(\$10,474)	(\$5,768)	(\$21,747)
Sub. Transformer Replacement Spare	(\$75,385)	(\$336)	(\$1,311)	(\$1,908)
Breaker Replacement	(\$54,692)	(\$230)	(\$899)	(\$1,309)

Schultz and DeRonne pf. at 11–13; exh. DPS-L&A-12 at page 2 of schedule 5; findings 98–101, above.

103. Some of CVPS's other proposed additions to Distribution Substations plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost-of-service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Distribution Substations	(\$117,308)	(\$658)	(\$1,870)	(\$3,042)

Schultz and DeRonne pf. at 12; exh. DPS-L&A-12 at page 2 of schedule 5.

104. Total reductions to proposed Distribution Substation plant additions should be:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Distribution Substations	(\$1,052,000)	(\$12,125)	(\$10,426)	(\$28,546)

Exh. DPS-L&A-12 at page 2 of schedule 5.

Distribution Purchases

105. CVPS did not provide documentation supporting the inclusion of two meter test equipment purchases in rate base in Rate Year 2. These meter test equipment purchases are considered discretionary. As a result, the following reductions to CVPS's requested cost of service and rate base should be made:

Plant Category: Distribution Purchases	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Meter Test Equipment	(\$67,398)	(\$829)	(\$713)	(\$2,418)

Schultz and DeRonne pf. at 14; exh. DPS-L&A-12 at page 2 of schedule 5.

106. Some of CVPS's other proposed additions to Distribution Purchases plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost of service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Distribution Purchases	(\$256,756)	(\$7,908)	(\$4,506)	(\$9,108)

Schultz and DeRonne pf. at 13–14; exh. DPS-L&A-12 at page 2 of schedule 5.

107. Total reductions to proposed Distribution Purchases plant additions should be:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Distribution Purchases	(\$324,154)	(\$8,737)	(\$5,219)	(\$11,526)

Exh. DPS L&A-12-at page 2 of schedule 5.

Facilities

108. The project identified as SOB-Tel/Data/SCADA was not allowed into rate base in Rate Year 1. CVPS flowed some of the costs associated with that project through to Rate Year 2. As a result, the following reductions to CVPS's requested rate base and cost of service should be made:

Plant Category: Facilities	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
SOB-Tel/Data/SCADA	(\$25,967)	(\$619)	(\$224)	(\$708)

Exh. DPS-L&A-12 at page 2 of schedule 5; finding 88.

109. Some of CVPS's other proposed additions to Facilities plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost of service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Facilities	(\$89,046)	(\$1,611)	(\$1,926)	(\$2,532)

Schultz and DeRonne pf. at 15–16; exh. DPS-L&A-12 at page 2 of schedule 5.

110. Total reductions to proposed Facilities plant additions should be:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Facilities	(\$115,013)	(\$2,230)	(\$2,150)	(\$3,240)

Exh. DPS-L&A-12 at page 2 of schedule 5.

Information Systems

111. CVPS duplicated two of its proposed Information Systems plant additions in its original cost-of-service filing (the Liebert HVAC and the 3835 Replacement). The duplicates should be removed. Also, the proposed "SAN" expansion does not meet the known and measurable test and should be removed. Schultz and DeRonne pf. at 16.

112. CVPS did not provide sufficient information to support the cost of the Main Frame project. In addition, the project's scheduled completion date is so late in Rate Year 2 that the project may not be completed during the rate year. Schultz and DeRonne pf. at 17.

113. The following reductions to CVPS's requested rate base and cost of service should be made to remove costs associated with proposed projects that do not meet the known and measurable standard:

Plant Category: Information Systems	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Liebert HVAC	(\$71,527)	(\$6,998)	(\$6,686)	(\$4,539)
3835 Replacement	(\$38,877)	(\$9,930)	(\$2,885)	(\$6,809)
SAN Expansion	(\$38,600)	(\$5,345)	(\$4,734)	(\$6,751)
Mainframe upgrade	(\$11,135)	(\$81)	(\$197)	(\$1,056)

Exh. DPS-L&A-12 at page 3 of schedule 5; findings 111–112, above.

114. Some of CVPS's other proposed additions to Information Systems plant are not known and measurable due to unsupported or undocumented costs. As a result, the following reductions to CVPS's requested cost of service and rate base should be made:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Information Systems	(\$32,502)	(\$1,596)	(\$2,294)	(\$6,463)

Schultz and DeRonne pf. at 17; exh. DPS-L&A-12 at page 3 of schedule 5.

115. Total reductions to proposed Information Systems plant additions should be:

Plant Category	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Information Systems	(\$192,641)	(\$23,950)	(\$16,796)	(\$25,618)

Exh. DPS-L&A-12 at page 3 of schedule 5.

Communications

116. CVPS's original cost of service filing erroneously omitted \$454,494 of proposed Communications plant additions. This error should be corrected. Schultz and DeRonne pf. at 18; exh. DPS-L&A-12 at page 3 of schedule 5.

117. CVPS did not provide sufficient support for the requested video conferencing equipment. Schultz and DeRonne pf. at 18.

118. CVPS cancelled two of its proposed Communications Systems plant additions that were related to site improvements. Exh. DPS-L&A-12 at page 3 of schedule 5; finding 90.

119. The following reductions to CVPS's rate base and cost of service should be made to remove costs associated with proposed projects that do not meet the known and measurable standard:

Plant Category: Communication Systems	Net Rate Base Reduction	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Video Conference Equipment Unit Pilot	(\$10,164)	(\$85)	(\$973)	(\$483)
Video Conference Equipment	(\$7,692)	(\$16)	(\$152)	(\$209)
Site Improvements/ Additions	(\$9,975)	(\$483)	(\$1,595)	(\$504)
Emergency Generator Site	(\$5,250)	(\$275)	(\$831)	(\$264)

Exh. DPS-L&A-12 at page 3 of schedule 5; findings 117–118, above.

120. Total additions to proposed Communications Systems plant additions should be:

Plant Category	Net Rate Base Addition	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Communications Systems	\$381,279	\$11,771	\$52,170	\$18,770

Exh. DPS-L&A-12 at page 3 of schedule 5.

121. CVPS incurred costs to relicense its hydroelectric dams. Those costs have been deferred. As a result, the following increases to CVPS's cost of service and rate base should be made:

Plant Category	Net Rate Base Addition	Accumulated Depreciation	Def. Inc. Tax	Depreciation Expense
Hydro Re-licensing	\$1,431,538	\$15,299	\$0	\$51,780

Schultz and DeRonne pf. at 19.

122. As a result of adjustments to CVPS's cost of service and rate base, the Company's proposed rate base should be reduced in Rate Year 2 by \$1,049,350, net of relicensing costs. Similarly, accumulated depreciation should be reduced by \$27,232, deferred income taxes should be reduced by \$379 and depreciation expense should be reduced by \$28,705, net of relicensing cost. Schultz and DeRonne pf. at 19; exh. DPS L&A-12 at page 3 of schedule 5 and schedule SR3.

Discussion

Plant investment is typically the largest component of a utility's rate base. This investment is constantly changing as utilities acquire new plant and perform periodic maintenance and replacement of their existing plant. When the Board sets rates for an investor-owned utility such as CVPS, it determines the utility's plant investment for the test year, and then adjusts that investment for known and measurable changes.¹¹⁷

CVPS's plant investment at the end of the test year in the instant proceedings was approximately \$483 million.¹¹⁸ The Company's original cost-of-service filings in these proceedings include additions to utility plant investment that increase CVPS's Rate Year 1 rate base by \$7.2 million, the Company's Rate Year 2 rate base by \$20.9 million. CVPS asserts that all these proposed additions are known and measurable. The DPS disagrees with this assertion, arguing instead that many of the Company's proposed additions are not known and measurable. However, in a recommendation that is more lenient than traditional Vermont ratemaking

117. This section of our Order refers to gross plant investment. In order to determine a utility's rate base, an additional step is required — the gross plant investment must be reduced by the amount of accumulated depreciation on that plant. Also, reductions may be required if a plant investment was not prudently made or is not "used and useful" for the delivery of service.

118. CVPS-CJF-3.

practice, the DPS does not propose that the Board disallow all the costs associated with proposed plant additions that are not known and measurable. Instead, the DPS contends that the Board should allow a percentage of unsupported plant costs (with the percentage varying by type of plant), because it is reasonable to expect that some non-growth-related capital spending will occur, and it is appropriate for CVPS to earn a return of and on plant necessary for the Company to meet its service quality and reliability standards.¹¹⁹

Our evaluation of CVPS's proposed plant additions begins with a review of the known and measurable standard, as defined by the Vermont Supreme Court, and as applied by this Board. The Vermont Supreme Court has defined the known and measurable standard as "changes that are measurable with a reasonable degree of accuracy and have a high probability of being in effect in the adjusted test year."¹²⁰ The Board has consistently held, including in CVPS's last fully-litigated rate case, that witnesses' representations alone are not sufficient support for a project to meet the Court's known and measurable standard. Rather, the Board has required some tangible work-product that shows that the project is likely to actually be completed; examples include work orders, cost-benefit analyses, or other types of written support for a project's cost and completion date.

In these proceedings, we conclude that CVPS has not met its burden of showing that all of its proposed additions meet the known and measurable standard. CVPS failed to provide appropriate cost support for many of its projects, and did not demonstrate that all of its proposed projects would be in service during the appropriate rate year. CVPS attempted to overcome this lack of documentation by asserting that all of its projects were known and measurable because they have gone through the Company's capital budgeting process and experts within the Company had stated that they would occur.¹²¹ We are not persuaded by this argument. The Company's own witness admits that CVPS's capital budgets for 2005 and 2006 have not yet been approved, and that some projects included in CVPS's cost-of-service filing may be cut during the budget approval process.¹²² In addition, the DPS has shown that some projects that were

119. DPS Brief at 4, 14.

120. *In re GMP*, *supra*, at 381.

121. G. White reb. pf. at 7.

122. *See*, finding 94, above.

included in past capital budgets were later cancelled.

The DPS identifies several specific projects included in CVPS's cost-of-service filings that do not meet the known and measurable standard,¹²³ and recommends that the Board disallow the costs associated with these projects. After reviewing the evidence and the parties' arguments, we conclude that these proposed adjustments are reasonable, and we hereby accept them.

We also accept the DPS's recommendation that we depart from a strict application of the known and measurable standard, and allow CVPS to include in rates a portion of the costs that it has not shown meet that standard. No party has opposed allowing this portion of CVPS's costs in rates, and we determine that such an approach is appropriate in these particular circumstances. Therefore, and without ruling on the merits of the DPS's underlying rationale, we accept the DPS's proposed levels of plant additions to be included in rate base.

In addition, we accept an adjustment to CVPS's Rate Year 1 and Rate Year 2 rate bases and costs of service that is agreed upon by CVPS and the DPS. This adjustment corrects an omission in CVPS's original cost-of-service filings related to deferred hydroelectric relicensing costs.

Thus, for the reasons explained above, we conclude that CVPS should reduce its proposed Rate Year 1 rate base by \$278,263, and its Rate Year 2 rate base by \$1,049,350. In addition, CVPS should make the corresponding reductions to accumulated depreciation, deferred income taxes, and depreciation expense that are shown in findings 92 and 122, above.

Two additional items deserve discussion. First, CVPS argues that all of its proposed projects are necessary for the Company to provide service to customers, and that it is inappropriate for the Board to deny recovery of the costs associated with these projects. This argument reflects a misunderstanding about the issue before us today. We are not being asked to decide whether CVPS will ever be allowed to recover the costs associated with a particular project. Rather, we are being asked to determine whether it is appropriate for CVPS to recover now the costs associated with a particular project that has not yet been implemented. It is very possible that some of the projects we determine are not known and measurable today will occur

123. See, findings 86–90, 95, 98–101, 105, 108, 111–112, and 117–118.

in the future. If so, CVPS can request recovery of the costs associated with those projects at such time as it can show that the projects are known and measurable.

Finally, we are concerned about the level of support CVPS filed in support of its proposed plant additions in these proceedings. This same issue arose in CVPS's last fully-litigated rate cases. In those cases, the Board rejected certain proposed changes to the Company's rate base because of a lack of supporting documentation. The Board stated that:

The company provides no support for capital additions beyond the statements of a company witness. More specifically, there are no exhibits, workpapers, underlying work orders and associated cost/benefit analysis that would enable either the Department or the Board to conclude that these investments are indeed interim period non-growth related investments.¹²⁴

We expect CVPS to present such supporting information for its proposed capital additions with its initial testimony in its future rate cases.

B. Accumulated Depreciation

Findings

123. CVPS's proposed rate base for Rate Year 1 includes an average accumulated depreciation balance of \$218,353,000. CVPS's proposed rate base for Rate Year 2 includes an average accumulated depreciation balance of \$218,978,000. Exh. CVPS-CJF-3; exh. CVPS-CJF-7.

124. CVPS's Rate Year 2 accumulated depreciation should be increased by \$15,299 to correct an error in CVPS's original cost-of-service filing related to hydroelectric relicensing costs. Schultz and DeRonne pf. at 19.

125. For each proposed plant addition that is disallowed, there is a corresponding adjustment to accumulated depreciation. CVPS's accumulated depreciation should be reduced by \$7,975 in Rate Year 1 and \$42,529 in Rate Year 2 to reflect the changes to CVPS's plant balances. Schultz and DeRonne pf. at 19; exh. DPS-L&A-11 at schedule 5; exh. DPS-L&A-12 at page 3 of schedule 5.

126. Rates currently being collected by CVPS assume recovery of depreciation expense.

124. Dockets 5701/5724, Order of 10/31/94 at 37.

Depreciation is being recorded on CVPS's books. Tr. 11/2/04 at 152 (Gibson); tr. 1/11/05 at 76–78 (Frankiewicz).

127. CVPS's method for calculating its adjustment to accumulated depreciation is to increase test-year accumulated depreciation by 50 percent of the test-year depreciation expense. Frankiewicz reb. pf. at 3.

128. CVPS's method for calculating interim-period depreciation results in an average accumulated depreciation for Rate Year 1 of \$214,707,441. However, the accumulated depreciation balance on the books of the Company on March 31, 2004, (the day before Rate Year 1 begins) is \$216,722,616. Exh. DPS-34; tr. 1/11/05 at 75–78 (Frankiewicz).

129. CVPS's method for calculating interim-period depreciation results in an average accumulated depreciation for Rate Year 2 of \$222,737,225. Given that, according to CVPS's original cost-of-service filings, CVPS's accumulated depreciation balance as of March 31, 2004, (the day before Rate Year 1 begins) is \$216,714,895, and that CVPS has requested annual depreciation expense of \$16,059,627, this means that CVPS's accumulated depreciation balance at the beginning of Rate Year 2 will be \$232,774,522. It is not mathematically possible to have an average Rate Year 2 balance of \$222,737,225 when the beginning balance is \$232,774,522. Schultz and DeRonne reb. pf. at 21; exh. DPS-L&A-10.

130. CVPS's original filing includes an error in the calculation of annualized test-year depreciation expense. This expense was \$16,059,627 (\$1,338,302 per month) in the original filing, while the correct amount should be \$16,090,512 (\$1,340,876 per month), for an annual difference of \$30,888, or 0.19 percent. Exh. DPS-34.

131. If the correct amount of monthly depreciation is used, CVPS's accumulated depreciation balance as of March 31, 2004, (the day before Rate Year 1 begins) is \$216,722,616, and its accumulated depreciation balance at the beginning of Rate Year 2 is \$232,813,128. Using these amounts in the analysis shown in finding 129, above, does not change the conclusion; CVPS's average accumulated depreciation for Rate Year 2 is still less than the accumulated depreciation balance at the start of Rate Year 2. Exh. DPS-L&A-10; findings 129–130, above.

132. The interim-period adjustment to accumulated depreciation should be calculated as follows:

- Add interim-period depreciation to the accumulated depreciation balance at the end of the test year to determine the accumulated depreciation balance at the end of the interim period;
- Average the accumulated depreciation balance at the end of the test year and the accumulated depreciation balance at the end of the interim period to determine the average interim-period accumulated depreciation balance;
- Subtract the average interim-period accumulated depreciation balance from the average test-year accumulated depreciation balance to determine the interim-period adjustment to accumulated depreciation.

Schultz and DeRonne sur. pf. at 19.

133. The rate-year adjustment to accumulated depreciation should be calculated as follows:

- Add rate-year depreciation to the accumulated depreciation balance at the end of the interim period to determine the accumulated depreciation balance at the end of the rate year;
- Average the accumulated depreciation balance at the end of the interim period and the accumulated depreciation balance at the end of the rate year to determine the average rate-year accumulated depreciation balance;
- Subtract the average rate-year accumulated depreciation balance from the average interim-period accumulated depreciation balance to determine the rate-year adjustment to accumulated depreciation.

Schultz and DeRonne sur. pf. at 19.

134. CVPS's average Rate Year 1 accumulated depreciation balance should be increased by \$4,015,000 to reflect interim-period and rate-year depreciation. Schultz and DeRonne pf. at 20–21; exh. DPS-L&A-11 at page 1 of schedule 6.

135. CVPS's average Rate Year 2 accumulated depreciation balance should be increased by \$20,075,000 to reflect interim-period and rate-year depreciation. Schultz and DeRonne pf. at 21; exh. DPS-L&A-12 at page 1 of schedule 6.

Discussion

Depreciation is the accounting convention that defines the pace at which utilities should recover the cost of their prudently-incurred investment in physical "plant" that is used to serve ratepayers. Accumulated depreciation is the sum of all the depreciation a utility has already collected from its ratepayers on its plant that remains in service, plus amounts collected for net

salvage and future cost of removal of that plant.¹²⁵ Each year, a utility's accumulated depreciation increases by the amount of depreciation expense that it records in its financial books, and decreases by the amount of accumulated depreciation on plant that is retired. For ratemaking purposes, gross plant is reduced by accumulated depreciation to arrive at the net plant on which a company earns a return. An increase in accumulated depreciation has the effect of reducing the rate base upon which a return is earned. Thus, an increase in accumulated depreciation results in a reduction in ultimate rates. The converse is also true — a decrease in accumulated depreciation has the effect of increasing the rate base upon which a return is earned, thereby resulting in an increase in ultimate rates.

The DPS argues that CVPS's accumulated depreciation should be adjusted in four ways:

- (1) to correct an error in CVPS's original cost-of-service filing related to hydroelectric relicensing costs (this applies to Rate Year 2 only);
- (2) to reflect the DPS's recommended disallowances of additions to CVPS's plant balances;
- (3) to reflect changes to depreciation expense resulting from the DPS's recommendations regarding net salvage rates; and
- (4) to properly reflect interim-period and rate-year depreciation.

CVPS does not contest the correction of the error relating to hydroelectric relicensing costs. It also does not contest the principle that accumulated depreciation should be adjusted to reflect changes in plant balances,¹²⁶ although it does contest the DPS's recommended changes to its plant balances (see the discussion in Section V.A, above). CVPS does not directly address the DPS's proposed changes resulting from its recommendations regarding net salvage rates; however, CVPS does contest CVPS's proposed changes to those rates (see the discussion in Section VI.D, below). In addition, CVPS acknowledges that accumulated depreciation should be adjusted to reflect interim-period depreciation, although it contests the methodology that the DPS uses to calculate interim-period depreciation. Finally, CVPS argues that accumulated depreciation should not be increased to reflect rate-year depreciation.

125. When plant is retired, the asset is removed from rate base and accumulated depreciation on that plant is removed from the utility's total accumulated depreciation.

126. Frankiewicz pf. at 23.

We have reviewed the uncontested adjustment related to hydroelectric relicensing costs described in finding 124, above, and conclude that it is appropriate and should be made. We have also reviewed the DPS's proposed adjustment to accumulated depreciation to reflect changes in CVPS's plant balances. Accumulated depreciation should be adjusted to be consistent with plant account balances. Since we have accepted the DPS's proposed adjustments to plant balances (see Section V.A, above), it is necessary to make the corresponding adjustments to accumulated depreciation. Therefore, we accept the DPS's proposed adjustment to accumulated depreciation shown in finding 125, above.

We do not accept the DPS's proposed \$903,634 reduction to the average Rate Year 1 accumulated depreciation balance, and \$2,710,902 reduction to the average Rate Year 2 accumulated depreciation balance. The DPS proposes these reductions in order to reflect its recommended change in depreciation expense related to net salvage rates.¹²⁷ As explained in Section VI.D, below, we have rejected the DPS's recommended change in depreciation expense related to net salvage rates. Consequently, it is not appropriate to make the corresponding reductions to the Rate Year 1 and 2 average accumulated depreciation balances.

Interim Period and Rate Year Depreciation

We now turn to the issue of adjusting accumulated depreciation to reflect interim-period and rate-year depreciation.

Vermont ratemaking uses a historic test year adjusted for known and measurable changes. The Vermont Supreme Court has held that, while the Board's discretion is broad, it may not reject an adjustment that is unquestionably known and measurable.¹²⁸ The Vermont Supreme Court made that statement when it required the Board to adjust test-year rate base for interim-period depreciation because (1) interim-period depreciation is known and measurable, and (2):

. . . once customers have, in effect, returned a portion of a utility's investment, they should not be required to pay for that portion a second time, once as depreciation expense and again as a return on plant value which had not been correspondingly reduced to reflect the "return of" the investment through

127. Schultz and DeRonne pf. at 21–22.

128. *In Re GMP*, *supra*.

depreciation expense payments.¹²⁹

The same principles apply to rate-year depreciation; both interim-period and rate-year depreciation are known and measurable amounts already reflected in rates as an expense. In both instances, ratepayers will have returned a portion of a utility's investment. Therefore, under the Vermont Supreme Court's standard, ratepayers should not be required to pay for that portion a second time, and the Board must recognize an adjustment to accumulated depreciation for interim-period and rate-year depreciation.

The Vermont Supreme Court's decision in *In re GMP* does address the issue of interim-period depreciation, as CVPS suggests.¹³⁰ However, the logic of the Supreme Court's decision extends beyond simple recognition of interim-period depreciation and mandates that we incorporate adjustments that are known and measurable. The Supreme Court clearly set out the public policy reason for applying the known and measurable change principle to the test-year rate base — to ensure that ratepayers do not pay for the same portion of a utility's investment twice, once as depreciation expense, and a second time as return on plant value which had not been reduced to reflect the return of a portion of the investment through depreciation expense payments. This principle applies to rate-year depreciation just as to interim-period depreciation; ratepayers will pay depreciation expense in the rate year, the amount of that expense is known and measurable, and a utility's rate base should be adjusted to reflect the recovery of that portion of its investment from ratepayers. It would be wrong for the Board to ignore the core rationale of the Vermont Supreme Court's decision in *In re GMP* and to limit the Court's holding only to the issue of interim-period depreciation.

We also reject CVPS's assertion that the anti-updating provisions of 30 V.S.A. § 225(a) undermine the Vermont Supreme Court's rationale in *In re GMP* by denying a utility an "ample opportunity" to present evidence of plant additions during the rate year.¹³¹ This assertion is not plausible on its face. Section 225(a) was in effect at the time the Supreme Court issued its

129. *In re GMP*, *supra*, at 383.

130. CVPS Brief at 153.

131. CVPS Brief at 135.

decision in *In re GMP*,¹³² yet that decision stated that GMP had had an ample opportunity to introduce evidence regarding its rate-year plant additions.¹³³ We have to infer that the Vermont Supreme Court understood 30 V.S.A. § 225(a)'s mandate at the time it considered GMP's appeal. Since the statute has not changed, the Vermont Supreme Court's decision still controls.

More significantly, CVPS did have an ample opportunity to present evidence regarding its plant additions. This opportunity was at the time that CVPS filed its costs of service in these rate cases. CVPS chose not to present sufficient evidence at that time, even though the Company knew of the limits imposed on updating by 30 V.S.A. § 225(a). Instead, CVPS provided insufficient evidence to show that its plant additions were known and measurable, and then tried to update the support for its plant additions with additional evidence months later, after the DPS pointed out the deficiencies in CVPS's initial filing. The DPS challenged this additional evidence on the grounds that it violated the anti-updating provisions of 30 V.S.A. § 225(a). After reviewing the DPS's objection, and CVPS's response to it, we struck the additional evidence from the record.¹³⁴ It is inappropriate for the Company to now blame the DPS and Vermont law for the consequences of its own timing decisions.

Calculation Methodology for Interim Period and Rate Year Depreciation Adjustments

Given that we have decided that adjustments should be made for interim-period and rate-year depreciation, we must next determine the appropriate calculation for these adjustments.

The DPS asserts that the correct methodology for calculating the adjustments for interim-period and rate-year depreciation is that which the Board has applied in recent cases involving other Vermont utilities (Dockets 6596 and 6914).¹³⁵ Essentially, this methodology calculates

132. There were minor modifications to 30 V.S.A. § 225(a) in 1999; however, the anti-updating provisions of that section were not affected.

133. "A general trend is no substitute for evidence, especially when, as here, the utility seeking the rate increase has had an ample opportunity to introduce evidence as to its adjusted test year additions to plant, and did not do so." *In re GMP*, *supra*, at 384.

134. Tr. 1/10/05 at 193–196 (Chairman Dworkin, for the Board).

135. Docket 6596 *Tariff filing of Citizens Communications Company, d/b/a Citizens Energy Services, requesting a rate increase in the amount of 40.02%, to take effect December 15, 2001*, Order of July 15, 2002 (referred to herein as the "Docket 6596 Order"); Docket 6914 *Investigation into the Existing Rates of Shoreham Telephone Company, Inc.*, Order of November 4, 2004 (referred to herein as the "Docket 6914 Order"). The DPS has used a

(1) an interim-period adjustment that is the difference between the average interim-period accumulated depreciation balance and the average test-year accumulated depreciation balance; and (2) a rate-year adjustment that is the difference between the average rate-year period accumulated depreciation balance and the average interim-period accumulated depreciation balance.¹³⁶

CVPS has calculated the interim-period depreciation adjustment using the methodology that the Board approved in Dockets 5701/5724, CVPS's last litigated rate cases. No adjustment was made in those dockets for rate-year depreciation, and CVPS did not calculate a rate-year depreciation adjustment in the instant proceedings.

We have reviewed both parties' arguments regarding the two proposed methodologies, and conclude that the DPS's methodology should be applied in these proceedings, for the reasons explained below. Therefore, we accept the DPS's proposed adjustments to average accumulated depreciation of \$4,015,000 in Rate Year 1, and \$20,075,000 in Rate Year 2.¹³⁷

Most importantly, the DPS's methodology is consistent with the Vermont Supreme Court's decision in *In re GMP* because it adjusts CVPS's accumulated depreciation for all known and measurable changes (not just interim-period depreciation), and because it ensures that ratepayers do not pay twice for the same investment.

Second, the DPS's proposed methodology is identical to the calculation methodologies that we applied in both the Docket 6596 Order and the Docket 6714 Order, and is related to the methodology that the Board had considered in Docket 5532, the case that led to the *In re GMP* ruling from the Vermont Supreme Court. Thus, the DPS's proposed methodology is consistent

similar methodology for years. Tr. 1/13/05 at 28–30 (Schultz). As most rate cases were settled, the Board did not delineate it in detail until 2002.

136. Schultz and DeRonne sur. pf. at 19.

137. The DPS's adjustments are to the adjusted test-year accumulated depreciation balances shown in CVPS's original cost-of-service filings in these proceedings. In other words, the DPS used its methodology to calculate the appropriate interim-year and rate-year adjustments to test-year accumulated depreciation balances to arrive at the rate-year average accumulated depreciation balance, then proposed an adjustment equal to the difference between that rate-year average accumulated depreciation balance, and the rate-year average accumulated depreciation balance shown in CVPS's original cost-of-service filings.

with recent Board precedent.¹³⁸

Third, and importantly, the DPS has shown that CVPS's methodology for calculating its adjustment to accumulated depreciation produces mathematically impossible results in which CVPS's average rate-year accumulated depreciation balance is less than CVPS's accumulated depreciation balance at the beginning of the rate year (see findings 128 and 129, above). This persuades us that CVPS's methodology does not protect ratepayers from paying twice for the same investment as *In re GMP* requires. Therefore, rates based on CVPS's methodology would not be just and reasonable, and we must revisit the interim-period calculation methodology that we accepted 10 years ago in Dockets 5701/5724 in order to arrive at just and reasonable rates.¹³⁹

We are not persuaded by CVPS's multiple arguments in support of its position on this issue. First, CVPS claims that because its methodology has not been found to be unjust or unreasonable, it should be accorded a presumption of reasonableness.¹⁴⁰ As explained above, we reach the opposite conclusion — using CVPS's methodology would not result in just and reasonable rates. None of CVPS's other arguments can overcome this fundamental failing of its proposed methodology. Nevertheless, the discussion below addresses CVPS's other arguments regarding this issue.

Case-by-Case Development of the Law

Many of CVPS's arguments in support of its methodology fail to recognize the critical

138. We acknowledge that this methodology is different than the one we approved 10 years ago in Dockets 5701/5724. The intent of the two methodologies was the same — to implement the Vermont Supreme Court's decision in *In re GMP*, *supra*. However, after considering the evidence in more recent cases and the instant proceedings, we conclude that the DPS's methodology more closely adheres to the Vermont Supreme Court's decision.

139. Consistent with both Vermont Supreme Court and United States Supreme Court precedents, our overall revenue determination in this proceeding is based on a functional end-result test. *See, Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944); *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989); "It is not the theory, but the impact of the rate order which counts." *Id.* at 314. *See also Verizon v. FCC*, 535 U.S. 467, 526, 122 S. Ct. 1646, 1680 (2002): "we held, as usual that a rate setting methodology would normally be judged only by the overall impact of the rate orders."

140. CVPS Brief at 136–137.

role of case-by-case evolution in the development of the law,¹⁴¹ and the responsibility of a tribunal to "discard(s) the old rule when it finds that another rule of law represents what should be according to the established and settled judgement of society."¹⁴² Given these well-established legal principles, CVPS should not be surprised that during the 10 years since the Board issued its order in Dockets 5701/5724 (CVPS's last fully-litigated rate cases), the Board has modified some of the ratemaking methodologies that it accepted in those dockets. It would be incorrect for the Board to apply to CVPS only those methodologies that it accepted in Dockets 5701/5724, and to ignore any orders it has issued in the last 10 years in litigated cases involving companies other than CVPS that altered those ratemaking methodologies.¹⁴³

Similarly, it is inconsistent with the case-by-case development of the law (not to mention the seven-month standard of Title 30) for CVPS to assert that the Board should convene a proceeding or workshop for all utilities before making changes to any previously accepted ratemaking methodology. The Board must resolve disputed issues in cases before it. It is impractical, unrealistic, and contrary to judicial economy, to expect the Board to never change a regulatory policy or calculation methodology, except in generic proceedings that involve all the state's utilities.

In addition, CVPS's argument that any significant changes to accumulated depreciation should only be implemented prospectively in a subsequent proceeding is incompatible with well-established administrative law precedent that policies may be changed at the same time they are applied.¹⁴⁴ This precedent makes clear that, contrary to CVPS's assertions, it is not unfair to

141. Docket 5132, Order of 7/31/87 at 31. "[t]here is thus a very definite place for case-by-case evolution of statutory standards." Docket 5132, Order of 7/31/87 at 33, quoting *SEC v. Chenery Corp.*, (Chenery II), 332 U.S. 194, 203 (1947).

142. Docket 5132, Order of 7/31/87 at 31, quoting Justice Cardozo in *THE NATURE OF THE JUDICIAL PROCESS* (1921) at 151, quoting, with approbation, *Day v. Connecticut Co.*, 89 Conn. 74, 99.

143. We are concerned that the Company's Chief Financial Officer believes that the Board should ignore previous ratemaking orders issued in litigated cases involving companies other than CVPS. See tr. 1/11/05 at 152–153 (Gibson). This contrasts sharply with CVPS's argument that it is entitled to any favorable aspects of our treatment of GMP.

While most settlement agreements involving CVPS and GMP expressly state that they are not precedential, orders in litigated cases are precedential for all parties within a jurisdiction, not just for those who were parties to the individual cases. This is the common regulatory standard throughout our nation.

144. Docket No. 5132, Order of 7/31/87 at 33–34.

apply a result that is consistent with other cases in which CVPS was not a party. The question before the Board in the instant proceedings is: what is the appropriate accumulated depreciation adjustment calculation methodology for CVPS to use? CVPS was certainly given notice in the DPS's direct prefiled testimony that this would be an issue in these proceedings, and the Company had an opportunity during the rebuttal phase of these proceedings to present evidence regarding the appropriateness of applying the DPS's proposed methodology to CVPS.

Precedential Nature of Board's Orders in Dockets 6596 and 6914

Contrary to CVPS's assertions,¹⁴⁵ the Docket 6596 Order and the Docket 6914 Order are precedential. We find CVPS's multiple, scatter-shot arguments related to this issue to be unpersuasive and either inaccurate or irrelevant to the decision before us in these proceedings. Many of the Company's assertions relating to these two orders are addressed elsewhere in this Order; the discussion below focuses only on those not addressed elsewhere.

- It is irrelevant that the Docket 6596 Order did not reference prior Board or Vermont Supreme Court decisions related to accumulated depreciation, and did not state that the Board was establishing a new methodology that was to be used in all future cost-of-service studies. It is not necessary for a Board order to cite previous relevant Board and Vermont Supreme Court decisions in order for the order to be precedential. In addition, it is not necessary for a Board order to explicitly state that a particular decision should apply to other utilities in the future in order for it to serve as precedent. CVPS appears to confuse notice-and-comment rulemaking with common-law contested-case adjudication.
- The methodology we approved in Dockets 6596 and 6914 is different than that accepted by the Board 11 years ago in Dockets 5701/5724, and the two methodologies do produce different results. However, given the case-by-case evolution in the development of the law, the fact that the two methodologies differ and produce different results does not affect our decision regarding which will produce just and reasonable rates in the instant proceedings.
- No party has suggested that Citizens' agreement to the DPS's rate-year methodology in Docket 6596 should be extended to CVPS. We understand that CVPS does not agree to the DPS's proposed adjustment; that is why the issue is before us to resolve. However, the mere fact that CVPS has not agreed to a concept does not mean that this Board must reject that concept.

145. CVPS Brief at 146.

- Some small elements of the Docket 6914 Order may or may not have ambiguities;¹⁴⁶ however, that is irrelevant to our decision today regarding which methodology is most appropriate to use in the instant proceedings.

We reject CVPS's characterization of the interim-period and rate-year accumulated depreciation adjustment methodology approved by the Board in Docket 6596 as a "utility-specific penalty on Citizens."¹⁴⁷ Nowhere in the Docket 6596 Order does it state, or imply, that the accumulated depreciation adjustment we approved in that Order was a "penalty." We assume this is a reading error by CVPS, rather than a misrepresentation of the Board's Order.

Timing of Challenges

We reject CVPS's argument that it is appropriate for the Company to continue to use its proposed methodology for calculating the appropriate adjustment to accumulated depreciation because neither the DPS nor the Board challenged that methodology in any of CVPS's rate cases since Dockets 5701/5724 (until the instant proceedings). All of CVPS's rate cases since Dockets 5701/5724 resulted in bottom-line settlement agreements among the parties or were closed without resolution. It is unpersuasive for CVPS to argue now that a methodology should not be changed because the old methodology was not challenged in cases that were settled or closed. Furthermore, as the Board stated in Docket 5983:

. . . the rate-making process relies upon the use of evidentiary presumptions to facilitate reaching a conclusion about the overall justness and reasonableness of rates without requiring an exhaustive review of hundreds or thousands of detailed cost of service items in every rate case; according to Board practice, in each rate case, a utility's filing receives the benefit of a rebuttable presumption that 'expenditures claimed to support the rates were reasonable and prudent.' Rate proceedings then focus on those aspects of a filing that parties choose to examine and present to the Board.¹⁴⁸

It is unrealistic to expect the DPS to challenge every possible issue in every rate case; and CVPS's litigation costs would be far higher over time if we accepted its argument to that effect today. As the Board stated in Docket 5983, requiring the DPS to litigate every potential cost

146. CVPS argues that the Docket 6914 Order's description of the steps taken to calculate the adjustments was circular (for example, adding interim depreciation expense to average interim year accumulated depreciation).

147. CVPS Brief at 154.

148. Docket 5983, Order of 2/27/98 at 18–19 (footnote omitted).

item in every rate case would be "an outcome inimical to the administrative process, and likely impossible to comply with within the statutory period allowed for utility rate cases."¹⁴⁹ This same rationale applies to the Board. The Board can, and often does, raise issues in rate cases that no party has addressed. However, it is not feasible for the Board to review in detail every item not addressed by a party. Thus, the fact that neither the DPS nor the Board challenged CVPS's methodology for calculating the adjustment to accumulated depreciation in CVPS's prior rate cases is unpersuasive. The issue has been raised in these proceedings, and in this Order, we resolve the dispute regarding it.

Retroactive Ratemaking

Given the schedule in Docket 6946, which CVPS itself proposed, Rate Year 1 is almost over. That does not mean, however, that we are engaging in prohibited retroactive ratemaking by applying the DPS's proposed methodology to CVPS in Rate Year 1.¹⁵⁰ On the contrary, 30 V.S.A. § 227(b) specifically provides that when the Board, on its own motion, opens an investigation into a utility's rates, the final order shall be retroactive.¹⁵¹ Our decision today is consistent with the statute's requirements that we (1) determine just and reasonable rates, and (2) apply our decision regarding those rates retroactively.

149. Docket 5983, Order of 2/27/98 at 19.

150. CVPS also asserts that it would be retroactive ratemaking to apply the DPS's proposed methodology to CVPS in Rate Year 1 because the Board's decision in Docket 6914 was not issued until well after the filing of the cost-of-service studies in these proceedings. We conclude that this argument is incorrect. The timing of the Board's decision in Docket 6914 is irrelevant for the purpose of deciding the issue in these proceedings. As discussed above, well-established administrative law holds that policies may, and sometimes should, be changed at the same time they are applied. Thus, the Board could, if it found the evidence in these proceedings supported it, apply a new accumulated depreciation adjustment policy. The key question under Vermont law is whether that methodology is reasonably directed towards our goal of establishing just and reasonable rates. *In re Green Mountain Power Corp.*, 142 Vt. 373, 380 (1983).

151. 30 V.S.A. § 227(b) states, in relevant part:

If the board does make its determination within such seven months then its final order shall be retroactive to the day that the proceedings were instituted and such final order shall contain a directive that the company, other than a common carrier of passengers by motor vehicle, shall repay to the persons from whom collected between the time the proceedings were instituted and the final order all sums which the board determines are in excess of the rates ultimately found to be just and reasonable.

As described in more detail in the Procedural History, CVPS committed to extend the statutory seven-month deadline as part of its scheduling proposal, which the Board accepted.

Cost Recovery

CVPS asserts that the DPS's proposed adjustment violates 30 V.S.A. § 218(a), because, according to the Company, it denies CVPS the opportunity to recover the costs of the plant necessary to serve customers, thereby making the Company's rates "insufficient."¹⁵² This is not so — the DPS's proposed adjustment does not deny CVPS recovery of its legitimate costs, it simply ensures that the Company only recovers those costs once.

Finally, CVPS argues that the DPS's adjustment reduces the Company's ability to recover the costs of its capital assets, promotes more frequent utility rate cases, and burdens regulatory lag.¹⁵³ This argument is closely linked to CVPS's assertions regarding its inability to provide evidence supporting its rate-year plant additions, because of the anti-updating provisions of 30 V.S.A. § 225(a). We have already addressed CVPS's arguments regarding this point. CVPS chose not to present supporting evidence at the time the statute requires such evidence to be presented. If the results of the Company's decision are more frequent utility rate cases and increased regulatory lag, CVPS must accept responsibility for the consequences of its own actions.

Correction to Annualized Test Year Depreciation Expense

No party has asked that the depreciation expense and accumulated depreciation calculations be revised to reflect CVPS's correction of its annualized test-year depreciation expense described in finding 130, above. Nevertheless, we conclude that the error should be corrected. Therefore, we require CVPS, as a part of its compliance filing in these proceedings, to modify the DPS's recommended adjustments to rate-year average accumulated depreciation in both Rate Years 1 and 2 to reflect the correct value of annualized test-year depreciation expense.¹⁵⁴

152. CVPS Brief at 136–137.

153. CVPS Brief at 138.

154. As explained in Section VI.D, below, we also require CVPS to modify the adjustment to depreciation expense to reflect this correction.

C. Distributed Utility Planning Demand-Side Management

Findings

136. CVPS is seeking recovery of Distributed Utility Planning Demand-Side Management expenditures incurred from January 1, 2001, through December 31, 2003. The total Distributed Utility Planning Demand-Side Management expenditures for this period, including carrying costs and adjustments, are \$359,864. These expenditures are reasonable, as they were incurred to acquire demand-side management resources from high use customers in identified constrained transmission and distribution areas in CVPS's service territory. Welch pf. at 2; exh. CVPS-JHG-14 at Attachment PSB 1-2.

137. Under the terms of the Memorandum of Understanding approved by the Board in Dockets 6120 and 6460, CVPS's current base rates include the collection of \$195,546 each year for recurring Distributed Utility Planning Demand-Side Management costs. This Memorandum of Understanding became effective July 1, 2001. Therefore, only half that amount, or \$97,773, was collected from ratepayers in 2001 for recurring Distributed Utility Planning Demand-Side Management costs. Welch pf. at 2–3; tr. 1/12/05 at 160–161 (Frankiewicz).

138. CVPS's Distributed Utility Planning Demand-Side Management expenditures for 2001 through 2003 should be adjusted for the amount of recurring Distributed Utility Planning Demand-Side Management costs recovered from ratepayers in rates during those years. When this calculation is performed, CVPS's Distributed Utility Planning Demand-Side Management deferral account has a negative balance of \$184,479. Welch pf. at 2–3; tr. 1/12/05 at 161–162 (Frankiewicz).

139. All of the amounts associated with the Distributed Utility Planning Demand-Side Management regulatory asset should be removed from CVPS's cost of service and rate base because CVPS has already fully recovered these amounts from ratepayers. The removal results in a \$76,759 reduction to amortization expense and a \$345,417 reduction to rate base in Rate Year 1. In Rate Year 2, the removal results in a reduction to amortization expense of \$84,173 and a reduction to rate base of \$378,779. Schultz and DeRonne pf. at 24–25; exh. DPS-L&A-11 at page 2 of schedule 8, and schedule 15; exh. DPS-L&A-12 at page 2 of schedule 8, and schedule 15.

140. The (\$184,479) balance in CVPS's Distributed Utility Planning Demand-Side Management deferral account should be returned to ratepayers. Tr. 1/12/05 at 161–162 (Frankiewicz).

141. The adjustments to the balance in CVPS's Distributed Utility Planning Demand-Side Management deferral account should be reflected in the calculation of CVPS's overearnings in 2001, 2002, and 2003, pursuant to the 6120/6460 MOU. Tr. 1/13/05 at 14 (Schultz).

Discussion

There is no dispute regarding the amount of CVPS's Distributed Utility Planning Demand-Side Management expenditures for the period 2001 through 2003 that is appropriate to be recovered. There is also no dispute regarding the amount of recurring Distributed Utility Planning Demand-Side Management expenditures that were included in CVPS's rates during that time period. There is a dispute regarding how those recurring expenditures should be used to adjust the amount of Distributed Utility Planning Demand-Side Management expenditures that CVPS now seeks to recover.

The Board's January 11, 1995, Order in Dockets 5701/5724 granted CVPS's request to amend the Board's October 31, 1994, Order in those same dockets so that it was clear that:

. . . the Company dedicate all C&LM [Conservation and Load Management] dollars [that are] included in *its rate year cost of service as C&LM Recurring Amounts* to its C&LM programs and that any amounts not expended in a particular year for such purposes be held for use in subsequent years or for eventual return to ratepayers.¹⁵⁵

The DPS argues that the amount of CVPS's Distributed Utility Planning Demand-Side Management costs should be adjusted in each year (2001, 2002, and 2003) by the amount of recurring Distributed Utility Planning Demand-Side Management expenditures collected from ratepayers in those years. When this calculation is performed, and any amounts not spent in a particular year are carried forward to future years, the balance in CVPS's Distributed Utility Planning Demand-Side Management deferral account is a negative \$184,479.

155. Dockets 5701/5724, Order of 1/11/95 at 2, 3 (italics in original). "Conservation and Load Management" is an older term that is synonymous with Demand-Side Management.

CVPS does not contest that all Distributed Utility Planning Demand-Side Management amounts reflected in CVPS's last rate case cost of service that were not expended in a particular year for such purposes should be held for use in subsequent years.¹⁵⁶ In addition, CVPS admits that ratepayers are entitled to a refund of \$184,479.¹⁵⁷ However, CVPS argues that the adjustment for recurring expenditures should only be made in 2001. The Company asserts that the adjustment should not be made in 2002 or 2003 because CVPS was subject to an earnings cap, and the recurring amounts not properly applied to 2002 and 2003 Distributed Utility Planning Demand-Side Management balances caused part of CVPS's overearnings adjustment that is included in its overearnings regulatory liability. CVPS argues that the DPS's adjustment is not necessary for years 2002 and 2003 because the appropriate amount will be returned to ratepayers through the overearnings adjustment. CVPS further asserts that if the Board does accept the DPS's adjustment to Distributed Utility Planning Demand-Side Management balances, the Board should reduce the overearnings deferral amounts to avoid double counting these amounts.¹⁵⁸

CVPS is correct in noting that making the DPS's proposed adjustment for recurring Distributed Utility Planning Demand-Side Management expenditures for 2002 and 2003, without making a corresponding adjustment to CVPS's overearnings for those years, would result in a double recovery by ratepayers. This logic is similar to that which underlies our determination in Section V.B regarding interim-period and rate-year accumulated depreciation. There, we required an adjustment to ensure that ratepayers do not pay CVPS twice for the same investment; here, we require an adjustment to ensure that CVPS does not pay back ratepayers twice for the same refund.

To properly implement the requirements of our January 11, 1995, Order in Dockets 5701/5724, we conclude that the adjustment for recurring Distributed Utility Planning Demand-Side Management expenditures should be made in each of the three years (2001, 2002, and 2003), effectively removing the Distributed Utility Planning Demand-Side Management asset

156. CVPS Reply Brief at 96.

157. Tr. 1/12/05 at 162 (Frankiewicz).

158. CVPS Reply Brief at 96–97.

from the list of deferral accounts shown on exh. CVPS-4A. Based on the Board's January 11, 1995, Order in Dockets 5701/5724, the difference between what CVPS collected in rates for Distributed Utility Planning Demand-Side Management recurring expenses, and its actual expenses in 2001, 2002, and 2003, (\$184,479) should be returned to ratepayers.¹⁵⁹ We require CVPS to reflect this decision in its compliance filing in these proceedings.

Furthermore, to avoid double-recovery by ratepayers, our decisions regarding CVPS's Distributed Utility Planning Demand-Side Management deferral account, including our decision that the excess recurring expenses be returned to ratepayers, should be reflected in the calculation of CVPS's overearnings in 2001, 2002, and 2003. As explained in Section III, we require CVPS to recalculate its overearnings for 2001, 2002, and 2003, using the cost-of-service methodology proposed by the DPS, as modified by the Board. Consistent with our decision that CVPS should not have deferred its Distributed Utility Planning Demand-Side Management costs because it had already recovered them from ratepayers, the Company's actual Distributed Utility Planning Demand-Side Management expenditures in each of those three years should be included in the calculation of its overearnings for 2001, 2002, and 2003. In addition, CVPS's return to ratepayers of \$184,479 in excess Distributed Utility Planning Demand-Side Management collections should be included in the 2003 overearnings calculation.

159. This decision is consistent with the Vermont Supreme Court's decision in *In re GMP, supra*, which prohibited the Board from reducing GMP's rate base to credit ratepayers for the amount of amortization expenses that exceeded the projected amounts for demand-side management expense in the adjusted test year. The key fact is that in the case decided by the Vermont Supreme Court, the Board had not stated that demand-side management expenses would be subject to special accounting treatment at the time the rates including those expenses were set. This is not the case with respect to CVPS. On the contrary, in Dockets 5701/5724, the Board granted the Company's request to establish a special accounting treatment for demand-side management expenses. Our decision today simply requires CVPS to implement the special accounting treatment that it, itself, had requested. If *In re GMP, supra*, were to prohibit such use of deferral accounting, this could have significant adverse affects on Vermont utilities, including CVPS (especially in light of CVPS's substantial deferred account balances discussed in Section IV, above).

D. Distributed Utility Planning Account Correcting for Efficiency ("ACE")¹⁶⁰**Findings**

142. The formula for calculating ACE is gross lost revenue minus the production savings and other incremental operational savings experienced by CVPS during the calculation period. Welch pf. at 4; Gibson pf. reb. at 16–17.

143. The avoided costs used to compute ACE should be adjusted for the latest available market price information and forecasts for the remainder of the period. Bentley reb. pf. at 2–3; Welch pf. at 3–4.

144. The balance in the Distributed Utility Planning ACE deferral account, including carrying costs, as of March 31, 2004, should be \$145,830. Exh. DPS-L&A-11 at page 3 of schedule 8.

145. The balance of the Distributed Utility Planning ACE deferral account should be amortized over two years. Gibson pf. at 37; Docket No. 5980, Order of 9/30/99 at A-19 (Paragraph 33 of the Memorandum of Understanding).

Discussion

CVPS and the DPS agree in principle on the formula that should be used to calculate ACE. They also agree that the most recent information available should be used to calculate the production savings component of the ACE calculation. However, they disagree about the most recent avoided cost information. As a result, they have calculated slightly different Distributed Utility Planning ACE amounts.

CVPS and the DPS also disagree on when the amortization of the balance in the Distributed Utility Planning ACE deferral account should start. CVPS argues that it should begin at the start of Rate Year 2 while the DPS asserts that it should begin at the start of Rate Year 1. For the same reasons articulated in Section IV, above, regarding when the amortization of other deferral accounts should begin, we conclude that the amortization of the Distributed Utility Planning ACE deferral account should begin at the start of Rate Year 1.

160. Distributed Utility Planning ACE is designed to enable a utility to collect its net lost revenues resulting from the installation of energy efficiency measures, pursuant to Distributed Utility Planning, in its service territory between rate cases.

Given this decision, it is necessary for us to determine the balance in the Distributed Utility Planning ACE deferral account as of March 31, 2004, the end of the interim period. The most recent information available should be used to calculate the production savings component of the ACE calculation, and the latest calculations of the Distributed Utility Planning ACE amount were performed by CVPS; the DPS did not address these calculations. However, CVPS did not provide the balance in the deferral account as of March 31, 2004, including carrying costs.¹⁶¹ Based on the evidence in the record, the difference between the DPS's and CVPS's positions regarding the balance in the deferral account at the beginning of Rate Year 1 is likely to be *de minimus*.¹⁶² Since the only number in the record for the balance as of March 31, 2004, is the DPS's, and the difference appears to be so small, we will accept the DPS's number of \$145,830.¹⁶³

However, we do not accept the DPS's recommendation regarding the changes in the balance of the Distributed Utility Planning ACE deferral account during Rate Years 1 and 2. The DPS correctly determined the amount of monthly amortization (\$6,076) by dividing the balance in the deferral account at the start of Rate Year 1 by 24.¹⁶⁴ But the DPS also added to the balance in the deferral account the Distributed Utility Planning ACE related to the energy efficiency measures projected to be installed during each month of Rate Year 1.¹⁶⁵ This is not consistent with past practice in Vermont.

Traditionally, the Board approves recovery of a specified amount in an ACE deferral account, and that amount is amortized in even increments over two years. At the end of the two-year amortization period, the ACE deferral account is fully amortized.¹⁶⁶ ACE associated with

161. According to CVPS, the value of the deferral account as of March 31, 2004, *excluding* carrying costs is \$124,623. Exh. CVPS-BWB-1 shows the amount of Distributed Utility Planning ACE that is accumulated in each month from January 2000 through December 31, 2005. The figure of \$124,623 is arrived at by summing the values for each month through March 31, 2004.

162. According to the DPS, the ACE deferral balance, excluding carrying costs, as of December 31, 2005, (a date that is in the middle of Rate Year 2) is \$167,269; according to CVPS, that figure is \$172,914. Exh. DPS-CEW-2. Exh. CVPS-BWB-1.

163. See finding 144, above.

164. Exh. DPS-L&A-11 at page 3 of schedule 8.

165. Tr. 11/4/04 at 83 (DeRonne); exh. DPS-L&A-11 at page 3 of schedule 8.

166. Tr. 11/1/04 at 182–184 (Welch).

any new energy efficiency installations is deferred in a new deferral account until the utility's next rate proceeding, when it is reviewed for its appropriateness before cost recovery is allowed.¹⁶⁷ The DPS has argued that it is appropriate to change Board policy and establish what is in essence a "revolving" Distributed Utility Planning ACE account in order to ensure that CVPS does not overcollect Distributed Utility Planning ACE by continuing to collect amortization in rates beyond the point at which the deferral account is fully amortized.¹⁶⁸ This is a valid concern; however, we believe it is better addressed through the concept of "reverse amortization", which we explain in more detail in Section IV. Reverse amortization will ensure that ratepayers do not pay twice for Distributed Utility Planning ACE deferral costs, while preserving the opportunity for the Board to review the appropriateness of the Distributed Utility Planning ACE deferral costs for recovery in a rate case.

Therefore, the formula for determining the change in the balance in the Distributed Utility Planning ACE deferral account that is used on page 3 of schedule 8 of both exh. DPS-L&A-11 and exh. DPS-L&A-12 (unamortized monthly balance = prior month's unamortized monthly balance + Distributed Utility Planning ACE amounts due to new installs – current month's amortization) should be adjusted to remove the amounts shown under the column labeled "Installs." Instead, each monthly balance should be the previous monthly balance less the current month's amortization. When this simple mathematical calculation is performed, the Distributed Utility Planning ACE deferral account's 13-month average balance for Rate Year 1 is \$109,373, and the Distributed Utility Planning ACE amount included in CVPS's rate base in Rate Year 1 should be reduced by \$27,418.¹⁶⁹

In addition, the DPS took the balance in the deferral account at the start of Rate Year 2 and divided it by 24 to determine the amount of monthly amortization in Rate Year 2. This is also incorrect. Once the monthly amortization is determined for the deferral account, it should remain constant (at \$6,076 per month) until the balance in the deferral account is eliminated.

167. Gibson reb. pf. 11/15/04 at 18.

168. Tr. 11/4/04 at 86–87 (DeRonne).

169. \$136,791 – \$109,373. The \$136,791 was the 13-month average deferral account balance included in CVPS's original cost-of-service filing for Rate Year 1 in these dockets, not the deferral account balance resulting from the revised calculations CVPS submitted in its rebuttal testimony.

Using the unamortized balance in the deferral account as of the start of Rate Year 2, and the same formula for calculating each month's unamortized balance, the Distributed Utility Planning ACE deferral account's 13-month average balance in Rate Year 2 is \$36,458, and the Distributed Utility Planning ACE amount included in CVPS's rate base in Rate Year 2 should be reduced by \$128,091.¹⁷⁰

In each rate year, the total amortization expense is \$72,915 (\$6,076 *12 months). Compared to CVPS's original cost-of-service filing, this represents a reduction to Distributed Utility Planning ACE amortization expense in Rate Year 1 of \$18,279, and a reduction to Distributed Utility Planning ACE amortization expense in Rate Year 2 of \$36,784.

VI. COST OF SERVICE

A. Power Costs

Findings

146. CVPS receives the bulk of its power, both capacity and energy, from Vermont Yankee and the Hydro Québec Joint Owners Contract ("Hydro-Québec"). These two sources provide a total of about 320 MW of capacity and a projected 2.12 million MWh of energy in Rate Year 1 and 2.28 million MWh of energy in Rate Year 2. Watts pf. at 4.

147. CVPS owns or purchases energy produced by hydro facilities in Vermont and New Hampshire which exceeds 250,000 MWh in an average year, receives about 150,000 MWh annually (on average) through its ownership of the Millstone 3 nuclear plant, and owns or has entitlements in other generation sources that produce about 125,000 MWh annually for CVPS. Watts pf. at 4.

148. CVPS is entitled to, and committed to, purchase more energy from its power supply resources than it currently needs to meet its own expected demand requirements in most hours of the year, except for time periods when Vermont Yankee is not generating. CVPS's resources can deliver up to 235 MW around-the-clock and meet a peak load capacity of 415 MW. CVPS's load

170. \$164,549 – \$36,458. The \$164,549 was the 13-month average deferral account balance included in CVPS's original cost-of-service filing for Rate Year 2 in these dockets, not the deferral account balance resulting from the revised calculations CVPS submitted in its rebuttal testimony.

averages 275 MW, ranging from approximately 205 MW to 360 MW, depending upon the time of day and year. Watts pf. at 5.

149. CVPS sells excess power back through the New England wholesale market and through bilateral contracts. This occurs in most hours of the year. Watts pf. at 6; Lamont pf. at 2.

150. Since CVPS is a net seller on the market, its revenues are directly affected by the market price for power. Recent increases in the market price of power have allowed CVPS to sell back its excess power at a higher price. Watts pf. at 9; Lamont pf. at 2–3.

151. The Connecticut Valley Electric Company sale (described in part VI.B of this Order) reduced CVPS's energy demand requirements by about 130,000 MWh. Watts pf. at 8.

The Power Cost Stipulation

152. CVPS and the Department entered into an agreement resolving most power cost issues.

153. The Net Power Costs (Purchased Power and Production Fuel) for Rate Year 1 are \$128.389 million. Of this, Purchased Power is \$124.863 million and Production Fuel is \$3.526 million. For Rate Year 2, the Net Power Costs are \$124.777 million, consisting of \$121.864 million in Purchased Power and \$2.913 million for Production Fuel. Exh. DPS-CVPS Joint-2.

154. The effective forced outage rate for Vermont Yankee for both rate years is 2.12 percent.¹⁷¹ Exh. DPS-CVPS Joint-2 at 1.

155. The Rate Year 1 Purchased Power Costs reflected in finding 153 include the following amounts as expenses:

2004 Vermont Yankee Fire Outage	\$835,900
Small Power Provider Savings	(\$373,500)
CY/YA ¹⁷² Incremental Decommissioning	\$2,345,200

171. The forced outage rate calculates the typical period in which a generating facility does not generate power or generates only at reduced power. During these periods, the power cost calculations assume the reduced power output and/or different mix of resource use and the potential need to purchase replacement power to service customer load. Planned outages, such as the Vermont Yankee refueling outage, are generally excluded from the calculation.

172. Connecticut Yankee and Yankee Atomic.

Exh. DPS-CVPS-Joint-2 at 1.¹⁷³

156. Transmission by Others includes charges CVPS incurs for general use of the region's Pooled Transmission Facilities and VELCO's transmission system, as well as other specific charges for facilities CVPS uses. Watts pf. at 22.

157. Transmission by Others costs are \$13.562 million in Rate Year 1 and \$14.895 million in Rate Year 2, of which \$9.202 million and \$10.604 million, respectively, are VELCO costs. Exh. DPS-CVPS Joint-2 at 2.

158. The Transmission by Others figures reflect the favorable impact of the Highgate convertor station receiving phased-in Pooled Transmission Facilities treatment beginning February 2005. This reduced costs by \$45,000 in Rate Year 1 and \$575,000 in Rate Year 2. Exh. DPS-CVPS Joint-2 at 2.

2002 Vermont Yankee Mid-Cycle Outage

159. Findings 29–35, above, are incorporated by reference.

Nuclear Decommissioning Costs

160. Findings 43–49, above, are incorporated by reference.

Docket 6270 Savings

161. Findings 50–54, above, are incorporated by reference.

2004 Vermont Yankee Fire Outage

162. Findings 39–42, above, are incorporated by reference.

173. As discussed below, the parties ask the Board to decide whether these amounts should be expensed in Rate Year 1 or deferred and then amortized in Rate Year 2 (or some combination of the two). Exh. DPS-CVPS-Joint-2; exh. CVPS-CJF-15. *See also*, findings 160–162.

Discussion

Power costs represent the largest component of CVPS's cost-of-service. Purchased power alone — largely from Vermont Yankee and Hydro-Québec — is nearly half of CVPS's cost-of-service. Thus, CVPS's management of its power supply costs can significantly impact the overall rate levels.

At the present time, CVPS has entitlements for more power than it needs. In most hours of the day, CVPS has excess energy and capacity, which it sells through bilateral contracts with other utilities or through the New England wholesale market. From a ratemaking perspective, the Board has traditionally allowed CVPS to include the cost of all of its power resources in the power costs, even if those were not necessary to serve Vermont load. To balance these charges, we have consistently included the revenues from these wholesale arrangements (adjusted to reflect the market prices expected to prevail in the adjusted test year). This regulatory treatment means that Vermont ratepayers benefit from the sale of the excess power, particularly if the market price for power in these wholesale transactions exceeds the costs of the power.¹⁷⁴ Moreover, energy efficiency savings also produce a benefit for Vermont ratepayers as they allow CVPS to sell more power than the Company otherwise would have. Significantly for the present case, wholesale power costs have risen well above the level in the 1990s and the test year. The effect is that a company like CVPS, which has power available for sale, will be earning more from wholesale transactions than in prior years and thus needing less revenue from its retail customers.

In this case, the Department and CVPS have largely agreed on the power costs for both rate years. They embodied this consensus in a Power Cost Agreement.¹⁷⁵ In the Power Cost Agreement, these parties specify the appropriate costs for Purchased Power, Production Fuel, and Transmission by Others for each of Rate Years 1 and 2. The Agreement did not resolve all disputes, however. Instead, the parties deferred several specific issues to the Board for resolution. We address each of these below.

174. If the resale value of the power is below its cost, ratepayers fare less well and end up paying extra costs for power that is not needed to serve them. Even so, the net cost to retail customers would be less than if purchased power costs were considered and power sales revenues were not.

175. Exh. DPS-CVPS-Joint-2.

2002 Vermont Yankee Mid-Cycle Outage

During 2002, Vermont Yankee experienced an unanticipated shutdown to replace defective fuel rods. The fuel rods had developed small leaks and were releasing radiation into the core. Vermont Yankee had identified the problem earlier in the year and, after investigation, decided that the best option was to shutdown the facility to remedy the problem (rather than waiting for the scheduled refueling outage in October of that year).

The Mid-Cycle Outage lasted 12 days. The loss of the Vermont Yankee power forced CVPS to acquire replacement power. CVPS also incurred other expenses for Vermont Yankee's operation and maintenance expenses to remedy the problem and replace the defective fuel. At CVPS's request, we issued an accounting order on July 18, 2002, authorizing CVPS to defer these incremental costs. Subsequently, Vermont Yankee received partial compensation from the fuel vendor; CVPS reduced the deferral amount based upon its share of these recoveries. CVPS now seeks recovery of the remaining deferral amount.

The Department generally does not oppose the recovery of the amounts deferred from the 2002 Mid-Cycle Outage. However, the Department points out that during the rest of 2002, Vermont Yankee had an output greater than the Board had assumed in setting CVPS's rates in 2001 (Dockets 6120/6460). According to the Department, the parties had used a 4 percent forced outage rate in formulating the stipulation in that case; Vermont Yankee's actual performance was much better during 2002, particularly after factoring out the Mid-Cycle Outage for which CVPS was already expected to receive compensation.¹⁷⁶ The Department takes the position that in determining the appropriate amount that CVPS can recover, we should assess the financial harm to CVPS of Vermont Yankee's under-performance and not limit our ruling to the time period of the Mid-Cycle Outage.¹⁷⁷

CVPS argues first that the Department's proposed adjustment has no impact on rates as a downward adjustment to the Mid-Cycle Outage regulatory asset would lead to a similar

176. The parties have agreed that the period in which Vermont Yankee was not generating power due to the Mid-Cycle Outage should not be considered in calculating the forced outage rate on a going-forward basis. The reason for this agreement is that CVPS is being compensated already for the outage through the deferral of incremental costs which CVPS will begin amortizing as part of these proceedings.

177. DPS Brief at 26–27.

downward adjustment to overearnings in 2002.¹⁷⁸ In addition, CVPS argues that the Department's proposal is not consistent with the terms of the Mid-Cycle Outage Accounting Order, which was limited to the period of the outage.¹⁷⁹ Finally, CVPS states that, if the Board makes an adjustment, the proper amount is \$403,000, not the amount the Department had previously recommended.¹⁸⁰

Vermont Yankee is a favorably-priced source of power for CVPS; when it is not operating, CVPS must purchase replacement power (or use its excess resources, losing the resale revenues), often at higher prices. To reflect this in ratemaking, we assume that Vermont Yankee will be unavailable a certain percentage of the time and that other sources will provide the power during that time. We embody these assumptions in a forced outage rate, which is typically derived based upon the recent operating performance of Vermont Yankee. For example, in this proceeding, the Department and CVPS have agreed that the rates we set here should be based upon a 2.12 percent forced outage rate.¹⁸¹ Of course, actual performance does not necessarily reflect these assumptions. If Vermont Yankee's operating performance matches the assumptions incorporated into the forced outage rate, CVPS benefits in the form of lower power costs than we had assumed. Conversely, CVPS bears the risk that Vermont Yankee produces less power than assumed and its earnings may be adversely affected. Typically, we do not attempt to recapture these gains or compensate CVPS for its losses (the performance would be incorporated into the forced outage rate for the next rate case).

CVPS's deferral of the costs associated with the 2002 Mid-Cycle Outage alters this normal allocation of risk. Instead of CVPS incurring the higher costs that arise because Vermont Yankee performed less well than expected, the deferral assigns these costs to CVPS's ratepayers. In this situation, we conclude that CVPS should offset the deferral amount by the better-than-average performance to mitigate the effect of the shifting of risk allocation. Both the Department and CVPS agree that the value of the gain is \$403,000 and we accept that figure.

We find the terms of the accounting order in which we authorized the deferral do not

178. CVPS Brief at 109.

179. Page reb. pf. at 24.

180. The Department agreed with the \$403,000 figure. Lamont reb. pf. at 5.

181. Exh. DPS-CVPS-Joint-2 at 1.

require a different result. First, as we have explained elsewhere in this Order,¹⁸² accounting orders do not dictate ratemaking treatment. The determination of the appropriate amount that CVPS can recover in rates was deferred to this proceeding. Second, to the extent that CVPS is now attempting to use accounting orders as substitutes for fuel adjustment clauses,¹⁸³ fairness dictates that the adjustment cannot be one-way.¹⁸⁴ Yet the effect of CVPS's proposal is to obtain recovery for the part of the year when Vermont Yankee's performance was worse than expected, while ignoring the superior performance in the surrounding period.

We agree with CVPS that our ruling on this issue may not have any impact on the ultimate rates. CVPS excluded the deferred amount from its overearnings calculation for 2002. As a result of our decision, CVPS will reduce the deferral amount to be recovered through amortizations starting in Rate Year 1, but it will also need to adjust the amount of the deferral excluded from the 2002 overearnings calculation. The evidence suggests that these two amounts will offset.

Expensing of VEPPI Cost Mitigation, Incremental Decommissioning Costs, and 2004 Vermont Yankee Fire Outage

In Section IV, above, we describe CVPS's various regulatory assets and liabilities. In its original filing, CVPS proposed to amortize most of these deferrals over three years beginning in Rate Year 2. The Company also included the same amortizations (or, in the case of the 2004 Mid-Cycle Outage, the full expense) in Rate Year 1. CVPS characterized these as illustrative, *pro forma* adjustments. In its later filings and brief, CVPS removed the Rate Year 1 amortizations for most of these accounts. The Department supports commencing the amortization of all of these accounts in Rate Year 1, with corresponding adjustments to Rate Year 2 to reflect the amortization that occurred in Rate Year 1. Above, we adopt the Department's recommendation, for the reason we explained.

182. See finding 4, above.

183. See discussion on page 55, above.

184. As we discuss above, such use of accounting orders is inappropriate. Power plant outages generally are not extraordinary; in fact, the reason we include a forced outage rate is because we expect power plants to be out-of-service for specific reasons that cannot be anticipated.

In the Power Cost Agreement, CVPS and the Department identify three particular cost items that these parties agree should be either treated as an expense in Rate Year 1 or deferred with amortizations to begin in Rate Year 2. The three items are as follows:

- 2004 Vermont Yankee Fire Outage. In June, 2004, Vermont Yankee experienced an outage due to a busbar fault and subsequent transformer fire. CVPS incurred \$836,000 in incremental replacement power costs as a result. The Board authorized the deferral of the added costs of the 2004 Fire Outage in an Interim Accounting Order dated July 12, 2004, although we subsequently stayed portions of that Order and deferred a final accounting order to this proceeding.¹⁸⁵ CVPS also reflected the costs of the 2004 Fire Outage in Rate Year 1 as expenses.¹⁸⁶
- VEPPI Cost Mitigation. CVPS receives credits from VEPPI as a result of agreements approved by the Board in Docket 6270. CVPS proposes to amortize these credits, as a reduction to purchased power costs. A portion of the credits are incremental in Rate Year 1 and the Department seeks to expense them instead of deferring and amortizing the credits.
- Incremental Decommissioning Expenses. CVPS will need to pay incremental decommissioning expense associated with Maine Yankee, Yankee Atomic, and Connecticut Yankee during Rate Year 1. The Board authorized CVPS to defer these incremental decommissioning expenses in an Accounting Order dated October 29, 2003.¹⁸⁷

In the Power Cost Agreement, the parties reflected each of these items as expenses in Rate Year 1, but continued to request that the Board decide whether to expense the item in that Rate Year or defer and amortize the costs beginning in Rate Year 2.¹⁸⁸ The Department takes the position that CVPS should either reflect the costs as expenses in Rate Year 1 or defer them for recovery starting in Rate Year 2, but not both. The Department asks us to adopt the former approach.¹⁸⁹ CVPS favors deferring these costs and amortizing them beginning in Rate Year 2. CVPS asserts that the costs for the decommissioning and VEPPI cost mitigation were erroneously included in Rate Year 1 as an expense.¹⁹⁰ CVPS takes the position that absent such

185. Gibson pf. at 40.

186. In its Reply Brief, CVPS suggests that these costs are not reflected in the rates now in effect for Rate Year 1 and that they are not reflected on the Company's books. CVPS Reply Brief at 114. This is true, but misses the point. CVPS *did* include the 2004 Fire Outage costs as expenses in its Rate Year 1 cost of service.

187. Gibson pf. at 41; Page pf. at 13.

188. Exh. DPS-CVPS-Joint 2 at 1; exh CVPS-CJF-15 at 1.

189. Tr. 2/18/05 at 77 (Schultz).

190. Tr. 2/18/05 at 39 (Frankiewicz).

treatment, CVPS will have no ability to recover them. According to CVPS, it has a revenue deficiency in Rate Year 1; expenses added in Rate Year 1 exacerbate that deficiency and deny CVPS any opportunity to recover these deferred costs.

We conclude that, particularly in light of the fact that we find CVPS to have excess earnings in Rate Year 1 — even after reflection of these three items as expenses — it is reasonable to incorporate them as expenses now rather than create another set of deferrals that will be charged to future ratepayers (or, in the case of the VEPPI mitigation, serve as a credit). In the case of the 2004 Vermont Yankee Fire expense, it is undisputed that the actual expense occurred in Rate Year 1.

As to CVPS's claim that deferral and amortization is necessary in order to allow CVPS to recover these costs (or ratepayers to receive the benefit of the VEPPI credit), we disagree. In this Order, we find that CVPS must reduce its rates in Rate Year 1. Inclusion of these cost items will have the effect of making the reduction smaller. Moreover, by including them in our cost analysis, we have allowed CVPS to recover them.¹⁹¹

Our decision today means that the accounting order associated with each of these expenses (and credit) will terminate. The full rate recovery in Rate Year 1 makes such treatment moot.¹⁹²

It is possible that CVPS will be reimbursed for some or all of the expenses of the 2004 Vermont Yankee Fire Outage. As part of a Memorandum of Understanding with the Department in Docket 6812, Entergy has established a Ratepayer Protection Plan, under which Entergy will reimburse CVPS and GMP for replacement power costs (and lost resale revenues) arising from outages at Vermont Yankee caused by the power uprate authorized in that Docket and the plant modifications that enabled that power increase. CVPS has requested that the Board determine whether the 2004 Fire Outage was uprate-related and thus whether Entergy is obligated to provide reimbursement.¹⁹³ The Department raised concerns during the instant cases that, if CVPS is successful, the recovery may not be passed on to ratepayers.

191. CVPS's argument would have had more validity if, in fact, we had found a revenue deficiency in Rate Year 1.

192. Frankiewicz reb. pf. at 10–11.

193. The Board has opened Docket 6812-A to consider CVPS's petition.

We expect that CVPS will ensure that any recovery from Entergy will be returned to ratepayers. The purpose of the Ratepayer Protection Plan was to ensure that ratepayers were not exposed to higher costs due to uprate-related outages at Vermont Yankee. Failure to return this money to ratepayers would defeat this purpose, given that in today's Order we are allowing CVPS to recover in rates the costs of the 2004 Vermont Yankee Fire Outage. Thus, we direct that, if CVPS receives full or partial reimbursement from Entergy, the Company will book the amount received as a regulatory liability for return to ratepayers in the next rate proceeding.

Levelization of Decommissioning Costs

The Department raises concerns about the timing of the decommissioning expenses for Connecticut Yankee, Maine Yankee, and Yankee Atomic (jointly referred to as the "Yankee" plants). Because of increased costs for decommissioning these three facilities, CVPS reflects high costs in both Rate Years 1 and 2. After that time, CVPS's expected decommissioning obligation is smaller (assuming current estimates remain unchanged). As a result, the Department is concerned that reflection of the actual Yankee decommissioning expenses for Rate Years 1 and 2 will lead to "significant overpayment by ratepayers in years subsequent to Rate Year 2."¹⁹⁴ The Department's proposed remedy is to levelize the decommissioning expenses over the period from April 1, 2004, through 2010.¹⁹⁵

CVPS opposes levelization of the Yankee decommissioning expense. CVPS takes the position that, if we levelize the decommissioning expense, CVPS will recover significantly less than it must pay during the early years, which adversely affects its cash flow and denies the Company an opportunity to earn its allowed return.¹⁹⁶ CVPS also notes that levelization would increase the regulatory asset balances and impose a cash flow constraint on the Company.¹⁹⁷

The evidence demonstrates that CVPS will have to pay the actual Yankee decommissioning costs, not the levelized rate. If we adopted the Department's proposal, we would thus embed in CVPS's rates a cost component that we know is below the Company's

194. DPS Brief at 46.

195. Schultz and DeRonne pf. at 38–39.

196. CVPS Reply Brief at 155.

197. CVPS Reply Brief at 158.

actual costs. We are not persuaded that, considering the magnitude of the change in decommissioning costs after this year (which is small in relation to CVPS's overall cost of service)¹⁹⁸ and the possibility that those costs will change again in the future, such a course is reasonable.

Moreover, the Department's proposal would have future ratepayers pay the costs for decommissioning that are associated with expenses that are arising today. As a general rule, the Board's policy has been that current ratepayers should pay for current costs. Using this rationale, we agree with CVPS that current ratepayers should be paying for increased decommissioning costs.¹⁹⁹

We are concerned, however, that the decommissioning costs that we use for setting rates are in excess of those that will apply after Rate Year 2. Therefore, beginning April 1, 2006, we will require CVPS to book and defer the difference between the decommissioning cost for Rate Year 2 on which we set rates and the actual decommissioning cost payments.²⁰⁰ CVPS will amortize the balance in this account in its next rate case.

Treatment of Decommissioning Costs

In its cost-of-service filings, CVPS includes the decommissioning costs for Connecticut Yankee, Yankee Atomic, and Maine Yankee as part of purchased power expense. According to the Department, none of these plants is operating, so the costs are not actually power costs.²⁰¹ Therefore, the Department asks that we classify these costs as non-fuel production. CVPS maintains that the FERC chart of accounts requires these costs to be recorded as purchased power expense.²⁰²

198. The effect of the levelization is \$718,826 in Rate Year 1 and \$1,520,678 in Rate Year 2. Exh. DPS-L&A-11 at schedule 10.

199. Tr. 2/18/05 at 53 (Frankiewicz).

200. It is our assumption that this will result in a regulatory liability, i.e., the costs in rates will exceed decommissioning costs. This is consistent with the current FERC rate schedules under which CVPS pays these costs. If the Yankee decommissioning costs increase from levels now projected for 2006 and beyond, we require CVPS to notify the Board.

201. DPS Brief at 46.

202. Tr. 2/18/05 at 50 (Frankiewicz).

The parties agreed that the outcome of this dispute has virtually no monetary impact;²⁰³ there is no significance for rate setting if the decommissioning costs are recorded in purchased power or in non-fuel production. Given this fact, it appears that the only significance is whether FERC accounting will be the same as Board accounting. CVPS's proposal would align our accounting with FERC, whereas the Department's would not.²⁰⁴ For this reason, we adopt CVPS's recommendation to continue recording the decommissioning costs in purchased power accounts.

B. Sale of Connecticut Valley Electric Company

Findings

163. CVPS sold the assets of its New Hampshire subsidiary, Connecticut Valley Electric Company ("CVEC"), to Public Service Company of New Hampshire ("PSNH") effective January 1, 2004. Gibson pf. at 2, 7.

The Sale Transaction

164. CVPS sold the assets of CVEC at the sum of book value plus \$21 million. Gibson pf. at 19.

165. The \$21 million payment was intended to cover stranded costs associated with CVPS's provision of wholesale power to CVEC. The intent of the payment was to hold CVPS's ratepayers harmless from the effects of the termination of the CVEC power arrangement that otherwise would have meant a shift of costs to Vermont retail ratepayers. Gibson pf. at 19; Deehan reb. pf. at 12; exh. DPS-37.

166. As part of the transaction, CVEC and CVPS allowed the wholesale power agreement between them to end. PSNH also received open access transmission service from VELCO and CVPS. Deehan reb. pf. at 12.

167. The \$21 million represented the parties' estimate of the loss to CVPS from termination

203. Tr. 2/18/05 at 50 (Frankiewicz). Mr. Frankiewicz suggested that there may be a minor working capital difference.

204. CVPS Reply Brief at 155, citing exh. CJF-14 and tr. 2/18/05 at 76 (Schultz).

of the power contract. At the time of closing, the estimated loss became \$14.351 million, resulting in a \$6.649 million gain for CVPS which the Company recorded on January 1, 2004.²⁰⁵ Schultz and DeRonne pf. at 65.

168. On January 1, 2004, CVPS recorded the estimated loss of \$14.351 million and a future liability for power costs through 2016. CVPS proposed to amortize the liability over 12 years as a reduction to the actual power cost obligation recorded and paid each year. Schultz and DeRonne pf. at 64; tr. 1/12/05 at 46–47 (Gibson).

169. The sale of CVEC eliminated the risk that significant power costs incurred to serve CVEC customers would be shifted to CVPS's customers as a result of restructuring in New Hampshire. Deehan reb. pf. at 12–13; Gibson pf. at 7, 18–19.

Events Prior to the Sale

170. On February 28, 1997, the New Hampshire Public Utility Commission ("NHPUC") adopted a restructuring plan that found that CVEC should terminate its wholesale requirements power agreement with CVPS and ruled that no above-market (or stranded costs) recovery would be allowed in CVEC's rates. Deehan reb. pf. at 9.

171. Implementation of the NHPUC's restructuring order would have had a material adverse impact on the Company. It also would have required CVPS to record a loss contingency at that time of \$75 million under SFAS 5. Deehan reb. pf. at 9, 13; exhs. CVPS-WJD-4, CVPS-8, CVPS-9, and CVPS-10.

172. CVPS challenged the NHPUC's restructuring order in federal court. After years of litigation, the U.S. District Court permanently enjoined the NHPUC's restructuring plan, determining that until FERC established stranded cost compensation and the wholesale arrangement was legally terminated, the restructuring plan could not proceed. Deehan reb. pf. at 9.

173. CVPS also participated in litigation at FERC concerning the NHPUC's Order. CVPS charged all of the costs of the FERC litigation to CVEC. Frankiewicz reb. pf. at 23.

174. As a result of the federal litigation (generally referred to as the "*Patch*" case), the loss

205. CVPS states that the present value of these expected credits is \$6.2 million. Deehan reb. pf. at 14.

contingency estimated at \$75 million in 1997 dropped to \$33 million in 2001 and \$14.6 million at the time of the sale on January 1, 2004. Deehan reb. pf. at 9–10.

Cost-of-Service Effects

175. CVPS will flow the stranded cost payment from PSNH back to Vermont retail customers in the form of credits. Deehan reb. pf. at 14; exh CVPS-WJD-5.²⁰⁶

176. Prior to the sale, CVEC compensated CVPS for costs associated with operations, maintenance, and infrastructure services provided by CVPS to CVEC through direct assignment of costs, to the extent that these costs could be identified. In addition, CVPS entered into a service contract with CVEC to allocate a share of other costs, such as infrastructure costs, that could not be directly assigned. Tr. 11/2/04 at 144–145 (Gibson); tr. 11/3/04 at 85–86 (Gibson).

177. As part of the sale, CVPS terminated the service contract with CVEC. Schultz and DeRonne pf. at 70.

178. The sale of CVEC causes a loss of some economies of scale and scope that CVPS enjoyed through the ownership of CVEC. Gibson pf. at 20.

179. CVPS took some steps to mitigate cost impacts of the CVEC sale, such as closing the Ascutney Service Center and the transfer of employees who worked in CVEC's service territory. Gibson pf. at 21.

180. Only a few employees left CVPS as a result of the CVEC transfer. Schultz and DeRonne pf. at 64.

181. CVPS cannot readily reduce many of the fixed costs that had been allocated to CVEC. These include costs such as the computer network necessary to meet customer service obligations. These general operating costs are shared by the consolidated entity, so that with the sale of CVEC, the remaining customers of CVPS must pick up all of the costs. Gibson pf. at 20; Schultz and DeRonne pf. at 64.

182. Largely because of the CVEC sale, the allocation of costs to wholesale services dropped

206. CVPS reflects this payment as a \$1,195,920 credit to power costs in each year. Exhs. CVPS-CAW-A2 and CVPS-CAW-B2. This credit does not include return of the \$6.6 million gain, which CVPS proposed to pass on to shareholders.

from 4.73 percent to 1.1 percent. Tr. 11/2/04 at 17 (Frankiewicz).

183. The change in the allocation of wholesale costs means that the sale has the effect of transferring approximately \$1.846 million annually in costs to CVPS and its Vermont retail ratepayers. These cost increases would not have occurred if CVEC had not been sold. Schultz and DeRonne pf. at 63; tr. 11/2/04 at 145–147 (Gibson); tr. 1/11/05 at 99–100 (Frankiewicz).

184. The power costs that are stranded and are reallocated through the wholesale allocation factors comprise Purchased Power, Production, Transmission by Others, Highgate, and Other Operating Expenses and Return. Tr. 1/11/05 at 103 (Frankiewicz)

185. The termination of the service contract, by which direct costs as well as cost allocations for general corporate overhead were assigned to CVEC, results in the transfer of \$1.9 million in Rate Year 1, and a slightly larger increase in Rate Year 2, to Vermont customers. Tr. 11/2/04 at 145–147 (Gibson); Deehan reb. pf. at 14–15.

186. Most of the costs associated with the service contract are for administrative and general expenses. Other costs are for production, transmission, distribution, customer accounting, and customer service. Exh. CVPS-55.

187. In Rate Year 1, \$1.327 million of the service contract costs are administrative and general. In Rate Year 2, this figure is \$1.405 million. After assigning a proportionate share of payroll taxes, these amounts increase to \$1.376 million and \$1.456 million, respectively.²⁰⁷ Collectively, the other categories of expenses allocated under the service contract total to \$0.536 million in Rate Year 1 and \$0.558 million in Rate Year 2. Exhs. CVPS-CJF-2 and CVPS-CJF-6; exh. CVPS-55.

207. In its cost-of-service filings, CVPS did not break out the payroll tax between the administrative and general expense category and other categories. On exh. CVPS-55 (which shows the test year figures analogous to the Rate Year 1 and 2 amounts), CVPS showed that 62.5 percent of its payroll expense under the service contract applied to administrative and general costs. We have allocated the payroll expenses in each rate year using the same percentages. Thus, in rate year 1, we have added 62.5 percent of the \$78,000 in taxes — \$48,750 — to the administrative and general category to reflect the tax effects of the allocation.

Discussion

For over 70 years, CVPS owned and operated a New Hampshire retail subsidiary, CVEC, as an integrated part of its utility operation. CVPS acquired power supply resources beyond those necessary to serve its native Vermont load in order to provide power for the CVEC load, with the costs charged to the New Hampshire customers. CVEC also paid CVPS for other elements of the retail service. To the extent that costs were directly attributable to CVEC, CVPS assigned those costs to its subsidiary. For joint and common costs that could not be directly assigned, CVPS and CVEC entered into a service contract under which CVPS was allocated a share of those costs.²⁰⁸ Through the service contract, portions of costs such as the billing system could be passed on to CVEC.

These cost allocation methodologies ensured that CVEC and its customers paid for the direct costs that CVPS incurred to serve them. In addition, CVPS could take advantage of the economies of scale arising from the larger entity. This had the effect of reducing the cost of service for Vermont ratepayers. Traditional ratemaking methodologies led to even further reductions in costs for CVPS's Vermont customers since CVPS's overall cost of service is adjusted by allocating a portion of its costs to wholesale services. Due to the size of the CVEC commitment, the wholesale cost allocator was 4.73 percent.²⁰⁹

In 1996, the New Hampshire Public Utilities Commission ("NHPUC") began steps towards electric restructuring.²¹⁰ On February 28, 1997, the NHPUC adopted a restructuring plan that found that CVEC should terminate its wholesale requirements power agreement with CVPS. Significantly, the NHPUC also specified that no above-market cost recovery would be allowed in CVEC's retail rates. The NHPUC also ruled that CVEC was imprudent for not terminating its FERC-authorized power contract with CVPS to take advantage of lower market costs. This decision would have required CVPS to record a significant loss contingency under SFAS 5, then-estimated to be \$75 million.²¹¹

CVPS challenged the NHPUC's ruling in federal court in what became referred to as the

208. Tr. 11/2/04 at 144–145 (Gibson); tr. 11/3/04 at 85–86 (Gibson).

209. Schultz and DeRonne reb. pf. at 28.

210. Deehan reb. pf. at 9.

211. Deehan reb. pf. at 9; Schultz and DeRonne pf. at 59.

Patch case. The U.S. District Court upheld FERC's exclusive jurisdiction over the wholesale power arrangement and enjoined the NHPUC from proceeding until FERC had established stranded cost compensation and terminated the wholesale power arrangement.²¹² At the same time, CVPS initiated a proceeding at FERC to establish an exit fee under FERC's open access transmission regulations. An Administrative Law Judge issued a ruling that was generally favorable to CVPS.²¹³

At the same time it pursued litigation, CVPS also conducted negotiations with New Hampshire parties to try to resolve the dispute. These ultimately led to an agreement to sell CVEC to PSNH. CVPS pursued the sale in order to mitigate harm that was being imposed on the Company by the NHPUC's policies.²¹⁴

The sale to CVEC was a three-party arrangement between CVEC, CVPS, and PSNH. CVPS sold the assets of CVEC for book value. CVPS agreed to terminate the wholesale power sale arrangement with CVEC. In exchange, PSNH agreed to pay CVPS \$21 million. This figure represented the parties' assessment of the stranded costs that CVPS would experience from having incurred the long-term arrangements to serve the CVEC load that would now be PSNH's responsibility. As such, it was based upon the parties' market price forecasts. The parties closed the transactions on January 1, 2004. By the time of the closing, long-term market price forecasts had changed, so that the stranded cost estimate had dropped to \$14.351 million.²¹⁵ As a result, CVPS recorded a loss of this amount and a gain of \$6.649 million (which represented the difference between the original estimate and the January 1, 2004, estimate) on the closing date.²¹⁶

CVPS states that the \$21 million payment to terminate the power contract was designed to ensure that, over time, the loss of CVEC loads would not result in increased power costs being recovered from CVPS customers.²¹⁷ CVPS planned to amortize the stranded cost payment

212. Schultz and DeRonne pf. at 59; Deehan reb. pf. at 9.

213. Deehan reb. pf. at 10.

214. Gibson pf. at 7.

215. The \$14 million stranded cost estimate could increase over time if market prices fall from current levels, thus reducing CVPS's revenues from selling the excess power. Tr. 1/12/05 at 47–49 (Gibson).

216. Schultz and DeRonne pf. at 64–65.

217. Gibson pf. at 19.

(offset by the \$6.649 million gain) over 12 years as a reduction to the actual power cost obligation recorded and paid each year.²¹⁸ CVPS also observes that, given the expected cost and market value of the power, in combination with the stranded cost payment received, CVPS expects that its Vermont customers will receive net power cost credits.²¹⁹ CVPS calculates the net present value of those expected credits as of January 2005 is \$6.2 million.²²⁰

The Department challenges CVPS's proposed ratemaking treatment. From a broad perspective, the Department points out that CVPS booked a \$6.649 million gain on January 1, 2004, which inured to the benefit of shareholders. At the same time, CVPS has proposed to increase costs by \$1.9 million in Rate Year 1 and \$2.0 million in Rate Year 2 due to elimination of the service contract and an estimated \$1.8 million each year due to the change in wholesale allocation factors. In addition, according to the Department, the service to Vermont ratepayers is the same today as it was prior to the sale, yet as a result of the CVEC sale, ratepayers incur added costs.

The Department proposes two particular adjustments to make the transaction more fair. First, the Department objects to flowing back the costs of the service contract to CVPS. The Department recommends reversing CVPS's reflection of the elimination of the service contract. Second, the Department argues that we should flow back the \$6.649 million gain from the termination of the power contract to ratepayers over a three-year period. According to the Department, this treatment will offset the additional costs that Vermont ratepayers would otherwise absorb as a result of the sale of CVEC and the change in wholesale cost allocators that ensued.²²¹

AARP supports the Department's recommendations. AARP argues that the testimony "burst the bubble" of the rebuttable presumption that CVPS was prudent in negotiating the terms of the CVEC sale. AARP asserts that, in the absence of the rebuttable presumption, CVPS has not presented sufficient evidence to justify any increased cost to Vermont ratepayers as a result of

218. CVPS included a reduction of \$1,195,920 in each of Rate Years 1 and 2 to incorporate this amortization. Exhs. CVPS-CAW-A2 and CVPS-CAW-B2.

219. Deehan reb. pf. at 14.

220. Deehan reb. pf. at 14.

221. Schultz and DeRonne reb. pf. at 66.

the CVEC sale.

CVPS opposes the Department's adjustments. CVPS states that it has recorded all of the costs of the transaction above the line and asks that the Board allow recovery for all of them. CVPS also argues that it has proposed no adjustment to its cost of service, other than the \$1.8 million adjustment for the service contract, that sought to recover common costs from Vermont ratepayers.²²² CVPS adds that it has taken actions to pass the gain from the sale on to customers; the Company points to the accounting order that we issued on February 18, 2005, under which the Company will defer overearnings in 2004 (computed under the Company's methodology) to 2005. CVPS says that this assures that all excess earnings — caused largely by the gain on the CVEC transaction — can be reflected to the benefit of customers at the start of new rates on April 1, 2005. CVPS argues that this action, coupled with the annual reversal of the \$14.4 million SFAS No. 5 loss contingency, assures that customers benefit from the excess net profits of the transaction.²²³

Turning first to AARP's arguments, we find no basis to conclude that CVPS may have been imprudent in negotiating the CVEC sale. To the contrary, the record shows that CVPS's aggressive pursuit of litigation in both federal court and at FERC and the ultimate sale to CVEC avoided potentially negative consequences to the Company and its Vermont ratepayers. Had CVPS not sold CVEC and the NHPUC order requiring restructuring was ultimately upheld, the restructuring might have resulted in higher power costs for CVPS and its Vermont ratepayers. CVPS would still have the same power resources, but would no longer receive revenues from the sale of power to CVEC.²²⁴ The evidence shows that the potential magnitude of these costs was large — as of 1997, CVPS estimated that the power resources it had to serve CVEC would, if that sale was no longer available, have been in excess of their market value by approximately \$75

222. CVPS Reply Brief at 191.

223. CVPS Reply Brief at 187–188.

224. Tr. 11/2/04 at 138–139 (Gibson). As we explain above, in rate proceedings, we traditionally do not bar recovery of power purchases and entitlements in excess of what is needed to serve CVPS's load. Instead, we attribute resale revenue to any power in excess of CVPS's actual needs. To the extent that the price of the power CVPS acquired to serve CVEC exceeded the resale value, Vermont ratepayers may have paid the difference. We have also generally allowed such treatment when wholesale transactions are terminated.

million over their remaining life.²²⁵ By the time of the sale agreements, this figure had dropped to \$21 million, for which CVPS received compensation;²²⁶ market price rises subsequent to that time have now reduced the estimated stranded costs to only \$14.4 million. Thus, CVPS's litigation and sale avoided substantial additional power costs to Vermont ratepayers.

The Department's proposed adjustments do not challenge the merits of the sale, but focus on the cost shifts that arise from the sale. The first cost shift arises from the termination of the service contract, whereby CVPS allocated certain costs to CVEC. In large part, we do not accept the Department's recommendation. Over 60 percent of the costs allocated under the contract are general overhead expenses (or associated payroll taxes). For example, portions of officers' salaries were assigned through this mechanism. These expenses are not readily avoidable; after the CVEC sale, most of these costs remain unchanged.

Other costs allocated under the service contract, however, are associated with specific functions that CVPS will no longer provide to CVEC. These include allocations for customer accounting and billing, the bulk of which are associated with payroll.²²⁷ Although the Company's billing system does not change with the end of the CVEC contract, CVPS no longer needs the employees that previously provided such support to CVPS. Similarly, production, transmission, and distribution services will no longer be performed. Instead of the full costs of the service contract, we find it reasonable to allow CVPS to recover \$1.376 million in Rate Year 1 and \$1.456 million in Rate Year 2.²²⁸

The second cost shift identified by the Department is the change in the wholesale allocation factor. CVPS asserts that there is no actual change in costs, so the Department's adjustment must be rejected. In a narrow sense, CVPS is correct — the loss of CVEC did not shift costs to CVPS (except for the costs directly assigned or allocated through the service contract). However, it fails to consider the fact that, in addition to these two methods of

225. Deehan reb. pf. at 9–10.

226. This change is attributable to two factors. First, the market price for power has increased, allowing CVPS to resell the power for more and reducing the stranded cost loss. Second, CVPS was able to sell the power at cost for the intervening period, so that the CVEC customers paid a share of the costs.

227. Exh. CVPS-55; exhs. CVPS-CJF-2 and CVPS-CJF-6.

228. See finding 187.

assigning costs to CVPS, the ratemaking methodology we employ also allocates a certain portion of other costs through the wholesale allocation factor. This factor will be directly affected by the large reduction in wholesale power sales to CVEC. The parties could not calculate it precisely, but the financial impact on Vermont ratepayers of this change appears to be approximately \$1.8 million annually.

To compensate ratepayers for these added costs (at least in the short run), the Department proposes to allocate the \$6.6 million gain from the termination of the CVEC power contract, amortized over three years. We find this approach reasonable. The cost shift to Vermont ratepayers from the wholesale allocation factor change is real. As presently structured, CVPS would have Vermont ratepayers absorb the full impact of this change, while simultaneously retaining the full value of the \$6.6 million gain for its shareholders. CVPS has not shown why this allocation of costs and benefits is reasonable.

We recognize that CVPS has deferred some overearnings from 2004, the bulk of which are attributable to the CVEC sale, to 2005.²²⁹ However, this adjustment is for accounting purposes only; it is not revenue that we can consider for ratemaking purposes in 2005. We expect that CVPS's deferral of these earnings will help the Company's financial standing, but it has no bearing on the rates we set today. Similarly, the deferral does not actually return any of the \$6.6 million to ratepayers.

CVPS also states that the Department's approach fails to recognize the stranded cost payments that are being used to benefit ratepayers. Specifically, CVPS will amortize the \$14.4 million over 12 years to offset the stranded power costs. CVPS's ability to secure full compensation for these stranded costs is a positive aspect of the sale as structured. These payments, however, do not provide ratepayers with an additional benefit as CVPS suggests; rather, they simply make ratepayers neutral as to the power costs that will be returned to CVPS as a result of the termination of the wholesale arrangement.

Overall, we find that the proposed amortization of the \$6.6 million over three years is reasonable. Both the \$6.6 million gain and the \$1.8 million increase in annual costs result directly from termination of the CVEC power contract. It is appropriate to offset the increased

229. In fact, the \$6.6 million exceeds the deferred overearnings.

power costs by the \$6.6 million gain. We, therefore, adopt the DPS's proposed amortization of the \$6.6 million gain over three years.

C. Regulatory Commission Expense

Findings

188. Findings 170–174 above are incorporated here.

189. CVPS included the half of its costs of litigating the *Patch* case in its calculation of regulatory commission expenses. Schultz and DeRonne pf. at 57–60.

Discussion

Regulatory commission expenses can vary greatly from year to year. For example, over the past five years, they have ranged from \$569,579 to \$1,245,520.²³⁰ Because of this variance, the Board typically establishes the regulatory commission expense for CVPS using an average of the previous five years.

No party challenges the use of the five-year average. However, both the Department and AARP object to the inclusion of the costs associated with the *Patch* case. The Department asserts that the issues that CVPS litigated related to the power costs that would be charged to CVEC customers, not CVPS ratepayers. As such, the costs for the litigation should be borne by CVEC or CVPS shareholders.²³¹ AARP supports the Department's recommendation.

CVPS maintains that the *Patch* case costs should be charged to Vermont ratepayers. According to CVPS, these costs were necessary to permit CVPS to obtain the sale of CVEC on terms that covered the power costs that CVPS had incurred to serve its subsidiary and thereby minimized the financial impact on CVPS's Vermont ratepayers. CVPS points out that, in the absence of the *Patch* litigation, CVPS's Vermont ratepayers would have ended up paying for all of the stranded costs when the power contract with CVEC was terminated.²³²

The Department's position would have merit if we could be assured that all of the

230. Schultz and DeRonne pf. at 57–58.

231. DPS Brief at 60.

232. CVPS Reply Brief at 182–183.

financial impacts of the NHPUC's restructuring order would have been borne by CVEC's ratepayers or by shareholders. But, as we discuss in the previous section, under traditional ratemaking in Vermont, it is likely that CVPS's Vermont ratepayers would have absorbed at least part, if not all, of the excess stranded costs.

CVPS's pursuit of the *Patch* case and FERC litigation avoided the potential for shifting these significant excess power costs to CVPS's Vermont ratepayers. For this reason, we accept CVPS's position that it is reasonable to assign half of the costs of the *Patch* litigation to retail customers.

D. Depreciation Expense

Findings

190. CVPS's annual depreciation expense results from the application of revised depreciation rates calculated in a depreciation study prepared in 2001, and based on CVPS's plant in service balances as of December 31, 2000. Majoros pf. at 4–5; exh. DPS-MJM-1.

191. CVPS began using the depreciation rates calculated in its 2001 depreciation study on April 1, 2002. Majoros pf. at 5.

192. Plant and equipment are removed from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removing the retired plant less the value received for the salvage is net salvage. Net salvage can be positive or negative. Majoros pf. at 20, 33.

193. CVPS's current depreciation rates include a component for future negative net salvage of at least \$1.6 million per year. Majoros pf. at 21 and 33; exh. DPS-MJM-1 at 8; exh. DPS-MJM-3 at page 8 of statement C.

194. During the most recent five-year period available, CVPS's actual expenditures for net salvage have been, on average, positive \$0.5 million. Majoros pf. at 21, 33; exh. DPS-MJM-3 at statement D.

195. An asset retirement obligation ("ARO") is a liability resulting from a legal obligation to retire or decommission a plant asset. In this context, a legal obligation is "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or

oral contract or by legal construction of a contract under the doctrine of promissory estoppel." Exh. CVPS-40 at 4; 103 FERC ¶ 61,021 at ¶ 2 (FERC 2003) (referred to herein as "FERC Order 631").

196. Statement of Financial Accounting Standards No. 143 ("SFAS 143") was issued in June 2001. SFAS 143 requires that prior and future amounts of "non-legal AROs"²³³ be reported as a regulatory liability in financial statements. Majoros pf. at 22, 25.

197. As a result of SFAS 143, in 2002 CVPS identified \$4.3 million of non-legal ARO collections relating to prior years that were included in its accumulated depreciation account. This \$4.3 million was classified as a regulatory liability. Majoros sur. pf. at 5, 25–26; exh. CVPS-10 at 59.

198. CVPS's regulatory liability associated with non-legal ARO collections grew to \$5.2 million at the end of 2003. Majoros sur. pf. at 26; exh. CVPS-10 at 59.

199. FERC Order 631 was issued on April 9, 2003. It requires an identification of amounts accrued for cost of removal for non-legal retirement obligations that are included in the depreciation reserve. It also requires jurisdictional entities to maintain subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal AROs included in depreciation accruals. R. White reb. pf. at 20.

200. The matching principle of accounting provides that both initial and future expenditures should be allocated to the accounting periods in which the service potential of an asset is consumed. R. White reb. pf. at 9.

201. The standard or criterion that should be used to determine a proper net salvage rate is cost allocation over economic life in proportion to the consumption of the service potential. R. White reb. pf. at 9.

202. The economic principle underlying both the accounting and ratemaking treatment of cost of removal is that in addition to return of and return on invested capital and taxes, a revenue requirement for cost of removal is created when an asset is placed in service. R. White reb. pf. at 9.

233. If a company does not have a legal obligation to retire or decommission a plant asset, the cost of removing that plant asset is considered a non-legal retirement obligation (referred to herein as a "non-legal ARO").

203. If CVPS has over-collected from ratepayers for the cost of future net salvage, ratepayers should receive rate relief through downward adjustments in CVPS's net salvage rates. Tr. 1/10/05 at 60 (R. White).

204. CVPS's depreciation expense should be increased by \$1,172 in Rate Year 1 and by \$51,780 in Rate Year 2 to correct an error in CVPS's original cost-of-service filings related to deferred hydro relicensing costs. Schultz and DeRonne pf. at 19; exh. CVPS-4.

205. CVPS's depreciation expense should be reduced by \$19,233 in Rate Year 1, and \$80,486 in Rate Year 2 to reflect changes to CVPS's plant balances. These adjustments incorporate the corrections to CVPS's communications plant balances that are shown on exh. CPVS-4. Schultz and DeRonne pf. at 18; exh. CVPS-4 at pages 2–4; exh. DPS-L&A-11 at schedule 5; exh. DPS-L&A-12 at schedule 5.

Discussion

Depreciation allows the recovery of the cost of an asset to be spread over the asset's expected life, thereby enabling all ratepayers who benefit from the asset to pay a portion of the asset's cost. Traditionally, net salvage is also collected through depreciation rates.²³⁴ Depreciation rates are established based on depreciation studies that review the assumptions underlying the current depreciation rates.

In these proceedings, the DPS argues that CVPS's depreciation expense should be adjusted for three reasons.²³⁵ First, the DPS asserts that depreciation expense should be increased to correct an error in CVPS's original filing related to the Company's deferred hydro relicensing costs. CVPS agrees with this adjustment. The proposed adjustment, which is shown in finding 204, above, is appropriate, and we hereby accept it.

Second, the DPS argues that depreciation expense should be reduced to reflect the DPS's recommended changes to plant balances. CVPS does not contest the adjustment of depreciation

234. R. White reb. pf. at 9; DPS Brief at 82.

235. The DPS also states that CVPS's depreciation expense should be reduced because several of the average lives on which the depreciation rates are based are too short. However, the DPS does not propose alternative lives in these proceedings, stating instead that it expects CVPS's next depreciation study to address this issue. Majoros pf. at 6.

expense to reflect changes to plant balances (although the Company does contest the adjustments to the plant balances, as discussed in Section V.A, above). It is appropriate to modify depreciation expense to reflect adjustments to plant balances. Since we have accepted the DPS's recommended changes to CVPS's plant balances, we also accept the DPS's proposed adjustments to depreciation expense that reflect the effects of those changes (*see* finding 205, above).

Third, the DPS advocates reducing CVPS's depreciation expense because future net salvage is bundled into CVPS's depreciation rates, even though CVPS has no legal obligation to incur those costs.²³⁶ The DPS argues that net salvage should be separated from other depreciation expenses through the use of a "net salvage allowance" that is, in essence, a normalized expense. According to the DPS, the net salvage allowance should be equal to the average of the last five years' net salvage expense (whether that amount is positive or negative). However, in these proceedings, as a transitional measure, the DPS recommends a zero net salvage allowance, rather than the positive \$0.5 million net salvage allowance that would apply if a five-year average was used.²³⁷ To support its position, the DPS points out that CVPS has collected considerably more in net salvage than it has spent, on average, over the last five years. The DPS argues that this proves that CVPS's net salvage rates are excessive.²³⁸

CVPS does not agree with the DPS's position regarding the collection of net salvage. CVPS asserts that it is appropriate to continue to collect net salvage through depreciation rates, regardless of whether CVPS has a legal obligation to incur those costs. As a practical matter, CVPS asserts that even though it may not have a legal obligation to incur removal costs for most of its plant, it does in fact incur removal costs.²³⁹ CVPS argues that the DPS's net salvage allowance proposal would create intergenerational inequities because, under that proposal, the entire cost of removal of an asset would be born by ratepayers at the time the asset is retired, rather than spread among all ratepayers who benefitted from the use of the asset.²⁴⁰ CVPS asserts that comparing its annual collections for net salvage with its realized net salvage costs is

236. Majoros pf. at 6.

237. Majoros pf. at 36–37.

238. DPS Brief at 77.

239. CVPS Reply Brief at 216.

240. R. White reb. pf. at 3–4, 14–15.

inappropriate because annual collections are for the future removal of all plant now in service, not just to pay for the plant that was retired in a particular year.²⁴¹ CVPS asserts that its net salvage rates will be reexamined as part of its next depreciation study, which it expects to conduct in 2006.²⁴²

The DPS has highlighted an important policy issue — in contrast to collections for depreciation, which enable the utility to recover costs that it has already incurred, collections for net salvage are, in essence, prepayments by ratepayers for expenses that the utility estimates it will incur at some point in the future. This is a significant distinction, and one that persuades us that collections for net salvage should be tracked and reported separately from other funds collected via depreciation expense. For this reason, we accept the DPS's recommendation that we require CVPS to follow the recording and reporting requirements of FERC Order 631 for Vermont jurisdictional ratemaking purposes. In other words, CVPS must track and report its prior and future net salvage collections in a separate subsidiary account, and we expect this separate account to be shown in future cost-of-service filings.²⁴³

However, we do not require CVPS to stop collecting net salvage through its depreciation rates. Intergenerational equity is of great concern to us. CVPS has convinced us that to adopt the DPS's recommendation regarding a net salvage allowance would create inequities by requiring ratepayers at the time an asset is retired to pay all the net salvage costs (or allow ratepayers at the time an asset is retired to receive the benefit if the net salvage costs are negative).²⁴⁴ Instead, net salvage costs should be recovered from ratepayers over an asset's expected lifetime. This concept of spreading cost recovery over time to match the costs with the benefits is similar to the purpose behind depreciation. Given that depreciation and net salvage rates are determined using

241. CVPS Reply Brief at 216.

242. Tr. 1/10/05 at 75–76 (R. White); tr. 1/12/05 at 146 (Gibson).

243. We believe this issue may also have implications for CVPS's next depreciation study. In addition to changing depreciation rates, depreciation studies often lead to "rebalancing" the depreciation reserve among different plant accounts. We would expect that any future rebalancing would not shift funds from net salvage to depreciation or vice versa. Collections for past expenses should be kept separate from collections for estimated future expenses. This expectation is consistent with statements made by CVPS's chief financial officer during cross-examination. Tr. 1/12/05 at 114–115 (Gibson).

244. During cross-examination, the DPS's own witness admitted that under the DPS's recommendation, ratepayers at the time an asset is retired would pay all the net salvage costs for that asset. Tr. 1/10/05 at 140 (Majoros).

the same service life estimates and dispersion patterns, it is acceptable for the collection mechanism (the depreciation rate itself) to combine net salvage with depreciation, provided that the recoveries for the two items are tracked and reported separately, as discussed above.

We are not persuaded by the DPS's argument that, because CVPS has collected more in net salvage than it has spent, on average, over the last five years, the Company has overcollected net salvage. Because the recovery of net salvage costs is spread over an asset's lifetime, while actual net salvage expenses are linked to a particular year's retirements, it would be surprising if collections for net salvage matched CVPS's net salvage expenses in any particular year.²⁴⁵

In addition, we disagree with the DPS's characterizations of SFAS 143 and FERC Order 631,²⁴⁶ both of which were enacted subsequent to CVPS's last depreciation study. Rather, we are persuaded by CVPS's arguments, and the actual language of the two documents that, for regulated entities, these new policies impose new tracking and reporting requirements for non-legal AROs, but do not require that net salvage costs no longer be recovered through depreciation rates.²⁴⁷

Finally, the DPS has recommended that we order CVPS to conduct a new depreciation study immediately. We decline to do so at this time. In making this decision, we are relying on CVPS's representation that it will conduct a new depreciation study in either 2005 or 2006, which is five years after its last depreciation study was performed. We are persuaded that it is reasonable to conduct a new depreciation study every five years, and decline to order the Company to do so more frequently. Nevertheless, we are very interested in the results of CVPS's next depreciation study, and we require the Company to file it with the Board and the DPS when it is completed, which should be no later than December 31, 2006.

245. We are expressly not ruling on whether CVPS has overcollected net salvage during the period that its current depreciation rates have been in effect. There is insufficient evidence in the record to decide this issue. We expect, however, that the level of net salvage collections will be reviewed in CVPS's next depreciation study, and that net salvage rates will be adjusted downward at that time if the data shows that to be appropriate.

246. The DPS asserts that SFAS 143 and FERC Order 631 require the separation or unbundling of non-legal cost of removal allowances from depreciation rates, although the DPS admits that SFAS 143 provides an exception for regulated utilities, provided certain conditions are met. *Majoros* pf. at 24 –25, 31.

247. Exh. CVPS-40 at 7, 42; FERC Order 631 at ¶¶ 37–39.

Correction to Annualized Test Year Depreciation Expense

As explained in finding 130 and Section V.B, above, CVPS's original filing includes an error in the calculation of annualized test year depreciation expense. No party has asked that CVPS's depreciation expense calculation be revised to reflect the Company's correction of its annualized test year depreciation expense. Nevertheless, we conclude that the error should be corrected. Therefore, we require CVPS, as a part of its compliance filing in these proceedings, to adjust depreciation expense in both Rate Year 1 and Rate Year 2 to reflect the correct value of annualized test year depreciation expense.

E. Payroll-Related Items

1. Number of Employees

Findings

206. On December 31, 2003 (the end of the test year in these proceedings), CVPS had 514 employees and 11 vacant positions. Gamble pf. at 39; tr. 1/11/05 at 20 (Gamble); exh. CVPS-JFG-9; exh. CVPS-JFG-16; exh. CVPS-JFG-17.

207. CVPS's filed cost of service for Rate Year 1 includes 34.5 employees more than CVPS had as of December 31, 2003, for a total of 548.5 full-time equivalent employees. CVPS's filed cost of service for Rate Year 2 includes 7 more employees than its Rate Year 1 cost-of-service, for a total of 555.5 full-time equivalent employees. Tr. 1/11/05 at 21 (Gamble).

208. As of August 17, 2004, CVPS had 524.3 full-time equivalent employees. Tr. 1/11/05 at 21–22 (Gamble).

209. As of October 31, 2004, CVPS had 527 full-time equivalent employees. Tr. 1/11/05 at 23 (Gamble).

210. As of December 2004, CVPS had around 530 full-time equivalent employees. The Company had 5.5 fewer full-time equivalent employees than it had projected in its cost-of-service filings that it would have in December 2004. Tr. 1/11/05 at 28, 34–35 (Gamble).

211. CVPS filled 16 new positions in calendar year 2004. However, nine months into Rate Year 1, CVPS still had approximately 18 fewer employees than it included in its Rate Year 1 cost of service. Findings 206, 207, and 210, above.

212. CVPS originally budgeted for 532.2 full-time equivalent employees in 2005. Schultz and DeRonne pf. at 50.

213. As of January 11, 2005, only six external positions were listed as open on CVPS's website, one of which was for Catamount, Inc. This is not a complete list of CVPS's job openings because (1) when a job becomes open, it is first posted internally and not on CVPS's website, and (2) the list on the website does not include jobs for which someone has been hired from outside the Company, but has not yet started work. Tr. 1/11/05 at 24–27 (Gamble).

214. CVPS's original cost-of-service filings for both rate years did not account for ongoing vacancies. Gamble reb. pf. at 34.

215. CVPS's five-year average turnover rate is 6.2 percent. The lowest number of employees to leave CVPS in any one year since 1999 has been 25. Twelve employees left CVPS between January 1, 2004 and August 17, 2004. Schultz and DeRonne pf. at 49.

216. CVPS's requested number of employees should be reduced by 11 in each rate year in order to account for vacancies. Schultz and DeRonne pf. at 49; findings 214–215, above.

217. The average compensation expense for the 34.5 positions added by CVPS in Rate Year 1 was \$24,806. CVPS's Rate Year 1 cost of service should be reduced by \$272,866, which is \$24,806 times 11 positions. Schultz and DeRonne pf. at 51.

218. The average compensation expense for the 41.5 positions added by CVPS in Rate Year 2 was \$32,571. CVPS's Rate Year 2 cost of service should be reduced by \$358,280, which is \$32,571 times 11 positions. Schultz and DeRonne pf. at 51.

219. The electric industry has the oldest average age of employees among all industry groups, except for religious organizations. Gamble pf. at 40.

220. Based on CVPS's employee demographics, the Company expects a significant number of retirements to occur over the next 20 years. Gamble pf. at 41; exh. CVPS-JFG-18.

221. Sixteen of the additional full-time-equivalent employees included in CVPS's cost-of-service filings are related to succession planning for employees who will be retiring after the end of Rate Year 2. Ten of these 16 positions are related to Engineering and Operations. Due to the technical nature of this work, and to assure safety, it may take as long as four years to complete the training of qualified employees. Gamble pf. at 39–40.

Discussion

CVPS projected significant increases in the number of full-time equivalent employees during Rate Years 1 and 2, when compared to the test year for these proceedings. However, CVPS did not persuade us that these increases are known and measurable. On the contrary, as explained below, the evidence in this proceeding has convinced us that it is unlikely that CVPS's number of employees will increase as the Company originally projected.

The DPS and CVPS agree that the Company's requested number of employees should be adjusted downwards to account for vacancies. However, they disagree on the size of this adjustment. The DPS argues that the Company's turnover rate for the last five years supports the use of 11 vacancies (which was also the number of vacancies at the end of the test year).²⁴⁸ In addition, the DPS points out that CVPS's number of employees has been significantly below 548.5 throughout Rate Year 1, and nine months into Rate Year 1, CVPS still had approximately 18 unfilled positions.²⁴⁹

CVPS argues that this figure is too high because it includes retirements and involuntary terminations, in addition to voluntary terminations. CVPS asserts that retirements and involuntary terminations should not be used to calculate the vacancy rate because (1) CVPS is prehiring replacements for impending retirements, therefore the vacancy rate related to retirements is expected to approach zero; and (2) in the past few years, there were a high number of involuntary terminations, especially related to raising the bar on management performance, and it is not reasonable to expect that this high level of involuntary terminations will continue at the same rate.²⁵⁰ As a result, CVPS recommends a rate of 3.7 vacancies.²⁵¹

We are persuaded that the DPS's vacancy rate is more appropriate. Not only does 11 vacancies better match CVPS's historic turnover rate, using this vacancy rate also brings the number of employees included in the cost of service closer to the actual number of employees

248. Schultz and DeRonne pf. at 49.

249. DPS Brief at 54.

250. Gamble reb. pf. at 34–35.

251. CVPS uses an average of 11 voluntary terminations per year, and the average time to fill most positions of 4 months to calculate its vacancy rate of 3.7. Gamble reb. pf. at 35.

that CVPS had during the first nine months of Rate Year 1.

With respect to Rate Year 2, in order for CVPS to reach its projected number of employees, it would have to hire all the employees it originally anticipated hiring in Rate Year 1 but did not, plus the seven additional employees it originally projected hiring in Rate Year 2. CVPS has not convinced us that it will hire all these additional employees during Rate Year 2, particularly since its 2005 budget (which covers three months of Rate Year 1 and nine months of Rate Year 2) included only 532.2 employees, far fewer than the 555.5 employees included in CVPS's Rate Year 2 cost of service.

CVPS has argued that the vacancy rate related to retirements is expected to approach zero, and that there will be fewer involuntary terminations during the rate years. These assertions may be true. However, they do not change the fact that nine months into Rate Year 1, CVPS still had approximately 18 unfilled positions, and there is nothing in the record that convinces us that this situation will change significantly in Rate Year 2.²⁵²

We note, however, that reducing CVPS's number of employees by a vacancy rate of 11 still leaves approximately 7 positions unfilled nine months into Rate Year 1, and an additional 7 positions to be filled in Rate Year 2. Even though it could be argued that these additional positions are not known and measurable, we do not reach that conclusion in this Order. Rather, CVPS has persuaded us that it is necessary for its staffing levels to increase slightly in order to train new employees who can replace those expected to retire after Rate Year 2.²⁵³ We recognize that the aging of the workforce is an issue confronting the electric utility industry as a whole, and we are pleased that CVPS is planning for expected retirements. Our decision today takes into consideration CVPS's decision to prehire replacements for some impending retirements in order to ensure that the replacements are adequately trained. An adequately-trained workforce will benefit ratepayers; for this reason, we allow CVPS to include the costs of

252. On January 11, 2005, CVPS had only six positions advertised on its website (one of which was for an unregulated subsidiary). We recognize that these six positions do not include all jobs that the Company had posted as of January 11, 2005. However, there is no quantitative evidence in these proceedings regarding the number of jobs that the Company had posted internally as of that date, or of the number of jobs that were recently filled with outside hires who had not yet started work.

253. The record does not indicate how many of the approximately 16 new positions that the Company filled in calendar year 2004 were related to succession planning.

the remaining currently unfilled positions in rates.

2. Employee Incentive Plan

Findings

222. CVPS has an Employee Incentive Plan ("EIP") under which non-union employees (excluding officers) have the ability to earn an annual incentive payment if certain performance objectives are met. Gamble pf. at 27–28.

223. The EIP has a broad payout range. CVPS designed the EIP so there is a 90 percent chance of reaching the threshold performance level (below the threshold no payment is made), a 50 percent chance of reaching the target performance level (at which the target payout is made), and a 10 percent chance of reaching the maximum performance level (at which the maximum payout is made). The maximum payout is twice the target payout. Gamble pf. at 29.

224. CVPS requests in its filed costs of service the target payout amounts of \$887,380 in Rate Year 1, and \$1,187,760 in Rate Year 2. Gamble pf. at 29; tr. 11/2/04 at 35–36; exh. DPS-L&A-11 at page 2 of schedule 11; exh. DPS-L&A-12 at page 2 of schedule 11.

225. Fifty percent of CVPS's EIP is based on three Company-level measurements, and 50 percent of the EIP is based on specified team-level measures. Exh. CVPS-JFG-33 at 3.

226. The three Company-level measures used to calculate CVPS's EIP, along with the weight given to each, are: (1) utility earnings per share (50 percent); (2) cash flow (25 percent); and (3) whether CVPS meets its service quality standards (25 percent). Exh. CVPS-JFG-33 at 3.

227. The Team-level measures used to fund CVPS's EIP are divided among four categories: financial, customer, process, and people. For teams that work with external customers, the customer measures are given a weighting between 35 and 45 percent. Exh. CVPS-JFG-33 at 3.

228. The EIP's 2004 target for utility earnings per share is \$1.24, while the utility earnings per share for 2002 and 2003 were \$1.49 and \$1.57, respectively. Schultz and DeRonne pf. at 43.

229. Fifty percent of CVPS's requested EIP expense (in other words, 50 percent of the target payout amount) should be disallowed in Rate Year 1 in order to share the expected costs of the EIP equally between shareholders and ratepayers. Schultz and DeRonne sur. pf. at 41–42.

230. Fifty percent of the Company's requested EIP expense should be disallowed in Rate

Year 2, after removing an amount that is not known and measurable as provided in confidential exh. CVPS-JFG-29, in order to share the expected costs of the EIP equally between shareholders and ratepayers. Schultz and DeRonne sur. pf. at 41–42; exh. CVPS-JFG-29.

231. CVPS's Vice President for Strategic Change and Business Services is responsible for overseeing all aspects of human resources, and was the Company's primary witness regarding the design of CVPS's EIP. Gamble pf. at 1, 27–33; Gamble reb. pf. at 25–33.

232. CVPS's Vice President for Strategic Change and Business Services incorrectly stated in her prefiled direct and rebuttal testimony, and during her live testimony during the direct portion of these proceedings that the weight given to the three Company-level measures used to fund CVPS's EIP were: (1) utility earnings per share (*25 percent*); (2) cash flow (25 percent); and (3) whether CVPS meets its service quality standards (*50 percent*).²⁵⁴ Gamble pf. at 30; Gamble reb. pf. at 26, 28; tr. 11/2/04 at 36 (Gamble); exh. CVPS-JFG-33 at 1.

233. CVPS's Vice President for Strategic Change and Business Services did not discover the error described in finding 232, above, until sometime after the rebuttal hearings in these proceedings when she began looking back at the Company's 2004 performance. Exh. CVPS-JFG-33 at 1.

Discussion

The DPS argues that 50 percent of the amount CVPS has requested for its EIP should be excluded from the costs of service for both Rate Years 1 and 2 because: (1) the EIP is based 75 percent on financial goals and only 25 percent on meeting service quality and reliability goals; (2) the EIP's goals are not appropriate because they are set too low; (3) CVPS lowered its earnings per share goal because earnings are expected to decrease due to the sale of CVEC and the return of costs previously paid by CVEC customers to Vermont ratepayers; and (4) the EIP has too many discretionary measures for which there is no means to verify that the decisions are justified.²⁵⁵ Alternatively, the DPS argues that 50 percent of the amount CVPS has requested for

254. The italics indicate the errors. As can be seen by comparing finding 232 with finding 226 which indicates the correct weights for the three measures, the percentage weights for "utility earnings per share" and "whether CVPS meets its service quality standards" were reversed.

255. DPS Brief at 52.

its EIP should be disallowed in order to provide for an equal sharing of costs between ratepayers and shareholders.²⁵⁶

CVPS argues that the requested amount for its EIP (which is the target payout amount) should be allowed because its EIP is necessary to provide employees incentives for cost-effectively meeting the Company's goals, and to enable the Company to remain competitive with the marketplace.²⁵⁷ CVPS also asserts that the DPS has misunderstood the EIP's components. CVPS explains that its EIP is based 50 percent on Company measures, and 50 percent on Team measures. The Company states that the DPS is correct that 75 percent of its Company measures are financial goals, and 25 percent are service quality and reliability goals, but asserts that the DPS ignores the contribution of Team measures. According to CVPS, for teams that work with external customers, between 35 and 45 percent of the Team measures are focused on customer-oriented goals. Therefore, for teams that work with external customers, between 30 and 35 percent of the EIP is based on customer-focused goals (including both the Company and Team measures).²⁵⁸ Finally, CVPS argues that not all of its teams have discretionary goals, but that discretionary goals are necessary for some of its teams in order to prevent "absurd results."²⁵⁹

We do not dispute CVPS's contention that its EIP provides its employees with incentives for cost-effectively meeting the Company's goals. However, the Company's goals benefit both shareholders and ratepayers. As a result, shareholders and ratepayers should share equally in the expected costs of the EIP.

We have two reasons for requiring that the EIP's expected costs be shared equally between shareholders and ratepayers. First, most of the EIP is not focused on customer goals. CVPS correctly points out the error in the DPS's assertion that only 25 percent of the EIP's overall weight is assigned to customer service and reliability goals. The Company has shown that only 25 percent of the EIP's Company measures are customer-oriented goals, but the overall weight, including the Team measures, is between 30 and 35 percent for those teams that work with external customers. Nevertheless, this range still indicates that only approximately one-

256. Schultz and DeRonne sur. pf. at 41–42.

257. CVPS Reply Brief at 169.

258. CVPS Reply Brief at 170–172.

259. CVPS Reply Brief at 172–173.

third of the EIP's weight is assigned to customer service and reliability goals.²⁶⁰

Second, the Company has set inappropriately low targets for some of the measures, particularly its utility earnings per share measure, which by itself accounts for 25 percent of the overall EIP. The 2004 target for this measure is 21 percent below actual 2003 utility earnings per share, and 17 percent below actual 2002 utility earnings per share. It is not appropriate to provide an incentive for performance significantly below the previous two years' achievements, particularly if, as the DPS argues, the target was reduced because CVPS's regulated utility operations will need to absorb nearly \$4 million of additional costs as a result of CVPS's sale of CVEC.²⁶¹

We are not basing our disallowance on the EIP's use of discretionary measures. CVPS has convinced us that discretionary goals are appropriate for some teams, and we do not conclude, at this time, that CVPS's EIP relies too heavily on discretionary measures. However, we remind CVPS that it is responsible for maintaining sufficient documentation justifying the discretionary determinations. Should CVPS fail to maintain such documentation, we may well reach a different conclusion regarding the EIP's reliance on discretionary measures in the future.

The remaining issue to decide is, "what are the EIP's expected costs?" CVPS has stated the EIP was designed so there would be a 50 percent chance of reaching the target performance level, which would result in the target payout being made. Thus, it is equally likely that CVPS would pay more or less than the target payout. As a result, we conclude that the target payout level is the best estimate of the EIP's expected costs in each of the rate years.²⁶² Therefore, we

260. CVPS stated that for 2005, the weighting of the Company portion of the EIP has been changed to: (1) 33 1/3 percent utility earnings per share; (2) 33 1/3 percent cash flow; and (3) 33 1/3 percent whether CVPS meets its service quality standards. Substituting these percentages in the calculation performed on page 3 of exh. CVPS-JFG-33 results in an overall weight of between 34 percent and 39 percent for customer-oriented goals. These percentages are still considerably less than half of the EIP's overall weight.

261. Schultz and DeRonne sur. pf. at 38.

262. The only other basis upon which we could estimate the EIP's expected costs in the rate years would be to use past EIP payout levels as a guide for future expected payout levels. According to CVPS, the EIP's actual payout for 2002 performance was 68 percent of the maximum possible payout for regular employees, and 69 percent of the maximum possible payout for key contributors. The EIP's actual payout for 2003 performance was 70 percent of the maximum possible payout for regular employees, and 71 percent of the maximum possible payout for key contributors. Gamble pf. at 32–33.

Even though the payout levels for these two years were both near 70 percent of the maximum possible, we do not find it reasonable to assume that this level will continue. If the Company is correct that the EIP is designed so

are persuaded that 50 percent of the Company's requested EIP expense should be disallowed in Rate Year 1. In addition, we conclude that 50 percent of the Company's requested EIP expense should be disallowed in Rate Year 2, after removing an amount that is not known and measurable as provided in confidential exh. CVPS-JFG-29.²⁶³

Finally, we are compelled to comment on Ms. Gamble's error regarding the weights assigned to the utility earnings per share and service quality and reliability portions of the EIP. We do not believe Ms. Gamble deliberately misled the Board, and we believe that she acted properly in promptly informing the Company's legal department, who in turn immediately informed the Board and the other parties in these proceedings. Furthermore, we realize that everyone makes a mistake occasionally. Nevertheless, we are astounded that someone in her position could make this particular mistake not once, but *three times*, both orally and in written prefiled testimony. We are very troubled that the Company's senior executive with primary responsibility for overseeing all aspects of human resources, including the implementation of CVPS's EIP, could have such a fundamental misconception regarding the EIP's priorities. We are very interested in the way the EIP balances shareholder and ratepayer concerns, and we were disturbed to discover late in these proceedings that the EIP accorded only half as much significance to the Company's service quality and reliability goals and twice as much significance to utility earnings per share as CVPS's senior executive with responsibility for the EIP thought it did. This situation reinforces our original concern regarding the EIP's balance between shareholder and ratepayer interests, which we have addressed in this Order through an equal sharing of the EIP's expected costs between shareholders and ratepayers.

there is only a 50 percent chance of meeting the target payout, that is true for each year that the EIP is in effect; past payout levels would not be any indication of future payout levels. (Similarly, if one flips a coin four times and the first three times it comes up heads, the probability that it will come up heads again is still 50 percent. The events are independent, and past results do not affect the probability of future events.)

263. Confidential exh. CVPS-JFG-29 was filed with Ms. Gamble's supplemental testimony describing the results of CVPS's recent negotiations with its employee union. The new union contract covers the period January 1, 2005–December 31, 2008. Gamble sup. pf. at 3.

3. Officers' Compensation

Findings

234. CVPS multiplied the total salaries of all Vermont regulated utility employees (including officers) by an adjustment factor of 74.85 percent to calculate the Operations and Maintenance portion of those employees' salaries. The 74.85 percent adjustment factor is based on the percentage of compensation dollars that are spent, on average, by all utility employees working on Operations and Maintenance activities, as opposed to capital projects, unregulated activities, or other "below-the-line"²⁶⁴ activities. Gamble pf. at 43; Gamble reb. pf. at 37–38.

235. The DPS asked CVPS to provide information regarding individual officers' compensation that was charged below-the-line. CVPS initially provided no information regarding how individual officers' compensation was allocated between ratepayers and shareholders, and later provided a calculation that shows that 88.9 percent of a particular unidentified officer's time was charged to Vermont utility operations during the test year. Schultz and DeRonne pf. at 51–52; Schultz and DeRonne sur. pf. at 43–44; Gibson reb. pf. 11/15/04 at 28–29.

236. Because CVPS failed to demonstrate that an appropriate amount of officers' compensation has been charged below-the-line, 10 percent (\$96,514) of the requested amount of officers' compensation should be removed from the costs of service for both Rate Years 1 and 2. Schultz and DeRonne pf. at 52.

Discussion

A long-standing regulatory principle is that ratepayers should not pay for costs incurred to support a utility's unregulated affiliates or other below-the-line activities. It is the utility's responsibility to maintain records that will allow regulators to verify that costs, including payroll costs, allocated to activities that are excluded from ratemaking are not included in a utility's cost

264. "Below-the-line" is a regulatory term of art that is used to refer to items that are charged (or credited) to shareholders. "Above-the-line" is the term of art used to refer to items that are charged (or credited) to ratepayers. Literally, "the line" refers to the line on the utility's income statement (Net Utility Operating Income) that is the dividing point between items that are charged (or credited) to ratepayers versus shareholders.

of service.²⁶⁵

In these proceedings, CVPS has failed to provide records showing what portion of its officers' compensation was charged below-the-line. Instead, it relies upon an allocation percentage that was calculated based upon how all employees spend their time. However, the DPS has argued that officers provide a different level of service to regulated and unregulated operations than the general employee complement.²⁶⁶ CVPS notes another difference between how officers spend their time compared to employees as a whole — officers generally do not spend time on capital projects.²⁶⁷ For these reasons, the evidence presented by CVPS regarding the allocation of one officer's compensation is insufficient to support the use of an allocation factor that is based on all employees' compensation.

CVPS has asserted that the actual allocation of individual officers' compensation is not readily available because specific employee salaries lose their identity in the Company's general ledger system.²⁶⁸ This is not an acceptable reason to fail to provide appropriate documentation regarding the allocation of officers' compensation. It is CVPS's responsibility to ensure that its recordkeeping enables the Company to provide information regarding the allocation of all costs, including payroll costs, above- and below-the-line.

Because CVPS has not provided information regarding the actual allocation of individual officers' compensation, we are unable to ascertain whether 74.85 percent is the correct factor to use to allocate the officers' time. The Company has not met its burden of proof on this issue. Therefore, we accept the DPS's proposed additional 10 percent reduction to officers'

265. As the Board stated in Dockets 5841/5859:

We require utilities operating in this state to keep clear and detailed records that provide justification for corporate costs that are allocated to an affiliate. . . . It is thus critical that a company like Citizens, whose corporate structure is characterized by a variety of affiliates and profit centers, be able to fully document and justify transactions among the entities. In view of this structure, it is essential that the Company demonstrate the reasonableness of *all* charges to Vermont ratepayers. If such expenses cannot be fully substantiated and documented, we would have no choice but to exclude them from rates in the future.

Dockets 5841/5859, Order of 6/16/97 at 231 (emphasis in original).

266. Schultz and DeRonne pf. at 51.

267. Gibson reb. pf. at 29.

268. Gibson reb. pf. at 28; tr. 11/3/04 at 29–30 (Gibson).

compensation.²⁶⁹ It is imperative that a utility's failure to meet its recordkeeping responsibilities not result in a windfall to the company, or its corporate officers.²⁷⁰

4. Other Payroll Adjustments

Findings

237. Temporary employee salaries for Rate Year 2 should be reduced by \$91,175. Gamble reb. pf. at 37; Schultz and DeRonne pf. at 51; exh. CVPS-4.

238. Wages and salaries for Rate Years 1 and 2 should be reduced by \$68,720, and \$20,560, respectively, to correct errors in CVPS's original filing. Gamble pf. at 42; exh. DPS-L&A-11 at page 2 of schedule 11; exh. DPS-L&A-12 at page 2 of schedule 11.

Discussion

CVPS and the DPS have agreed that two additional adjustments should be made to payroll, as described in findings 237–238, above. We conclude that the adjustments are reasonable and should be made.

5. Payroll Tax Expense

Findings

239. Payroll tax expense should be adjusted to reflect the adjustments made to payroll expense. Gibson pf. at 31.

240. The payroll tax expense adjustment should be calculated by multiplying the respective payroll expense adjustments by the test year's effective social security rate of 7.12 percent. Schultz and DeRonne pf. at 53.

269. This adjustment results in an allocation factor of 67.365 percent — $0.7485 * 0.9 = 0.67365$ or 67.365 percent.

270. It would be inappropriate for a utility's failure to keep accurate records regarding the allocation of its officers' time to result in higher retail rates and increased collections from ratepayers, which could lead to higher earnings per share which, in turn, could result in increased incentive compensation for the utility's management.

Discussion

CVPS and the DPS agree that payroll tax expense should be adjusted to reflect the adjustments made to payroll expense. However, they disagree on the effective tax rate that should be used in the calculation.

The only effective tax rate in the evidentiary record in these proceedings is that proposed by the DPS — 7.12 percent. In CVPS's reply brief, it asserts that the Company used a combined tax rate of 7.65 percent to calculate its payroll tax expense, and argues that "the DPS calculated rate must be rejected so that the Company can recover its rate year Social Security tax expense."²⁷¹

The payroll tax expense is a combination of social security tax expense and medicare tax expense. Based on our experience with utility company payroll tax expense, we know that medicare tax is assessed on all of each employee's earnings, but social security tax is only assessed on each employee's earnings up to a certain limit, which is changed by the federal government each calendar year. As a result, it is common for a utility company's total payroll tax expense to be less than would result if the full 7.65 percent tax rate that is applied to individual employees' earnings below the specified limit were applied to the company's total payroll expense.

This is, in fact, what occurred for CVPS in 2003, as shown by the DPS. The DPS divided CVPS's test year payroll tax expense of \$1,868,807 by CVPS's test year payroll of \$26,234,661 to arrive at an effective payroll tax rate of 7.12 percent.²⁷² The DPS has proposed using this effective payroll tax rate to calculate the adjustment to payroll tax expense.

In other words, the DPS has proposed using a lower effective payroll tax rate to calculate its reduction to payroll tax expense than CVPS has proposed. This results in a smaller reduction to payroll tax expense than if the Company's proposed effective tax rate was used.²⁷³ As a

271. CVPS Reply Brief at 178.

272. Exh. DPS-L&A-11 at schedule 12; exh. DPS-L&A-12 at schedule 12.

273. The DPS has proposed a \$53,332 reduction to payroll tax expense in Rate Year 1, and a \$82,150 reduction to payroll tax expense in Rate Year 2. For comparison purposes, multiplying the same payroll adjustment shown on exh. DPS-L&A-11 at schedule 12, by CVPS's proposed effective tax rate results in a \$57,274 reduction to payroll tax expense in Rate Year 1, and a \$88,222 reduction to payroll tax expense in Rate Year 2.

result, we are confused by CVPS's assertion that if the DPS's effective tax rate is used, the Company will not recover its rate year Social Security tax expense. On the contrary, if the DPS's effective payroll tax rate is used, the Company will collect more payroll tax from ratepayers than it would if its proposed effective tax rate were used to calculate the adjustment.

We recognize that CVPS's effective payroll tax rate during the rate years may be higher or lower than 7.12 percent. However, based on the evidence in the record, we cannot conclude that there is a known and measurable change to the effective payroll tax rate for the rate years. Thus, we accept the DPS's proposed effective tax rate for the purpose of calculating the adjustment to payroll tax expense for two independent reasons: first, because substantively it is the appropriate effective payroll tax rate to use, and second, because CVPS's proposed effective payroll tax rate is not in the evidentiary record in these proceedings.

In the Company's compliance filing, CVPS should include an adjustment to payroll tax expense that is equal to 7.12 percent times our approved adjustments to payroll expense.

6. 401(k) Expense

Findings

241. 401(k) expense should be adjusted to reflect the adjustments made to payroll expense. Frankiewicz pf. at 10.

242. The 401(k) expense adjustment should be calculated by multiplying the respective payroll expense adjustments by the test year's effective 401(k) employer match rate of 2.95 percent. Schultz and DeRonne pf. at 56.

Discussion

CVPS and the DPS agree that 401(k) expense should be adjusted to reflect the adjustments made to payroll expense. However, they disagree on the effective employer match rate that should be used in the calculation.²⁷⁴

274. We were surprised to learn of this disagreement for the first time in CVPS's brief. During the direct hearings, Board staff asked the DPS's cost-of-service witness whether the DPS's proposed adjustment to 401(k) expense was the result of a dispute with the methodology the Company used to calculate its proposed adjustment, or whether it was simply the result of the DPS's recommended payroll adjustment. The DPS's witness replied that the

The only effective employer match rate in the evidentiary record in these proceedings is that proposed by the DPS — 2.95 percent. In CVPS's reply brief, it asserts that the DPS employer match rate should be rejected.²⁷⁵ However, neither CVPS's calculation of its 401(k) expense nor its recommended employer match rate are in the evidentiary record.²⁷⁶ Therefore, we accept the DPS's proposed effective tax rate for the purpose of calculating the adjustment to payroll tax expense.

In the Company's compliance filing, CVPS should include an adjustment to 401(k) expense that is equal to 2.95 percent times our approved adjustments to payroll expense.

F. Medical Insurance

Findings

243. CVPS's average medical insurance cost per employee, prior to capitalization, in Rate Year 1 is \$10,118. A Hewitt Associates study shows the national average total medical insurance cost per employee in 2003 was \$6,295. Schultz and DeRonne pf. at 53.

244. CVPS's average medical cost per employee is higher than the national average per employee because: (1) CVPS's plan has 2.6 dependents per employee — for comparison purposes, Cigna, the second largest provider of insurance for privately insured individuals in Vermont, has a national average contract size of only 2.25 dependents per employee; (2) CVPS's workforce is older than the national average, and older employees generally have higher medical expenses; and (3) Vermont health care is more costly than the national average because there is less competition for medical services in Vermont. Gamble reb. pf. at 40; exh. CVPS-JFG-19; exh. CVPS-JFG-26.

245. CVPS employees' contribution to medical expense increased from 15 percent in 2003 to 19 percent in 2004. This change was not reflected in CVPS's costs of service for Rate Years 1

DPS's proposed adjustment was just a flow-through of the payroll adjustment. Tr. 11/4/04 at 93 (Schultz).

275. CVPS Reply Brief at 181.

276. We note that the DPS originally stated its recommended effective employer match rate in its direct prefiled testimony. CVPS had the opportunity to present evidence regarding its calculation of its 401(k) expense adjustment and its recommended effective employer match rate in the rebuttal phase of these proceedings, but the Company did not do so.

and 2. CVPS's medical expenses for Rate Years 1 and 2 should be reduced by \$118,772 to reflect this change. Gamble reb. pf. at 44; Gamble sup. pf. at 6; exh. DPS-L&A-11 at schedule 13; exh. DPS-L&A-12 at schedule 13.

246. CVPS's most recent agreement with its employees' union provides for: (1) significant increases in employee co-pays for hospital stays, outpatient surgery, office visits, and pharmaceutical drugs, beginning April 1, 2005; and (2) increases in employees' health insurance premiums, beginning in 2006. Non-union employees will experience the same increases in employee co-pays. Gamble sup. pf. at 4–5; exh. CPVS-JFG-28 at 1.

247. According to CVPS's medical insurance broker, employers with more than 500 employees expect to experience a 14 percent increase in medical insurance costs in 2004. In addition, estimates of increases in medical insurance costs for 2005 range from 12 percent to 18 percent. Gamble reb. pf. at 38; exh. CVPS-JFG-19.

248. The State of Vermont projects increases in its medical insurance costs for its two largest insurance plans of 16 and 18 percent between fiscal years 2004 and 2005, and 22 and 23 percent between fiscal years 2005 and 2006. Gamble reb. pf. at 39.

249. The fiscal year 2003 actuarial valuation under Statement of Financial Accounting Standards No. 106 prepared by Towers Perrin for CVPS shows inflation assumptions for pre-age 65 retiree medical costs of 8 percent, 7 percent, and 6 percent for 2004, 2005, and 2006, respectively. Schultz and DeRonne pf. at 55.

250. In April 2004, Towers Perrin provided CVPS updated inflation assumptions for pre-age 65 retiree medical costs of 12 percent, 11 percent, and 10 percent for 2004, 2005, and 2006, respectively. However, these rates were not part of a completed actuarial report. Tr. 1/11/05 at 19–20 (Gamble); exh. CVPS-JFG-24.

Discussion

The DPS argues that the medical expenses included in CVPS's cost-of-service filings are excessive because: (1) CVPS's medical cost per employee is significantly above the national average in 2003; (2) the medical inflation rates used by CVPS are too high; and (3) CVPS failed

to reduce its medical costs by the increase in employee contributions to medical costs between 2003 and 2004.²⁷⁷

CVPS disagrees with the DPS's first two arguments, but agrees that its medical expenses should be reduced to reflect the increase in employee contributions between 2003 and 2004.

CVPS admits that its medical insurance costs per employee are above the national average, in part due to the Company's "generous medical program design."²⁷⁸ However, CVPS has persuaded us that this is not the only reason CVPS's medical insurance costs are above the national average.²⁷⁹ In addition, CVPS has taken steps to change its "generous" medical insurance program. CVPS's employee payments increased from 6.5 percent of total health claims in 2001 to 19.2 percent in 2004 (the national average is 20 percent).²⁸⁰ Furthermore, CVPS's new contract with its employee union increases employee co-pays substantially beginning in 2005, and provides for additional contribution increases beginning in 2006.

As for medical inflation rates, the evidence in these proceedings shows that expert estimates vary. The DPS's proposed inflation rates are based upon a 2003 actuarial valuation that was later updated (although not as part of a complete new report). The inflation rates from the 2003 report are significantly lower than the other expert estimates, and do not appear reasonable to us. At the same time, however, we are not persuaded that the medical inflation rates used by CVPS in its cost-of-service filings (14 percent for 2004, and 12 percent for 2005 and 2006) are appropriate either. While they are within the range of inflation rates provided by experts, and are less than the projected increases for the State of Vermont's two largest medical insurance plans, they are higher than the inflation rates included in the 2004 update of Towers Perrin's actuarial valuation, which the Company has relied upon in the preparation of previous financial disclosures.²⁸¹ We conclude that the updated Towers Perrin medical inflation rates are the appropriate rates to use in these proceedings — 12 percent in 2004, 11 percent in 2005, and 10 percent in 2006.

277. DPS Brief at 58.

278. Exh. DPS-Cross-8 at 1; Gamble reb. pf. at 39–40.

279. See finding 244, above, for a list of the other reasons.

280. Gamble pf. at 47–48.

281. Gamble reb. pf. at 38–39.

Therefore, we require CVPS to recalculate its medical expense for both rate years, taking into account: (1) the agreed-upon \$118,772 adjustment for the increase in employee medical insurance premiums from 2003 to 2004; (2) medical inflation rates of 12 percent in 2004, 11 percent in 2005, and 10 percent in 2006; and (3) the results of the Company's new contract with its union employees.

G. Director and Officer Liability Insurance

Findings

251. Director and Officer liability insurance protects shareholders from their own decisions regarding management of the company. Schultz and DeRonne pf. at 67–68.

252. Director and Officer liability insurance is a necessary cost of doing business for utility companies. A utility company must have Director and Officer liability insurance in order to attract capable people to serve as officers and directors. Deehan reb. pf. at 26.

Discussion

The DPS argues that since there is no identifiable benefit to ratepayers from Director and Officer liability insurance, the entire cost of that insurance should be removed from CVPS's cost of service.²⁸² Alternatively, if that recommendation is not accepted, the DPS asserts that the increase in premium between 2002 and 2003 should be removed, and the remaining balance shared 50/50 between ratepayers and shareholders.²⁸³

CVPS argues that the full amount of the Company's Director and Officer liability insurance should be allowed in its cost of service because it is a necessary aspect of providing service to consumers. The Company asserts that without Director and Officer liability insurance, CVPS will not be able to attract capable people to serve as the Company's officers and directors.²⁸⁴

282. DPS Brief at 65.

283. Schultz and DeRonne pf. at 69.

284. Deehan reb. pf. at 26.

While the DPS is correct that shareholders receive the direct benefits of Director and Officer liability insurance, we are persuaded by CVPS that such insurance is a necessary cost of doing business because without such insurance, CVPS would have a difficult time attracting quality officers and directors. For this reason, we conclude that Director and Officer liability insurance does have an indirect benefit to ratepayers that justifies requiring ratepayers to pay at least part of the cost.

However, Director and Officer liability insurance protects the Company as a whole, not just its regulated utility operations. As such, its costs should be shared by all portions of the Company, in proportion to the benefit each receives from the insurance. Since the Director and Officer liability insurance protects CVPS's shareholders from the actions of its management, we conclude that the best proxy for allocating the insurance's benefits among the Company's different operations is the allocation of CVPS's officers' time.

As discussed in Section VI.E.3, above, we determined that it was appropriate to charge 67.365 percent of CVPS's officers' time to regulated utility operations.²⁸⁵ Applying this same adjustment factor to CVPS's requested \$393,000 expense for Director and Officer liability insurance²⁸⁶ results in a disallowance of \$128,256 of the requested costs.²⁸⁷

H. Tree-Trimming

Findings

253. Falling trees (and tree limbs) are the number one cause of outages on CVPS's system and have the largest impact on overall system reliability. Every year approximately 2,500 tree-related outages occur. Outages caused by trees tend to be longer in duration because they usually cause significant damage. G. White pf. at 14-15.

285. CVPS allocated 74.85 percent of its officers' time to regulated operations and maintenance. We accepted the DPS's 10 percent reduction to that allocation. $0.7485 * 0.9 = 0.67365$ or 67.365 percent.

We recognize that the payroll allocation factor does not just separate costs between regulated and unregulated activities. Rather, it separates regulated operations and maintenance activities from regulated capitalized activities and unregulated activities. However, given CVPS's own statements that officers generally do not spend time on capital projects (Gibson reb. pf. at 29), we do not believe this significantly distorts the allocation factor.

286. Exh. DPS-L&A-11 at page 1 of schedule SR2.

287. $393,000 - (393,000 * 0.67365) = 128,256$

254. During the test year ending December 31, 2003, CVPS spent \$5,221,854 on tree trimming in distribution and transmission rights-of-way. Dickinson pf. at 3.

255. CVPS requested tree trimming expenses of \$6,284,444 in Rate Year 1 and \$6,466,224 in Rate Year 2. Dickinson pf. at 2-3.

256. CVPS's tree trimming expenses are increasing due to higher contractor fees which are a result of increased costs in fuel, labor, equipment and liability insurance. Dickinson pf. at 3.

257. Inspecting and treating poles before they become a public hazard and undermine system reliability is prudent. G. White pf. at 17.

258. CVPS requested pole treatment expenses of \$304,000 in Rate Year 1 and \$523,000 in Rate Year 2. Dickinson pf. at 3.

259. In order to maintain system reliability and ensure public safety, it is necessary to expend the full amount of the expected tree trimming and pole treating expenditures annually. Tr. 11/1/04 at 30 (Dickinson).

Discussion

Downed trees and tree limbs materially affect reliability and create safety hazards for CVPS employees and the public. Similarly, aged poles subject line workers and the public to unnecessary hazards that could be easily avoided by replacing those poles that show signs of structural deterioration.

CVPS and the DPS agree that maintaining a program of annually trimming trees and treating poles helps to ensure system reliability and safety. They disagree, however, on whether the Board should require the Company to spend all the funds requested for tree trimming and pole treatment each year, and to carry forward any unspent funds into the next year. The DPS asserts that the Board should impose this requirement, and should require CVPS to report its actual annual expenditures and amounts carried forward, compared to the amounts included in the Company's rates.

CVPS claims that the DPS's recommendation is one-sided, as it only addresses underspending of budgeted amounts and does not address what would happen if the Company spent more than the amounts included in rates.

Ensuring public safety and system reliability is a critically important task for CVPS. The amount that CVPS spends annually on tree trimming and pole treatment directly affects the Company's ability to remove potentially hazardous trees and replace aged poles.²⁸⁸ Without such attention to the condition of the rights-of-way and structural integrity of poles, CVPS's system reliability and safety could deteriorate. Therefore, we approve CVPS's request for tree trimming and pole treatment expenses, as stated in findings 255 and 258, above.

However, as we stated in our decision in a 1978 CVPS rate case:

In allowing the Company [tree trimming, pole treatment and overhead maintenance] costs, the Board expects that the funds approved be spent exclusively on these programs and within the time schedule to which the Company testified.²⁸⁹

Consistent with this long-standing expectation, in these proceedings we require CVPS to spend the entire amount included in rates for tree trimming and pole treatment each year on such activities. If CVPS is unable to do so, it should carry forward into subsequent years the amount of unspent funds. We also require CVPS to include in its annual reports filed pursuant to PSB Rule 4.903 the amounts spent for each of the above-mentioned programs, the amount to be carried forward into subsequent years, and a comparison of the amounts actually spent to the amounts allowed in rates. To the extent that CVPS spends more than the amounts allowed in rates in a given year, the Company may include the excess amounts as a credit toward the next year's spending so long as CVPS provides a detailed accounting, with supporting documentation, of the amount expended in excess of the amount collected in rates.

I. Cost Savings from Capital Additions

Findings

260. Capital additions to replace vintage mainframe tape technology (WO 6682), purchase a new network printer (Rutland WO 6778) and a so-called Tivoli Enhancement (WO 6782) will result in expected operating expense savings in both rate years. The net effect of these adjustments is \$81,250 and \$98,500 in Rate Year 1 and Rate Year 2, respectively. Schultz and

288. Tr. 11/1/04 at 30 (Dickinson).

289. Docket No. 4230, Order of 12/8/78 at 19.

DeRonne pf. at 72; Schultz and DeRonne sur. pf. at 16; Monder reb. at 11–12; exh. DPS-L&A-6 at schedule SR 22; exh. DPS-L&A-7 at schedule SR22.

261. CVPS's costs of service reflected cost savings associated with a video conferencing plant addition. This project resulted in cost savings of \$1,658 in Rate Year 2. As the video plant addition is not known and measurable (*see* Section V.A), these cost savings do not exist. Schultz and DeRonne sur. pf. at 17.

262. The net effect of these adjustments is \$79,592 and \$96,842 in Rate Year 1 and Rate Year 2, respectively. CVPS's regulated operating and maintenance expense should be adjusted to reflect these cost savings. Schultz and DeRonne sur. pf. at 16; Monder reb. at 11–12; exh. DPS-L&A-6 at schedule SR 22; exh. DPS-L&A-7 at schedule SR22.²⁹⁰

Discussion

CVPS and the Department agree that CVPS's cost of service should be reduced to reflect the cost savings from the three capital additions mentioned above. We conclude that these reductions are appropriate. If ratepayers are paying for capital additions, they should also benefit from any cost savings that result from these proposed capital additions. If, on the other hand, certain capital additions are disallowed, then the anticipated cost savings that were to be derived from the proposed capital addition should also be removed from the Company's cost of service. Consistent with these principles, we conclude that the agreed-upon cost adjustments shown in finding 260 above, are acceptable.

CVPS's cost-of-service filing included cost savings arising from the addition of new video conferencing equipment. In Section V.A, we conclude that CVPS has not demonstrated that its proposed plant addition is known and measurable. As a result, we need to reverse the cost savings that CVPS attributed to this plant addition. CVPS had reflected cost savings

290. The Department's uncontested testimony states that the effect of the cost savings from the video conferencing plant disallowance occurs in Rate Year 2 only. However, the Department's schedules reflect these savings in both Rate Years. See exh. DPS-L&A-6 at schedule SR 22. The Department's Brief also reflects this adjustment in the totals for both years. We assume that the Department's schedules and brief represent its position.

of \$1,658.²⁹¹ We accept the parties' recommendation that we offset the cost savings identified above by these costs savings that are not known and measurable.

J. Revenues

1. Unbilled Revenues

Findings

263. In its cost-of-service filings, CVPS used the actual, billed revenues from customers that occurred during the test year (calendar year 2003). CVPS did not include unbilled revenues, even though these revenues were earned by the Company. Schultz and DeRonne pf. at 39; Anderson reb. pf. at 2.

264. The difference between the Accrued Utility Revenues between December 31, 2002, and December 31, 2003 is \$777,387, which is the amount of unbilled revenues that CVPS excluded. Schultz and DeRonne pf. at 41.

265. Including these unbilled revenues would have no effect on the Company's revenue requirement, but would affect the percentage increase or decrease arising from this Order. Anderson reb. pf. at 2–3.

266. CVPS records its unbilled revenues, as required by GAAP. Tr. 1/12/05 at 37 (Gibson).

Discussion

In calculating the amount (and percentage) by which CVPS's rates should increase or decrease, we determine the Company's revenue requirement and then compare that figure to the Company's test year revenues. As a result, any adjustments to the test year revenues have a direct effect on the final rate levels.

In its cost-of-service filing, CVPS reflected the actual, billed revenues from customers that occurred during the test year.²⁹² These billed revenues do not, however, reflect all of the actual revenues earned from regulated operations during 2003. Rather, CVPS also earned \$777,387 in unbilled revenues that the Company excluded from its revenue totals.²⁹³

291. CVPS witness Monder testified that the savings were actually \$6,630. Monder reb. pf. at 9. However, in its Reply Brief, CVPS accepts the Department's figure of \$1,658. CVPS Reply Brief at 206.

292. Anderson reb. pf. at 2.

293. Schultz and DeRonne pf. at 41.

The Department argues that we should adjust CVPS's cost-of-service filing to reflect the unbilled revenues. According to the Department, CVPS's filing, by excluding these revenues, does not reflect the actual calendar-year 2003 revenues from regulated operations.²⁹⁴ The Department asserts that ignoring the unbilled revenues would "ignore sales that have occurred." It also, the Department maintains, would result in a mismatch of revenues and expenses by including the costs associated with producing the revenue while excluding the resulting revenue.²⁹⁵

CVPS takes the position that its approach is consistent with past ratemaking conventions in that the Board had not previously adopted an adjustment for unbilled revenues. The Company suggests that the Department has selectively reversed its position on these revenues simply to justify lower rates.²⁹⁶ CVPS also states that the unbilled revenues only reflect estimates based upon kWh sales, not all of the time-of-day kWh and kW elements of the Company's rate structure, so that the amount of unbilled revenues is not precise.²⁹⁷

We accept the Department's recommendations and direct CVPS to adjust the test-year revenues to include the unbilled revenues that it originally excluded. Inclusion of unbilled revenues will mean that the revenues used for determining the rate changes are based upon actual sales to customers that occurred during the historic test year.²⁹⁸ This resolution is also consistent with our previous rulings on the issue.²⁹⁹

We recognize that we have not made such an adjustment for CVPS in prior cases. That fact alone is not sufficient basis for failing to take into account revenues where the evidence demonstrates that CVPS earned the revenues during the test year. Moreover, as the Department has argued, adjusting revenues to reflect the unbilled revenues that CVPS earned also better matches the revenues with the underlying expenses. CVPS's cost of service is based upon its

294. DPS Brief at 47–48.

295. *Id.* at 48.

296. CVPS Brief at 346.

297. CVPS Reply Brief at 165; Anderson reb. pf. at 3–4.

298. Schultz and DeRonne sur. pf. at 47.

299. *Tariff filing of Citizens Communications Company, d/b/a Citizens Energy Services*, Docket 6596, Order of 7/15/02 at 91–94.

expenses during calendar year 2003 (the test year). The Department's adjustment aligns the revenues with these costs.

Finally, we reject CVPS's assertion that it is unfair to adjust for unbilled revenues now when they serve to increase the test year revenues. Our task here is to determine the appropriate rate treatment based upon the evidence before us, which shows that CVPS received these revenues. As CVPS acknowledged, an adjustment for unbilled revenues can be either positive or negative.³⁰⁰ We would expect to recognize adjustments to revenues (whether positive or negative) in the future.

2. Cable Television Pole Attachment Revenues

Findings

267. CVPS collects pole attachments fees from telephone companies and third-parties, including cable television ("CATV") companies. CVPS also pays attachment fees to telephone companies for attachments of CVPS wires on telephone facilities. Anderson pf. at 3.

268. Pole attachment revenues received by CVPS are shown as a credit in the cost-of-service. The revenue for each attachment is based upon the actual number of jointly-owned and solely-owned poles (as of December 31, 2003) and whether the attaching company uses two feet of space (Tariff 2) or one foot (Tariff 1). Anderson pf. at 3; Schultz and DeRonne pf. at 61; Anderson reb. pf. at 6.

269. The two-foot rate is twice the one-foot rate. Anderson reb. pf. at 7.

270. CVPS has billed Adelphia at the two-foot rate. If these pole attachments were priced at the one-foot rate, the revenues would be reduced by \$373,085 in both Rate Years 1 and 2. Anderson reb. pf. at 8.

271. CVPS has set aside reserves of \$447,100 on its books to reflect the expectation that the Board will require it to charge CATV providers at the one-foot rate and to otherwise reduce its pole attachment rates in Docket 6605. Anderson pf. reb. at 7–9; tr. 11/3/04 at 253 (DeRonne).

300. Tr. 1/12/05 at 158–159 (Gibson).

Discussion

CVPS derives revenues from companies that attach to the poles that CVPS owns, including jointly-owned poles. A substantial portion of the pole attachment revenue is from cable television companies. CVPS also pays attachment fees to telephone companies when it attaches its own wires to the telephone companies' poles.³⁰¹ The pole attachment revenues exceed the costs and provide a credit to the Company's cost of service.

In preparing its cost-of-service filings, CVPS made a preliminary calculation that CATV pole attachment revenues were \$866,585.³⁰² CVPS then made two adjustments to this figure, reducing the amount to \$419,475. These adjustments reflect the Company's expectation that CATV payments will decline as a result of the Board's investigation into CVPS's pole attachment rates (Docket 6605). First, CVPS expects that the Board will only require CATV providers to pay for one foot of space on the pole as opposed to the two-feet rate that CVPS generally charges, reducing revenues in both rate years by \$373,085. Second, CVPS assumes a further downward adjustment of \$74,025 in both rate years due to an expectation that the Board will lower the pole attachment rates themselves.³⁰³ CVPS has recorded a reserve on its books based upon these expectations, which it asserts is required by GAAP.³⁰⁴ CVPS asserts that, unless the Board makes the adjustments proposed by CVPS, the Company will not have a fair opportunity to earn its return if the ruling in Docket 6605 is adverse. Finally, CVPS states that the Board can take steps in Docket 6605 to protect the interest of customers if the Board rejects CVPS's position in that case.³⁰⁵

The Department opposes both adjustments. According to the Department, it is not known and measurable that either of the outcomes CVPS expects will occur.³⁰⁶ The Department points out that CVPS has continued to bill its CATV attachers at the higher rate.³⁰⁷ Instead, the

301. Anderson pf. at 3.

302. Anderson reb. pf. at 6; Schultz and DeRonne pf. at 61.

303. CVPS Brief at 342; Anderson reb. pf. at 8; Schultz and DeRonne pf. at 61–62.

304. Anderson pf. reb. at 7–9.

305. CVPS Brief at 343.

306. Schultz and DeRonne pf. at 62.

307. Schultz and DeRonne reb. pf. at 48.

Department asks that, until Docket 6605 is resolved, the test year billed revenues from CATV pole attachments should be included in CVPS's rates.³⁰⁸

The Department's assertions concerning reliance upon the potential outcome of Docket 6605 have some merit. At the present time, we conclude that CVPS's adjustments are not known and measurable.³⁰⁹ With the resolution of Docket 6605 unknown, we cannot know if CVPS will prevail on any or all of its arguments. Moreover, because of this uncertainty, it is impossible to measure the proposed adjustment to the test year revenue levels. CVPS's decision to record a reserve on its books for the potential loss of revenue does not convert the uncertainty into a known and measurable change. The result and magnitude of the financial impact are still unknown.

We understand that the timing of Docket 6605 and this proceeding means that, if we do not reflect the revenue adjustment CVPS proposes and the Company ultimately loses its pole attachment argument, CVPS may earn less than it would if we accepted the adjustment. The known and measurable standard notwithstanding, CVPS has proposed that we allow its adjustment and then take action in Docket 6605 to protect the interests of consumers. If we can assure that ratepayers could be fully protected from paying rates based upon CATV revenue reductions that do not occur, we could allow CVPS's adjustment now. To achieve this result, the difference between the pole attachment revenues we allow in rates for both periods and the revenues that would derive from using the same billing determinants but applying the conclusions in Docket 6605 would need to flow back to ratepayers.

CVPS did not specify how the Board could legally achieve this result, although we see two possible approaches. First, we could issue an accounting order requiring CVPS to track the difference between the amount of revenue we include in rates and the revenue collected based upon the final ruling. Such a decision would have the adverse effect of continuing the practice of using accounting orders for events that are not truly extraordinary. As we explain elsewhere in

308. DPS Brief at 60.

309. Significantly, CVPS does not argue that the adjustment it proposes is known and measurable. Instead, CVPS relies upon the other arguments described above.

this Order, it would be preferable to limit the use of accounting orders to events that are consistent with GAAP's description of what constitutes an extraordinary event.

A second approach, which we adopt, would require CVPS, as part of its compliance filing in this docket, to submit a specific proposal to protect the interests of consumers following any final order in Docket 6605. CVPS's proposal should ensure the difference in CATV revenues (including the effect of any possible retroactive adjustment) is returned to ratepayers in a timely fashion. If CVPS elects not to propose such a mechanism (consistent with Vermont law), we cannot conclude that CVPS's adjustment is known and measurable. In this case, CVPS's compliance filing should not include the adjustment to the CATV revenue proffered by the Company.

Finally, we are concerned about the Company's apparent inconsistency in this proceeding. On the one hand, CVPS says that it is sufficiently likely to lose the CATV case that it must record a loss on its books.³¹⁰ If the likelihood of success is as dim as CVPS seems to suggest, it is not clear why it is reasonable to charge ratepayers for the cost of litigating what CVPS now characterizes as a losing position. We will consider this issue in CVPS's next rate proceeding. At present, we can only infer from CVPS's continued litigation that it views its prospects for success more favorably than its current position — and the booking of a reserve — would suggest, in which case the Department's argument carries greater weight.

K. Agreed-Upon Adjustments

Findings

272. The \$3,500 that CVPS paid for the production and distribution of a video entitled "Patriotism and You" should be removed from the costs of service for both Rate Years 1 and 2. Schultz and DeRonne pf. at 75; Gibson reb. pf. 11/15/04 at 30.

273. Safety training costs for Rate Year 1 should be increased \$9,000. Safety training costs for Rate Year 2 should be increased \$8,000. Schultz and DeRonne pf. at 67; exh. CVPS-4.

310. By contrast, in the hearing on CVPS's request for an accounting order in these dockets, CVPS took the position that the outcome of the instant cases could not be reasonably quantified.

Discussion

CVPS and the DPS have agreed on two miscellaneous adjustments.³¹¹ For the reasons explained below, we conclude that the adjustments are appropriate, and we hereby accept them. First, the Board has long held that shareholders, not ratepayers, should pay for utility companies' charitable and community service activities. Consistent with this policy, the costs associated with the "Patriotism and You" video should be charged to shareholders, not ratepayers. Second, the adjustment to safety training costs corrects an error made by CVPS in its original filing — it had reflected the discount offered rather than the projected costs.

VII. COST OF CAPITAL

Findings

274. CVPS's capital structure, rates for each capital component of the capital structure and weighted average cost of capital for Rate Year 1 is shown in the table below.

Description	Ratio	Cost Rate	Weighted Average Cost of Capital
Long Term Debt	40.29%	7.29%	2.94%
Preferred Equity	5.10%	6.43%	0.33%
Common Equity	54.61%	10.00%	5.46%
Total	100.0%		8.73%

Exh. DPS-L&A-11, Schedule SR4; Talbott and Roschelle pf. at 8.

275. CVPS's capital structure, rates for each capital component of the capital structure and weighted average cost of capital for Rate Year 2 is shown in the table below.

311. In addition, CVPS and the DPS agreed that a \$31,000 adjustment to the costs of service for both Rate Years 1 and 2 that was originally proposed by the DPS should *not* be made. The \$31,000 was the amount of a penalty that CVPS paid as a result of the Board's decision in Docket 6758 (*Investigation into Fourteen Utilities' Provision of Service to Customers Pursuant to Expired Special Contracts or at Special Rates Without Board Approval*). The DPS originally stated that the penalty was inappropriately included in the filed costs of service, but later agreed with CVPS that the penalty was not included. Schultz and DeRonne pf. at 74; Gibson reb. pf. 11/15/04 at 30; Schultz and DeRonne sur. pf. at 49.

Description	Ratio	Cost Rate	Weighted Average Cost of Capital
Long Term Debt	39.75%	5.77%	2.29%
Preferred Equity	4.72%	6.31%	0.30%
Common Equity	55.53%	10.00%	5.55%
Total	100.0%		8.14%

Exh. DPS-L&A-12, Schedule 4; Talbott and Roschelle pf. at 8.

276. An allowed return on equity of 10 percent adequately compensates investors, given the level of perceived risks in CVPS's business. Talbot and Roschelle pf. at 5; tr. 11/5/04 at 45–46 (Talbot and Roschelle).

277. The 10-year Treasury bond yield currently ranges between 4 and 5 percent, the lowest level in over 40 years. Woolridge pf. at 2.

278. Capital costs, including equity costs, for U.S. corporations are at their lowest levels since the 1960's. Talbot and Roschelle pf. at 6; Woolridge pf. at 2.

279. CVPS's common and preferred equity ratio is 60 percent, approximately 20 percent higher than the equity ratios of other similarly-situated electric utilities. Exh. DPS-JRW -3.

280. The use of accounting orders which defer the recovery of prudently incurred, but unexpected, increases in purchased power is viewed by the investment community as an adequate substitute for purchased power adjustment clauses. Exh. DPS-Cross-19.

281. The Company's purchased power strategy reduces operational risk and minimizes its capital expenditure requirements. Exh. DPS-41; exh. DPS-Cross 22 at 17.

282. By purchasing a substantial amount of its power commitments under fixed long-term contracts, CVPS reduces its exposure to wholesale electric price volatility under FERC's Standard Market Design ("SMD"). Exh. DPS-Cross-26.

283. CVPS's bond ratings have been affirmed by Standard & Poor's (BBB-) and upgraded by Fitch (BBB+), in part, because of the improving regulatory climate in Vermont, a diverse customer mix, low operating risks, and interest coverage ratios commensurate with the ratings

category. Exh. CVPS-JCC-12; exh. DPS-45; exh. CVPS-5 at 40 (2001 CVPS Annual Report); exh. CVPS-7 at 48 (2003 CVPS Annual Report).

284. CVPS has a demonstrated history of strong, stable cash flows and moderate financial leverage. Exh. DPS-Cross-22 at 16.

285. CVPS benefits from operating in Vermont because retail competition has not been approved, therefore the risk of bypass has been essentially eliminated. Exh. DPS-Cross-22 at 16.

286. CVPS benefits from customer diversity as its five largest customers represent only 5 percent of the Company's total electric revenue. Exh. CVPS-10 at 2.

287. CVPS is a traditional, regulated electric utility company which operates in a relatively low-risk business characterized by secure, predictable cash flows and solid capitalization. Exh. DPS-Cross-22 at 17.

288. Investors regard the stocks of smaller companies to be slightly more risky than the stocks of companies with larger capitalization due to the lack of liquidity.³¹² Talbot and Roschelle pf. at 11; tr. 11/5/04 at 65 –66 (Talbot and Roschelle).

289. As of September, 2003, CVPS had a market capitalization of approximately \$250 million. Talbot and Roschelle pf. at Schedule 2a.

290. CVPS has approximately 12.25 million shares outstanding, of which 5.5 million shares are owned by institutions. Woolridge sur. pf. at 3.

291. Approximately 5 percent of CVPS's outstanding shares (roughly 612,500) trade on a monthly basis. Woolridge sur. pf. at 3.

292. CVPS was ranked first in the nation in the Edison Electric Institute's 2003 index for five-year shareholder returns, providing shareholders a 205 percent return.³¹³ Talbot and Roschelle pf. at 7.

312. Liquidity refers to the ability of stockholders to buy and sell shares of a particular company in a timely manner. Woolridge sur. pf. at 3.

313. The index includes changes in stock prices and dividend re-investments for the period from January 1, 1999, to December 31, 2003.

Discussion

There are three essential steps in setting the weighted average cost of capital. First, we determine an appropriate capital structure. Second, we determine the cost of each capital component. Third, we determine the cost of each capital component according to its proportion of the total capital structure. The sum of these weighted capital components is the weighted-average cost of capital. In these proceedings, the capital structure and the costs of preferred equity and debt are not in dispute.

While debt is less expensive than equity, there are limits to the amount of debt that can be used to finance utility operations before equity investors begin to demand higher returns. Therefore, an appropriate amount of equity is necessary to minimize overall capital costs. Based on the record evidence and agreement between the parties, we find that it is appropriate to use a capital structure in Rate Year 1 consisting of 40.29 percent long-term debt, 5.10 percent preferred equity and 54.61 percent common equity. For Rate Year 2, we find that it is appropriate to use a capital structure consisting of 39.75 percent long-term debt, 4.72 percent preferred equity and 55.53 percent common equity. We conclude, based on the record, that long-term debt and preferred equity costs in Rate Year 1 are 7.29 percent and 6.43 percent, respectively. In Rate Year 2, we conclude that long-term debt and preferred equity costs are 5.77 percent and 6.31 percent, respectively.

In these proceedings, the parties disagree on the appropriate return on equity. CVPS, the Department and AARP recommend returns on equity of 11.0 percent, 8.75 percent and 10.0 percent, respectively. Based on the record evidence, we conclude that a return on equity of 10.0 percent appropriately compensates investors for the level of risk they may encounter by holding CVPS stock. Authorizing a 10.0 percent return on equity provides CVPS with the opportunity to generate risk-adjusted returns that are comparable to the potential returns of similarly-situated electric utilities. It also assures CVPS's investors that the Company will remain financially sound and have the ability to raise additional capital, if necessary.

We recognize that we are authorizing a different return on equity in these proceedings than we recently authorized for GMP (10.50 percent) and Vermont Gas Systems, Inc. ("Vermont

Gas") (10.98 percent).³¹⁴ Each time we determine a company's return on equity, we consider that company's particular situation. Our decisions regarding GMP and Vermont Gas reflect the circumstances facing those companies, circumstances that do not apply to CVPS. In GMP's case, roughly 20 percent of its retail revenues are generated from a single industrial customer. With such a concentration of revenues in one large industrial customer, we have no trouble concluding that investors perceive GMP as more vulnerable than CVPS. With regard to VGS, the Board authorized a 10.98 percent return on equity as an incentive to investors to assume greater risk for building out VGS' transmission pipe system into areas of Vermont that are currently unserved.

CVPS asserts that the cumulative effect of a series of company-specific risks warrant an 11.0 percent return on equity. These risks include the lack of a purchase power adjustment ("PPA") clause, FERC's Standard Market Design ("SMD") rules, negative perceptions of the investment community, incomplete implementation of a performance-based regulatory regime and the discontinuance of the Account Correcting for Efficiency ("ACE") mechanism. CVPS argues that the Board must also consider the effects of the DPS's proposed cost-of-service adjustments may have on investors' perceptions of CVPS's ability to earn a reasonable return on their investment.³¹⁵ We address each of CVPS's assertions below.

Purchase Power Adjustment Clause

Purchase power adjustment clauses provide utilities with the ability to flow through increases or decreases in the cost of power directly to retail customers in between rate investigations. Vermont Supreme Court precedent prohibits the use of PPA clauses as such flow-through mechanisms are inconsistent with the customer notice requirements of 30 V.S.A. § 225.³¹⁶ Accordingly, CVPS claims that a higher return on equity of 11.0 percent is appropriate. To support its argument that investors are demanding a higher return on equity, CVPS relies on a portion of a Standard & Poor's report that states:

Although short-lived the [Vermont Yankee Nuclear Power Plant] outage underscores one of the potential vulnerabilities that Vermont's [Investor

314. Docket 6867, Order of 12/23/03 at 42 (order paragraph 6); Docket 6829, Order of 10/7/2003 at 4.

315. CVPS Reply Brief at 229.

316. *In re Allied Power & Light Co.*, 132 Vt. 354 (1974).

Owned Utilities] face in a long-term outage. Neither utility (i.e. CVPS and GMP) has access to an automatic fuel and purchase adjustment clause.³¹⁷

However, after reviewing the entire Standard & Poor's report, we reach a different conclusion than CVPS. Rather than advising investors to either demand higher returns on equity or sell their Vermont-based holdings, the report, instead, informs investors that both CVPS and GMP have the ability to obtain timely redress in the form of accounting orders in the absence of a PPA. As we explain above in Section IV, this Board has issued accounting orders due to extraordinary events. The report also provides investors with assurances that because CVPS has ample cash reserves and access to capital, the potential risk posed by Vermont's PPA prohibition is offset. The Company's diverse customer mix, stable load growth and low operating risks mitigate the amount of potential risk associated with the lack of a PPA.

We also note that the Company, in its private placement memorandum to investors, downplayed the effects, if any, of Vermont's lack of a PPA. In the memorandum, CVPS stated that:

The company recognizes that adequate and timely rate relief is required to maintain financial strength, particularly since Vermont law does not allow power and fuel cost to be passed to consumers through a fuel adjustment clause. The company will continue to review costs and request rate increases when warranted.³¹⁸

The positive attributes of CVPS's diverse customer mix, low operating risks and long-term fixed-priced purchase power contracts offset any additional risks facing CVPS as a result of the PPA prohibition.

Standard Market Design

CVPS contends that FERC's SMD rules create new uncertainty due to increased volatility in wholesale power costs even for load serving entities who have secured all of their power resource requirements through fixed-price contracts.³¹⁹ The SMD rules, according to CVPS, have also created uncertainty in the wholesale ancillary services market, such as operating

317. Exh. DPS-Cross-19.

318. Exh. DPS-Cross-22 at 24.

319. CVPS Brief at 19.

reserves. As an example of these additional risks in the operating reserves market, CVPS points to its experience during an extreme cold weather pattern in January, 2004. According to CVPS, the Company incurred extraordinary expenses over a three-day period when operating reserve charges increased dramatically due to short supplies of natural gas.³²⁰

In response, the DPS claims that CVPS has overstated the SMD-related risks, if any. To the extent such risks do exist, the DPS contends that electric utilities are accustomed to mitigating their impact.³²¹ The DPS notes that CVPS mitigates such risks by procuring a substantial portion of its power requirements under long-term contracts. As a result, the DPS asserts that most of CVPS's power purchases are not subject to large price swings.

The DPS also contends that, contrary to CVPS's assertions that these risks are meaningful, the bond rating agencies discount them. The DPS states that SMD-related risks actually received little to no attention in the investment analyst reports that CVPS submitted into the record.³²² Rather than express specific concerns over SMD rules, according to the Department, these same reports listed a series of positive attributes which enhance CVPS's credit rating such as regulatory support for supply cost recovery, the sale of Vermont Yankee, increases in operating efficiencies, and adequate capitalization ratios.³²³

We conclude that CVPS has overstated the concerns of the investment community with regard to the potential impact SMD rules may have on investor returns. FERC's SMD rules are not specific to CVPS.³²⁴ Similar rules apply to investor-owned electric utilities in most of the United States. Thus, there is no basis for assigning to CVPS an additional risk premium compared to other electric utilities. In addition, CVPS purchases a substantial portion of its power under long-term contracts, the cost of which we are allowing to be recovered from ratepayers. Therefore, most of CVPS's power purchases are not affected by the volatility of the regional wholesale power market.³²⁵ And, while CVPS is exposed to weather-related spikes in

320. CVPS Brief at 19–20.

321. DPS Brief at 92, 94.

322. DPS Brief at 94.

323. DPS Brief at 94.

324. Tr. 11/4/04 at 249 (Cater).

325. Exh. DPS-Cross-26 at 59.

operating reserve charges, there are opportunities to offset these costs by selling excess power into the wholesale market at favorable prices.

Perceptions of the Investment Community

CVPS contends, that as a result of past decisions issued in 1998 regarding the recovery of Hydro-Québec power costs, the investment community perceives Vermont as a difficult jurisdiction. Past Board decisions, according to CVPS, are viewed as inconsistent and at odds with stockholders' interests. CVPS argues that such inconsistencies lead to the conclusion that investors should be allowed to earn a higher rate of return. To improve its image and dispel these negative perceptions, CVPS contends that it is necessary for this Board to authorize an 11.0 percent return on equity.

Pointing to the same investment analyst reports that CVPS relies upon, the DPS claims that investment analysts have a positive view of the regulatory environment in Vermont.³²⁶ Additionally, the DPS states that despite the Company's assertions in this proceeding regarding negative perceptions of regulation in Vermont, CVPS portrayed a positive and improving regulatory environment in a recently issued Private Placement Memorandum.³²⁷

CVPS's assertions regarding the investment community's negative perceptions of Vermont are unsupported by the record evidence and inconsistent with statements the Company has made to the investment community. Investors clearly consider CVPS's stock to be a solid investment, in fact it ranked first among all investor-owned utilities in the United States in the 2003 Edison Electric Institute's index for total shareholder returns over the five-year period ending December 31, 2003. Investors who purchased CVPS stock on January 2, 1999, earned a cumulative return of 205 percent by the end of 2003. Compared to a -3.0 percent cumulative return for the S&P 500 index over the same period, CVPS investors were clearly compensated well for the risks they assumed.³²⁸ Additionally, at the end of 2004, Fitch IBCA, a credit rating

326. DPS Brief at 91.

327. In connection with the issuance of \$75 million first mortgage bonds, CVPS issued a Private Placement Memorandum to generate investor interest and solicit CVPS bonds.

328. Talbot and Roschelle pf. at 7; exh. CVPS-10 (2003 CVPS Proxy Statement at 15).

agency, upgraded outstanding CVPS bonds from BBB to BBB+ and considered the Company's outlook to be positive.³²⁹

We also note that CVPS's own statements to the investment community in its \$75 million private placement memorandum are inconsistent with the Company's assertions in this proceeding. In that Memorandum, CVPS characterized its operations as "relatively low risk" with "secure, predictable cash flows and solid capitalization" which are the result of a regulated rate structure that has produced "stable EBITDA"³³⁰ and "strong interest coverage ratios."³³¹ In addition, CVPS's cost of capital witness testified that the investment community's perceptions of Vermont were improving.³³² Based on the record evidence, we find CVPS's assertions in these proceedings to be inconsistent with its own statements to potential investors, and therefore, unpersuasive. Due to the recent bond rating upgrades and the cumulative five-year returns on CVPS stock compared to other investor-owned utility stocks, we can only conclude that the investment community has a favorable opinion of the Vermont regulatory environment.

SERVE Plan

According to CVPS, the current SERVE³³³ plan is the functional equivalent of a partial Performance-Based Regulation plan ("PBR"). CVPS states that it could, however, be reasonably viewed as a step toward the creation of a more complete plan since performance standards and the risk of financial penalties for poor customer service are important features of a PBR mechanism as well as for CVPS's SERVE plan.³³⁴ Despite the similarities, CVPS asserts that the current SERVE plan imposes extra risks in the form of financial penalties for poor customer service but does not include the financial incentives for exceptional performance that other, more

329. Exh. DPS-45 (Fitch Press Release, December 14, 2004.); exh. CVPS-5 at 56 (2001 CVPS Annual Report); exh. CVPS-7 at 48 (2003 CVPS Annual Report).

330. EBITDA stands for Earnings Before Interest, Taxes, Depreciation and Amortization expenses.

331. Exh. DPS-Cross-22 at 17. We note here that in fairness that the May, 2004 Memorandum predates the submission of the Department's prefiled testimony on October 1, 2004.

332. Tr. 11/4/04 at 225 (Cater).

333. "SERVE" stands for Serving Everyone with Reliability, Value and Excellence. Established in October, 2003, the SERVE plan represents the Company's Service quality and reliability plan. G. White pf. at 3.

334. CVPS Brief at 22.

complete PBR plans provide.³³⁵ According to CVPS, there are more down-side risks inherent in the current SERVE plan than up-side risks, therefore, investors should be allowed to earn a higher return on equity.

The DPS claims that CVPS has overstated the alleged down-side risks of the current SERVE plan. Similar to the alleged SMD concerns mentioned above, the DPS points out that investment analysts made no specific statement related to the current SERVE plan in the investment reports that CVPS entered into the record.³³⁶

Based on the record evidence, we conclude that CVPS's SERVE plan does not impose upon the Company any additional risks that could not be readily offset. The record evidence clearly indicates that any potential down-side risks, if they exist at all, associated with the SERVE plan have been offset by other positive attributes of CVPS's operations such as low operating risks, stable EBITDA and secure, predictable cash flows.

Account Correcting for Efficiency

These proceedings are the first earnings investigation since the discontinuance of the Account Correcting for Efficiency ("ACE"), a mechanism that provided the Company with a method of recovering net revenue losses resulting from system-wide demand-side management measures implemented by the Energy Efficiency Utility ("EEU"). As a result, CVPS asserts that an 11.0 percent return on equity is warranted because the elimination of ACE revenues exposes the Company to the risk that its earnings will erode.³³⁷ According to CVPS, as long as the unit price of providing electric service exceeds marginal cost, the loss of the ACE revenues adversely affects the Company's financial performance.³³⁸

In response, the DPS asserts that the elimination of the ACE mechanism does not impose any additional risk on investors. Similar to CVPS's assertions related to the perceived amount of additional risks related to SMD and the SERVE plan, the elimination of the ACE mechanism was not specifically mentioned in the investment analyst reports submitted by the Company.

335. CVPS Brief at 22

336. DPS Brief at 93–94.

337. Cater pf. at 14.

338. Cater pf. at 14–15.

The record evidence does not support CVPS's contentions that elimination of the ACE mechanism has increased risks. CVPS made no explicit reference to the elimination of the ACE mechanism in its Private Placement Memorandum to investors even though that document was issued in May, 2004, nearly 12 months after ACE was discontinued. Given the lapse in time, CVPS should have been fully aware of the financial implications of the ACE phase-out, if any, at the time it issued its Memorandum. Had there been a significant financial impact, then CVPS would have been obligated to disclose the nature of these potential impacts and fully describe the attending risks that the elimination of ACE would have presented to investors. The fact that the company did not specifically raise the issue in its Memorandum suggests to us that CVPS believes that the discontinuance of ACE is a non-material event.

Contrary to CVPS's opinion that the discontinuance of the ACE mechanism exposes the Company to the potential risk of earnings erosion, we conclude that it is more likely that CVPS will actually benefit from system-wide energy efficiency measures. The EEU's efforts result in less energy consumption by CVPS customers. As a result, the company is able sell more excess power into the wholesale market at favorable rates. Such actions improve the financial performance of the Company, rather than impair it.

Liquidity Risk

Investors in companies with small market capitalizations are typically exposed to additional risks as a result of their inability to consummate large stock transactions in a timely manner.³³⁹ CVPS is considered to be a small capitalized ("small-cap") company.³⁴⁰

The DPS asserts that while CVPS is considered to be a small-cap company, there is no empirical evidence to support the contention that investors do in fact demand an extra liquidity risk premium. In the DPS's opinion, there is no basis for increasing its return on equity recommendation of 8.75 percent until CVPS has presented evidence of a liquidity premium.

Investors' expected returns are not readily observable. It has been a long-standing regulatory practice to infer the amount of future expected returns by examining forecasted growth

339. Woolridge sur. pf. at 3.

340. Talbot and Roschelle pf. at 13.

rates of similarly-situated companies and the level of risks these companies are expected to encounter. Similarly, the amount of liquidity risk that investors assign to small-cap stocks is unobservable. Therefore, we must also infer the amount of this type of risk.

The market capitalization of the list of similar-situated companies analyzed by AARP is as follows:³⁴¹

Company	Market Capitalization (\$ Millions)
Avista	850
CVPS	250
Green Mtn Power	125
MGE	575
Otter Tail	690
Vectren	1,900
WPS	1,700
Average	870

There are 12.25 million CVPS shares outstanding, of which approximately 45 percent are held by institutions who are more likely to place larger orders than non-institutional owners.³⁴² CVPS's market capitalization is approximately 28.7 percent of the mean average of the above-captioned companies. On this evidence, we conclude that CVPS investors face an additional risk compared to the investors of the other electric companies in the above-captioned group because of a perceived liquidity risk. The market capitalization of the Company is smaller than the other companies and a large percentage of the Company's stock are held by institutional investors who are inclined to trade relatively large blocks of stocks. It is, therefore, appropriate to increase the Company's return on equity above the recommendation of the DPS as compensation.³⁴³

341. Talbot and Roschelle pf. at schedule 2a.

342. Woolridge sur. pf. at 3.

343. We note that GMP is also a small-cap stock for which we authorized a return on equity of 10.5 percent in Docket 6867. As stated earlier, our authorization of a 10.5 percent return on equity was based on a different set of facts and circumstances that do not apply to CVPS.

Basis for Decision

As with countless other rate cases before this Board, our decisions are guided by the law and regulatory precepts that have evolved over the last 100 years. These proceedings are no different. And, in spite of the changing nature of the law and regulation, our unwavering goal is to strike a balance between the interests of ratepayers who desire low-cost reliable service and investors who hope to maximize their returns on invested capital.

The DPS, AARP and CVPS have recommended returns on equity of 8.75 percent, 10.0 percent and 11.0 percent, respectively. All of the recommendations were based on analyses using traditional methodologies³⁴⁴ of estimating required returns. Two of the three parties also relied, in part, on recently authorized returns on equity in other jurisdictions. The DPS's recommendation of 8.75 percent was predicated on the proposition that risk premiums were shrinking.

Neither the law nor regulatory precepts prescribe a methodology for setting the appropriate return on equity. All that is required of us, is to authorize a return on equity that is fair and reasonable to all stakeholders. It is not necessarily the method used to establish an appropriate return on equity that is important but the end result.³⁴⁵ We conclude that adopting the DPS' recommendation would result in an unfair decision based on an unproven supposition that fails to strike a balance between the interests of ratepayers and investors. Therefore, we reject the DPS's recommendation. Instead, we conclude that, based on the record evidence, a return on equity of 10.0 percent provides CVPS with the opportunity to generate risk-adjusted returns that are comparable to similar-situated companies and assures the financial soundness of the Company.

344. These methods were the Discounted Cash Flow, Capital Asset Pricing methodology and historical risk premium methodology.

345. *In re FPC v. Hope Natural Case Co.*, 320 U.S. 591, 602 (1944).

VIII. OTHER ISSUES

A. Treatment of Regulated Affiliates

Findings

293. CVPS owns interests in affiliates that are subject to the jurisdiction of FERC. These "regulated affiliates" are:

- the Vermont Electric Power Company ("VELCO");
- the Vermont Yankee Nuclear Power Corporation ("VYNPC");
- Connecticut Yankee;
- Maine Yankee; and
- Yankee Atomic

(the last four, collectively, are often referred to as "the Yankees"). Gibson pf. at 28; exh. CVPS-7 at 29–31.

294. CVPS owns 50.5 percent of VELCO's outstanding common stock. Exh. CVPS-7 at 30.

295. CVPS has a 58.85 percent ownership interest in VYNPC. *Id.*

296. CVPS has a 2 percent ownership interest in Maine Yankee, 2 percent ownership interest in Connecticut Yankee, and 3.5 percent ownership interest in Yankee Atomic. *Id.* at 31.

297. Vermont's consistent ratemaking treatment for decades has been to consider both investments and returns on rate-regulated affiliates above-the-line in a Vermont utility's cost of service. This means that equity investments, income, and tax effects of regulated affiliates are traditionally included in cost-of-service filings. Behrns sur. pf. at 16; Behrns pf. at 12.

298. CVPS proposes that past precedents be changed and that it now be allowed to treat its regulated affiliates below-the-line for ratemaking purposes. In CVPS's cost-of-service filings in these proceedings, the investments in the affiliates were removed from the Company's rate base, equity earnings in the affiliates was not credited, and there was no deduction for equity earnings of these affiliates in the income tax calculation. Gibson pf. at 27 –28; Frankiewicz pf. at 21; Behrns pf. at 12.

299. The treatment of the regulated affiliates proposed by CVPS represents a change in the treatment previously afforded such affiliates in the Company's prior rate cases over many years,

as well as in this Board's consistent treatment of other investor-owned utilities in Vermont. Deehan reb. pf. at 20; Behrns pf. at 11.

300. At present, the FERC-approved returns on equity for the Yankees are less than the Company's current allowed return on equity on its Vermont utility operations. The FERC-approved return on equity for VELCO is currently higher than the Company's current allowed return on equity on its Vermont utility operations. CVPS responses to Board's 1/24/05 Memorandum, dated 2/2/05, at Attachment PSB 2-1A.

301. Above-the-line ratemaking treatment for affiliates whose allowed return on equity is greater than CVPS's allowed return on equity, in general, decreases CVPS's overall retail revenue requirement. The converse is also true. Behrns sur. pf. at 16; tr. 1/13/05 at 178–180.

302. The effect of the established ratemaking treatment of the Yankees, generally, represents an increase to the Company's revenue requirement. Conversely, treating VELCO similarly reduces the Company's retail revenue requirement. Behrns pf. at 12.

303. Historically, costs for CVPS's decommissioning obligations for the Yankees were recovered in rates. Behrns sur. pf. at 16.

304. CVPS's costs for services provided by VELCO are recovered in rates. Exh. DPS-L&A-11 at schedule SR1; exh. DPS-L&A-12 at schedule SR1.

305. CVPS's regulated affiliates are very much integrated and a part of the Vermont jurisdictional income. Tr. 11/3/04 at 135 (Gibson).

306. The retail ratemaking treatment of CVPS's investments and earnings in its regulated affiliates has no effect on the rates or return on equity of those affiliates. Behrns sur. pf. at 16; tr. 1/13/05 at 179–180 (Behrns).

Discussion

CVPS proposes to treat its FERC-regulated affiliates below-the-line³⁴⁶ for ratemaking purposes.³⁴⁷ CVPS acknowledges that this would be a departure from the way CVPS has treated

346. See footnote 264 for a definition of "the line."

347. There is no dispute regarding the proposed accounting treatment for CVPS's unregulated affiliates, such as Catamount Resources Corporation. They have been, and continue to be, accounted for below-the-line.

its regulated affiliates in its prior rate cases. The Company argues that this change in the treatment of its regulated affiliates is appropriate for two reasons.

CVPS's first argument is that, as a matter of law, the Board must treat CVPS's regulated affiliates below-the-line. For this proposition, CVPS relies upon an aspect of federal law known as the "Filed Rate Doctrine." That doctrine, as characterized by CVPS, holds that rate-regulated affiliates are subject to the exclusive ratemaking jurisdiction of FERC.³⁴⁸ CVPS now contends that treating CVPS's regulated affiliates above-the-line for Vermont ratemaking purposes denies the Company the ability to recover its FERC-approved rates (which include FERC's return on equity determinations) for the affiliates.³⁴⁹ CVPS also argues that above-the-line treatment constitutes "trapping" of costs for wholesale power, citing *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 108 S.Ct. 2428, 101 L.Ed.2d 322 (1988).

Second, CVPS claims that, as a matter of policy and discretionary judgment, the Board should approve its requested accounting treatment for its regulated affiliates. CVPS bases this argument on various changes in the electric industry in recent years.

The DPS recommends treating both the costs and the benefits of CVPS's FERC-regulated affiliates above-the-line.³⁵⁰ The DPS maintains that this has consistently been the accepted practice for CVPS and all other Vermont utilities.³⁵¹ As explained by the DPS:

Vermont's traditional rate making treatment is to include above the line in CVPS's cost of service its investments and returns on investment [sic] that were made to supply energy to Vermont ratepayers, who have defrayed the cost of those investments, and who therefore deserve to share in any attendant economic gains.³⁵²

The DPS contends that it is not advocating any positions that trigger Filed Rate Doctrine concerns. The DPS does not dispute CVPS's assertion that the Board lacks the authority or the jurisdiction to "challenge, alter or deny CVPS and its regulated affiliates the recovery of the

348. See, *Nantahala Power & Light Co. v. Thornberg*, 476 U.S. 953, 970 (1986).

349. CVPS Brief at 328 and 331.

350. The DPS expressly denies CVPS's assertion that it is recommending that only some of the Company's regulated affiliates be treated above-the-line. Tr. 1/13/05 at 178–180 (Behrns).

351. Behrns pf. at 12.

352. DPS Reply Brief at 26, citing Behrns sur. pf. at 16.

affiliates' FERC authorized ROEs."³⁵³ The DPS maintains that it is not seeking to "prevent the recovery of costs including the ROE specified in the affiliates' rate schedules . . ."³⁵⁴ as CVPS contends.³⁵⁵ Additionally, the DPS counters each of the points CVPS makes concerning the Filed Rate Doctrine. To wit, the DPS states, and the record demonstrates, that it is not asking the Board:

- to interfere with any FERC-filed rate schedules;
- to interfere with any FERC-jurisdictional service relationship;
- to deprive FERC of its plenary authority over interstate wholesale rates;
- to interfere with the ability of either CVPS or its affiliates to "enjoy" the rates ordered by FERC;
- to find that FERC's actions have been unreasonable;
- to compel CVPS to seek any changes before FERC, or to "take indirect action to change the voluntarily entered and FERC-authorized arrangement;"
- to take action to preempt FERC in matters that are within the FERC's exclusive jurisdiction.³⁵⁶

The DPS further contends that no evidence in the record supports CVPS's claim that the DPS is seeking to deny CVPS its ability to recover from ratepayers the FERC-regulated costs it incurs from its affiliates. On the contrary, the DPS states that the evidence in the record shows that CVPS can and will recover from ratepayers the full, unadjusted costs of FERC-regulated utility expenses.³⁵⁷

For the reasons explained below, we conclude that CVPS should, as in the past, account for the investments in its regulated affiliates above-the-line in rate base, and the earnings therefrom, including the income tax effect, above-the-line in its cost of service.

CVPS's principal argument is that Vermont's traditional above-the-line accounting treatment for regulated affiliates violates the Filed Rate Doctrine. This argument fails to distinguish between the tariffed rates approved by FERC for services that CVPS receives from its

353. DPS Reply Brief at 24.

354. CVPS Initial Brief at 330.

355. Behrms sur. pf. at 16.

356. DPS Reply Brief at 24.

357. DPS Reply Brief at 24.

regulated affiliates, and CVPS's equity investments and the equity in earnings related to those activities. State regulators may not interfere with the recovery of FERC-tariffed rates from ratepayers, but the state-jurisdictional ratemaking treatment of earnings by utilities from their FERC-regulated affiliates' operations is, as the DPS points out, squarely and entirely within state jurisdiction.³⁵⁸

A recent survey of the Filed Rate Doctrine's history, purpose, and scope is set out in *Pacific Gas and Electric Co. V. Lynch*, 216 F.Supp. 2d 1016 at 1029–1035, (N.D. Cal. 2002). That case involved many billions of dollars affected by California's failed experiment with deregulation. The Court, in a thorough and persuasive opinion, notes that the root and essence of the Filed Rate Doctrine can be simply stated: "that regulated providers [must] charge end-users only the rate on file with the appropriate regulatory agency."³⁵⁹ The Court observed that, "historically, the filed rate doctrine's primary purpose has been to prevent price discrimination."³⁶⁰ Over time, in regard to electricity regulation, "the filed rate doctrine came to have a subsidiary application demarking the boundary between federal and state regulatory authority." Importantly, "the doctrine also operates to prevent state regulators, as well as courts, from taking action that fails in any manner to account for the fact that in most instances today, a utility must purchase power delivered to consumers pursuant to the rate filed with the appropriate federal agency."³⁶¹ Relying on that point, the *Pacific Gas* court ruled that California regulators could not ignore the net effect of federally-regulated power transactions (in that case a net loss) on the regulated utility's necessary retail revenue requirements. Applying that ruling in the present case means that we accept the Department's position and will consider the net effect of

358. See, 30 V.S.A. § 209(3); 16 U.S.C. § 824(a), and *Re Central Maine Power Co.*, 20000WL 347057 (ME.P.U.C. 2000), at 3:

By contrast, FERC does not have authority over the allocation in a retail ratemaking proceeding of gains received by a utility from its investment in a FERC-regulated utility The allocation of revenues for purposes of retail ratemaking is an area clearly within the jurisdiction of state utility commissions.

359. *Pacific Gas*, *supra*, at 1031.

360. *Id.*

361. *Id.* at 1032.

CVPS's federally-regulated power transactions (in this case a net gain) on the regulated company's retail revenue requirements.

Nantahala does not suggest a different result. That case codified the FERC's exclusive jurisdiction over the rates charged to interstate wholesale customers. Treating CVPS's regulated affiliates above-the-line for Vermont ratemaking purposes does not, in any way, alter the rates charged to CVPS by its "wholesale-as-seller" affiliates. *Mississippi Power & Light* prohibited states from barring "regulated utilities from passing through to retail customers FERC-mandated wholesale rates."³⁶² Vermont's traditional above-the-line treatment of regulated affiliates is unrelated to the recovery of FERC-tariffed wholesale rates for utility services from Vermont retail ratepayers. In this case, we are allowing recovery from Vermont ratepayers of CVPS's costs for FERC-tariffed services from its regulated affiliates. Moreover, CVPS's contention that above-the-line treatment of the investment and earnings of its regulated affiliates constitutes "trapping" as described in *Mississippi Power & Light* is unfounded, because above-the-line treatment for retail rate setting does not affect the FERC-regulated affiliate's ability to recover its FERC-set rates. In short, CVPS's ratepayers have always paid, and will continue to pay wholesale rates the FERC finds just and reasonable, for power that is otherwise prudently obtained.

Here, too, *Pacific Gas* offers some helpful insights. Rejecting a utility argument much like that presented by CVPS, the Court stated that:

Quoting selectively from some seminal filed rate cases, PG&E argues that the filed rate doctrine forbids state regulators from looking to sources of revenue other than retail rates when determining whether existing rates are sufficient to cover operating costs.³⁶³

Expressly rejecting that concept as a matter of law, the Court held, in the same paragraph, that the filed rate doctrine, itself:

. . . does not require that retail rates be excessively high when utilities are receiving revenue from other sources. Retail rate setting based on a regulated utility's "overall financial structure" may be reasonable.

362. *Mississippi Power & Light*, *supra*, at 372.

363. *Pacific Gas*, *supra*, at 1048.

In fact, after specifically considering a situation much like CVPS's — the "offset" potential of revenues from utility sales into a regional power market, the Court explicitly stated that:

. . . if retail rates alone were insufficient to recover costs, but were sufficient in combination with other revenue, properly considered, then wholesale costs would not be trapped and there would be no violation of the filed rate doctrine.³⁶⁴

This, of course, is fully consistent with the basic *Hope*, *Bluefield*, and *Duquesne* line of cases stating that revenue determinations are tested by a functional end-result test compared to the utility's overall position.³⁶⁵

We also find that CVPS's proposed treatment is at odds with the past and current practice of CVPS and all other utilities in Vermont.³⁶⁶ The record evidence — including CVPS's rebuttal testimony — does not show any reason why we should deviate from that practice now.³⁶⁷ Simply put, changes in the industry are not of a nature, nor of a magnitude relative to CVPS, that would warrant reversal of such a fundamental, equitable, practice.

The fundamental rationale articulated by the DPS for continuing to treat regulated affiliates above-the-line is straightforward: ratepayers have paid for those investments through rates, and therefore deserve to share in the economic benefits of the investments. As CVPS's Chief Financial Officer recognized: "In my mind, those either [sic] power companies, the nuclear power companies, or VELCO . . . are very much integrated and part of the Vermont

364. *Id.* at 1048.

365. See footnote 139 and cases cited therein.

366. In fact, CVPS's position in this docket is contrary to CVPS's own testimony two years ago:

Central Vermont will continue to account for its ownership interests and other passive investments held by Custom [Investment Corporation][VYNPC was at issue in Docket 6835], dividends, interest and gains received therefrom, and tax treatment and benefits, as "above the line" for ratemaking purposes. All tax savings will result in a *lower cost of service* for Central Vermont, thus keeping rates lower than they otherwise would be without the savings from this corporate structure.

Docket 6835, Jean H. Gibson pf. 4/7/03 at 8. (emphasis added). Having asked us to rely upon that concept when it wished to have retail ratepayers compensate it for underperforming regulated affiliates in the past, CVPS is poorly placed to ask us to reverse that policy now.

367. See Deehan reb. pf. at 19.

jurisdictional income"368 We are persuaded that this rationale continues to be good public policy, and in the general interest of Vermont ratepayers.

One additional point deserves emphasis. We are particularly troubled by CVPS's attempt to treat its investment and equity earnings in VELCO as below-the-line, thus denying to retail customers the benefits of increasing profits in that sector. This effort is fundamentally inconsistent with VELCO's actual position in a very recent proceeding which involved the most significant VELCO project in half a century. In that proceeding, the Board reviewed, and ultimately approved, VELCO's request for the largest expansion of the VELCO transmission system in decades, funded by a very significant increase in its equity. In response to concerns raised by parties regarding who would benefit from the project, the Board concluded that:

The evidence before us demonstrates that the primary beneficiaries will be the citizens of Vermont, who will benefit from the improved reliability, economic development, and enhanced safety that results from a more robust electric grid.

It is true that VELCO will benefit from the project through an increase in its equity, dividends from which have traditionally been used to *reduce the bills charged to Vermont's ratepayers by VELCO's utility owners*.³⁶⁹

It is difficult to believe that CVPS, owning more than 50 percent of VELCO's stock and with direct representation on VELCO's Board of Directors, could have been unaware of the position that VELCO asked us to rely upon in that proceeding. In any case, the Order of 1/28/05, makes clear the Board's reliance on the traditional practice of treating Vermont utilities' investment in VELCO above-the-line for Vermont ratemaking purposes.³⁷⁰ Yet CVPS did not even address the VELCO proposition in its testimony, its Brief, or its Reply Brief.

Accepting the Department's position that CVPS should have included its regulated affiliates' equity in rate base, and the earnings in its cost of service, the following adjustments are required:

368. Tr. 11/3/04 at 135 (Gibson).

369. Docket 6860, Order of 1/28/05 at 223 (emphasis added).

370. In addition, we note that CVPS is the only one of VELCO's owners that has requested below-the-line treatment of its investment in VELCO.

Rate Year 1

Utility	Investment	Return on Equity	Equity Earnings
Yankee Atomic	\$ 37,891	0.00%	\$ 0
Connecticut Yankee	1,106,942	6.00%	66,417
Maine Yankee	959,702	6.50%	62,381
Vermont Yankee	2,840,577	7.50%	213,043
Subtotal	\$ 4,945,112		\$ 341,841
VELCO Preferred	\$ 702,865	11.50%	\$ 80,829
VELCO Common	6,641,355	11.50%	763,756
Subtotal	\$ 7,344,220		\$ 844,585
Total	\$12,289,332		\$1,186,426

Rate Year 2

Utility	Investment	Return on Equity	Equity Earnings
Yankee Atomic	\$ 37,891	0.00%	\$ 0
Connecticut Yankee	1,106,942	6.00%	66,417
Maine Yankee	959,702	6.50%	62,381
Vermont Yankee	2,840,577	7.50%	213,043
Subtotal	\$ 4,945,112		\$ 341,841
VELCO Preferred	\$ 702,865	11.50%	\$ 80,829
VELCO Common	15,093,950	11.50%	1,735,804
Subtotal	\$15,796,815		\$1,816,533
Total	\$20,741,927		\$2,158,474

B. Customer Service Agreement**Findings**

307. CVPS and the DPS have reached an agreement regarding the customer service issues raised in these proceedings ("Customer Service Agreement"). Exh. DPS-CVPS-Joint-1.

308. Under the terms of the Customer Service Agreement, until CVPS and the DPS establish a further, more formal resolution, and beginning as soon as CVPS can implement changes (no

later than 1/21/05), CVPS will permit former customers who have remaining unpaid balances from former accounts to add such arrearages to the balance of a newly established account, rather than requiring payment of the arrearage before a new account is established. The arrearage may be paid over a reasonable payment term. Exh. DPS-CVPS-Joint-1 at ¶ 1.

309. The Customer Service Agreement also provides that CVPS and the DPS will engage in negotiations regarding the following issues:

- the arrearage issue described in finding 308, above;
- interpretation and application of the "reasonableness" criteria for payment arrangements, including, but not limited to, how to handle situations where individual representatives appear to be responding to consumers in ways that are inconsistent with CVPS's stated understanding of the rules;
- flexibility on medical notes;
- an escalation process for the DPS to work with CVPS in cases where the Company appears to the DPS to be taking an inflexible stand on billing and policy disputes, or where CVPS does not believe it can act in the way requested by the DPS, including, but not limited to, an understanding that CVPS will seek Board clarification of the issue of applicability of Section 229 to billing disputes should cases continue to arise where CVPS believes Section 229 is a barrier to settling a dispute; and
- credit and collection practices, generally.

Exh. DPS-CVPS-Joint-1 at ¶ 2.

310. Under the terms of the Customer Service Agreement, CVPS and the DPS will report progress to the Board within 60 days of a Board order in these proceedings. Exh. DPS-CVPS-Joint-1 at ¶ 3.

Discussion

DPS and CVPS witnesses presented considerable evidence regarding several customer service issues. Subsequent to the admission of this evidence, the DPS and CVPS reached an agreement in which they state that they would like to engage in further discussions relating to these issues, and therefore ask the Board not to resolve any of the customer service issues raised in these proceedings.

The terms of the Customer Service Agreement are described in findings 308 – 310, above. We have reviewed the Customer Service Agreement and conclude that it is reasonable. The Board has long recognized the value of negotiations between willing participants, and we are pleased that the DPS and CVPS have agreed to engage in further discussions regarding these customer service issues. Therefore, we hereby approve the Customer Service Agreement in its entirety, and we make no other ruling on any of the customer service issues raised in these proceedings.

C. Rate Design

In Docket 6866, we considered a Memorandum of Understanding ("MOU") between CVPS and the Department. One of the terms of that agreement was that CVPS would file a petition for a rate redesign within 60 days of the Board's Order approving the MOU. Under the terms of that agreement, CVPS would accompany the rate design filing with a fully-allocated cost-of-service study.

As we explain above, following the Board's Order approving the MOU (with conditions),³⁷¹ CVPS sought reconsideration of the Board's Order. This ultimately led to the Department withdrawing its support for the MOU and requesting that the Board open an investigation into CVPS's rates.³⁷² As a result, the previous agreement for CVPS to submit an updated rate design no longer exists.

It has been more than eight years since the Board last comprehensively reviewed CVPS's rate design. That investigation, Docket 5835, was the result of a rate design filing that the Board required as a condition of CVPS's last fully-litigated rate case.³⁷³ CVPS has experienced changes in its cost structure over that period of time, particularly since the New England power market (and the allocation of capacity costs) is now quite different than it was in Docket 5835 and CVPS has sold its substantial ownership stake in Vermont Yankee. We find it reasonable to reexamine CVPS's present rate design in light of these and other changes. Therefore, as a

371. Docket 6866, Order of 1/27/04.

372. See Docket 6866, Order of 4/7/04.

373. Docket 5835, Order of 3/17/97 at 2.

condition of this Order, we direct CVPS to file a new rate design, supported by a fully allocated cost-of-service study, within 90 days of this Order.

IX. CONCLUSION

Vermont law in Section 218(a) of Title 30 requires that utility rates be just and reasonable. The evidence in these proceedings demonstrates that CVPS's rates over the last year (Rate Year 1) exceed just and reasonable levels by 1.25 percent. In accordance with Section 227(b), CVPS must provide a refund to its customers to return the difference between these rates and the charges that CVPS imposed under its existing tariffs for the period from April 7, 2004, through March 31, 2005. CVPS also must reduce its rates by 1.88 percent (relative to the rates under existing tariffs) commencing April 1, 2005, on a service-rendered basis.

These proceedings also address concerns that we raised in two prior decisions. As part of our approval of the Vermont Yankee sale, we required CVPS to submit a cost-of-service analysis in April of 2003 because of our expectation that the sale of Vermont Yankee would benefit CVPS and its ratepayers and could justify rate decreases. More recently, in Docket 6866, we conditionally approved a CVPS/Department agreement to freeze rates.³⁷⁴ The most significant of these conditions required CVPS to begin amortization of its large deferral accounts. In today's Order, both of these concerns are addressed. CVPS will begin amortization of its outstanding deferral accounts effective April 7, 2004. And our ruling on the overall rate levels ensures that the rates are just and reasonable, consistent with our intent in requiring the 2003 cost-of-service filing.

To the extent the findings in this Order are inconsistent with any proposed findings, such proposed findings are denied.

³⁷⁴. As we explain in the Introduction, CVPS and the Department did not agree to the conditions, so the rate freeze never took effect.

X. ORDER

IT IS HEREBY ORDERED, ADJUDGED AND DECREED by the Public Service Board of the State of Vermont that:

1. Central Vermont Public Service Corporation ("CVPS") is entitled to rates that will reduce retail revenues by approximately \$3,304,000, or 1.25 percent below existing base rates, on service rendered on or after April 7, 2004.

2. CVPS is entitled to rates that will reduce retail revenues by approximately \$4,949,000, or 1.88 percent below existing base rates, on service rendered on or after April 1, 2005.

3. CVPS shall, on or before March 31, 2005, submit a compliance filing calculating the precise decreases required by this decision. CVPS shall provide copies of the compliance filing to the parties in these proceedings.

4. As part of its compliance filing in these proceedings, CVPS shall recalculate its overearnings for 2001, 2002, and 2003, using the Vermont Department of Public Service's ("DPS") cost-of-service-based calculation methodology. When CVPS recalculates its overearnings, it shall:

- remove 100 percent of transmission revenues before applying the wholesale allocation factor;
- include the portion of Construction Work In Progress on which it does not accrue an allowance for funds used during construction;
- treat all of its regulated affiliates above the line; and
- reflect our decisions regarding Distributed Utility Planning Demand-Side Management and the 2002 Vermont Yankee Mid-Cycle Outage that are described in Paragraphs 7 and 8, below.

5. CVPS shall include in its compliance filing its proposal for refunding to ratepayers the exact amount, plus interest, that was over-collected from ratepayers during the period April 7, 2004, through March 31, 2005.

6. As described in Section VI.J.2 of this Order, CVPS shall include in its compliance filing its proposal to protect the interests of its customers in the event that the Board issues an order in Docket 6605 that would result in CVPS earning more than \$419,475 in Cable Television pole attachment revenues based on the same billing determinants used in the instant proceedings. If

CVPS elects not to submit such a proposal, CVPS shall reduce the revenues authorized by paragraphs 1 and 2 of this Order by \$447,100.

7. CVPS shall remove recurring Distributed Utility Planning Demand-Side Management expenditures from the balance in its Distributed Utility Planning Demand-Side Management deferral account, thereby reducing the balance in this account to zero. In addition, CVPS shall return to ratepayers the difference between what CVPS collected in rates for Distributed Utility Planning Demand-Side Management recurring expenses and the Company's actual expenses in 2001, 2002, and 2003 (\$184,479).

8. CVPS shall reduce the amount of its deferral account associated with Vermont Yankee's 2002 Mid-Cycle Outage by \$403,000.

9. On or before March 31, 2005, CVPS shall file tariffs in conformance with the above findings and conclusions.

10. If CVPS receives full or partial reimbursement for additional costs from Entergy Nuclear Vermont Yankee and Entergy Nuclear Operations, Inc., under the Ratepayer Protection Plan approved in Docket 6812, the Company shall book the amount received as a regulatory liability for return to ratepayers in its next rate proceeding.

11. If the decommissioning costs for Yankee Atomic, Connecticut Yankee, or Maine Yankee increase from levels now projected for 2006 and subsequent years, CVPS shall notify the Board.

12. Beginning April 1, 2006, CVPS shall book and defer the difference between the decommissioning costs for Yankee Atomic, Connecticut Yankee, and Maine Yankee for Rate Year 2 on which we set rates and the actual decommissioning cost payments. CVPS shall amortize the balance in this account in its next rate case.

13. CVPS shall follow the recording and reporting requirements of FERC Order 631 for Vermont jurisdictional ratemaking purposes. CVPS shall track and report its prior and future net salvage collections in a separate subsidiary account. CVPS shall show this separate account in future cost-of-service filings.

14. CVPS shall conduct a new depreciation study, and file it with the Board and the DPS when it is completed, which shall be no later than December 31, 2006.

15. CVPS shall spend \$6,284,444 for tree trimming expenses in Rate Year 1, and \$6,466,224 in Rate Year 2 and in each subsequent year that the rates we approve in this Order are in effect. CVPS shall spend \$304,000 for pole treatment expenses in Rate Year 1 and \$523,000 in Rate Year 2 and in each subsequent year that the rates we approve in this Order are in effect. If CVPS spends less than these amounts for tree trimming and pole treatment in a particular year, CVPS shall carry forward the unspent amounts to future years. If CVPS spends more than these amounts in a particular year, CVPS may carry forward the extra expenditures as a credit to future years.

16. In CVPS's annual report required by PSB Rule 4.903B, CVPS shall include the amounts spent on tree trimming and pole treatment, the amounts to be carried forward into the subsequent year, and a comparison of the amounts actually spent to the amounts allowed in rates.

17. The Customer Service Agreement between CVPS and the DPS that was admitted into evidence as exh. DPS-CVPS-Joint-1 is approved. Within 60 days of today's Order, CVPS and the DPS shall file a report with the Board regarding the progress of their negotiations pursuant to the Customer Service Agreement.

18. CVPS shall file a new rate design, supported by a fully allocated cost-of-service study, within 90 days of this Order.

Dated at Montpelier, Vermont, this 29th day of March, 2005.

<u>s/Michael H. Dworkin</u>	)	
	)	PUBLIC SERVICE
	)	
<u>s/David C. Coen</u>	)	BOARD
	)	
	)	OF VERMONT
<u>s/John D. Burke</u>	)	

OFFICE OF THE CLERK

FILED: March 29, 2005

ATTEST: s/Susan M. Hudson
Clerk of the Board

NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: Clerk@psb.state.vt.us)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Board within thirty days. Appeal will not stay the effect of this Order, absent further Order by this Board or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Board within ten days of the date of this decision and order.

Appendix A: Hearing Schedule

Technical Hearings held in 2004:

November 1–5, 2004

Technical Hearings held in 2005:

January 10–13, 2005

February 18, 2005

Appendix B: Procedural History

On June 13, 2002, in our Order in Docket 6545 (approving the sale of the Vermont Yankee Nuclear Power Station to Entergy Nuclear Vermont Yankee, LLC), the Board required that:

Central Vermont shall file, in April, 2003, an updated cost-of-service based upon a test year ending December 31, 2002, with appropriate additional information as necessary to determine whether a rate decrease is appropriate in 2003 or 2004.³⁷⁵

Docket 6866

Pursuant to the Board's Order in Docket 6545, CVPS filed cost of service studies on April 15, 2003. After a period of investigation by the Department, on July 11, 2003, the Department and CVPS filed a Memorandum of Understanding ("MOU") between them, which froze CVPS's rates for 2004, lowered CVPS's allowed return on equity from 11 percent to 10.5 percent for both 2003 and 2004, and established an earnings cap for 2004. The Board opened Docket 6866 to consider the MOU on July 22, 2003. After intervention by AARP, testimony, hearings, and briefs, the Board approved the MOU on January 27, 2004, but only on the condition that CVPS and the Department both affirmatively accept certain enumerated conditions. On February 3, 2004, CVPS notified the Board that it could not accept the modifications. CVPS asked for reconsideration. The Board convened a workshop based upon CVPS's motion. Subsequently, the Department requested, on March 26, 2004, that the Board open an investigation into CVPS's rates. The Board granted CVPS's motion to reconsider, in part, but the approval of the MOU never took effect as the parties to it did not accept the Board's conditions.

Docket 6946

On April 7, 2004, pursuant to 30 V.S.A. § 227(b), the Board opened the investigation requested by the Department — Docket 6946. This docket covers rates for the period from April 7, 2004, through April 6, 2005. The Board convened a prehearing conference on April 28,

375. Docket 6545, Order of 6/13/2002, at 165 (ordering paragraph 16).

2005. At that time, CVPS proposed a schedule for the rate investigation that included CVPS's express agreement to waive the statutory seven-month deadline for resolution of this proceeding. On April 30, 2005, we accepted a slightly revised proposed schedule that was agreed upon by CVPS and the DPS.

Docket 6988

On July 15, 2004, CVPS filed revised tariffs and cost-of-service schedules, requesting an increase in its retail rates of 5.01 percent, effective August 29, 2004, to be implemented on April 1, 2005.

On August 12, 2004, the Board opened Docket 6988, which suspended CVPS's tariff filing and opened an investigation into the filing.

Parallel Proceedings

By Order dated September 8, 2004, in Docket 6988, the Board agreed to consolidate Dockets 6946 and 6988 for purposes of hearings, discovery, and other scheduling matters. The test year in both dockets is calendar year 2003.

AARP was granted intervention in both Dockets.

The Board conducted a public hearing on September 14, 2004, using eight Vermont Interactive Television ("VIT") sites.

The Board held technical hearings as duly noticed and scheduled on November 1, 2, 3, 4, and 5, 2004.

After the filing of CVPS's rebuttal testimony, on December 10, 2004, the Department filed objections to the admission of certain prefiled testimony and exhibits. The Department supplemented this motion on December 27, 2004. The Department asserted that portions of CVPS's rebuttal testimony violated the provision of Section 225(a) that prohibits a company from updating a rate request or the proof that supports it. CVPS filed its response to the Department's objections on January 5, 2005. At the technical hearing on January 10, 2005, the Board granted the Department's request in large part, with the exception of two exhibits, based

upon our conclusion that the portions of the testimony to which the Department objected represented impermissible updates.³⁷⁶

The Board continued technical hearings on January 10, 11, 12, and 13, 2005.

On January 19, 2005, CVPS filed a request that the Board: (1) arrange for mediation; (2) issue an accounting order; (3) bifurcate these proceedings; and (4) hold a workshop. On January 28, 2005, the Board denied CVPS's request on all elements except the requested accounting order, for which the Board scheduled and heard oral argument on February 2, 2005.

Also on February 2, 2005, CVPS and the Department filed responses to questions from the Board regarding proposed treatment of regulated affiliates in the Company's cost of service, rate base, and overearnings calculations. In its request to the parties, the Board stated that, absent objection, it intended to incorporate the responses into the record. No party objected to the responses being included in the record; we hereby admit them.

On February 8, 2005, CVPS and the Department filed a corrected settlement concerning some, though not all, of the issues regarding power costs.

On February 10, 2005, CVPS filed a notice that there were errors in the testimony of CVPS witness Joan Gamble. On February 11, 2005, the Board directed the parties to assess the impact of the error, and scheduled a hearing on (1) the basis and implications of the error, and (2) the power cost settlement.

The Board issued an accounting order on February 18, 2005, authorizing CVPS to defer recognition of a portion of its 2004 earnings, subject to several conditions.

Also on February 18, 2005, Hearing Officer Ann Bishop held a continued technical hearing regarding the power cost settlement and the errors in Joan Gamble's testimony.

On March 16 and 17, 2005, Board staff participated in two conference calls with the parties regarding scheduling issues. As a result of those conference calls, on March 18, 2005, CVPS filed a letter clarifying that it waived the statutory seven-month deadline for resolution of Docket 6946 until March 29, 2005. On the conference calls, the parties asked if the Board would provide them with an advance electronic copy of the spreadsheet the Board used to keep track of

376. Tr. 1/10/05 at 193–196 (ruling discussed by Chairman Dworkin).

the cost-of-service and rate base decisions embodied in its final order. The parties stated that this would be a convenience for them given the short time period in which to prepare and review the required compliance filing, given the new rates' effective date of service rendered on and after April 1, 2005. On March 23, 2005, CVPS filed a letter requesting that the Board require the parties to treat the electronic spreadsheet as confidential information until today's Order was issued.

On March 25, 2005, the Board sent the parties an electronic copy of this spreadsheet, and required the parties to keep it confidential until today's Order was issued. In addition, the Board reminded the parties that in the event of a conflict between the spreadsheet and today's Order, the Order will control.

ORIGINAL

auth
jrc
[Signature]

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF PSI ENERGY, INC. FOR)
AUTHORITY TO INCREASE ITS RATES AND)
CHARGES FOR ELECTRIC SERVICE; FOR)
APPROVAL OF NEW SCHEDULES OF RATES AND)
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MANAGEMENT COST ADJUSTMENT RIDER AND)
CONTINUED USE OF A PURCHASED POWER)
TRACKING MECHANISM; AND FOR APPROVAL)
OF RELATED ACCOUNTING TREATMENT AND)
DEPRECIATION RATES AND OTHER)
ACCOUNTING RELIEF RELATIVE TO ITS)
BUSINESS)

CAUSE NO. 42359

APPROVED: MAY 18 2004

BY THE COMMISSION:

David E. Ziegner, Commissioner
Scott R. Storms, Chief Administrative Law Judge

TABLE OF CONTENTS
CAUSE NO. 42359

1.	Notice and Jurisdiction.....	3
2.	Petitioner's Characteristics.....	3
3	Current Rates and Relief Requested.....	3
4	Petitioner's Rate Base.....	3
A	Used and Useful Determinations	3
	(1) Petitioner's Generating Facilities.....	3
	(2) Petitioner's Transmission and Distribution Facilities.....	4
	(3) Petitioner's Office and General Facilities.....	5
B.	Original Cost of PSI's Electric Property.....	5
C.	Fair Value of PSI's Electric Property	6
	(1) Legal Requirements	6
	(2) Reproduction Cost New Less Depreciation.....	6
	(3) Fair Value Determination	7
5.	Fair Rate of Return.....	7
A.	Capital Structure	9
	(1) Short-Term Debt in the Regulatory Capital Structure	9
	(2) Cinergy's \$200 Million Equity Infusion to PSI.....	11
	(3) Commission Ultimate Finding Regarding PSI's Regulatory Capital Structure.....	12
B.	Cost of Capital	12
	(1) Petitioner's Cost of Common Equity Evidence	12
	(a) Dr. Morin's CAPM and Risk Premium Results	14
	(b) Dr. Morin's DCF Results.....	17
	(2) OUCC's Cost of Common Equity Evidence	19
	(3) PSI-IG's Cost of Common Equity Evidence	25
	(4) CAC Evidence on Cost of Equity	29
	(5) Testimonial Staff Testimony.....	30
	(6) Petitioner's Rebuttal Evidence on Cost of Equity	33

TABLE OF CONTENTS
CAUSE NO. 42359
(Continued)

(a)	Rebuttal Concerning OUCC's Cost of Common Equity Evidence	33
(b)	Rebuttal Concerning PSI-IG's Cost of Common Equity Evidence	38
(c)	Rebuttal Concerning Staff's Cost of Common Equity Evidence	39
(7)	Discussion and Findings Concerning Cost of Equity Capital Evidence	40
(a)	Flotation Costs (Applicable to all Models)	42
(b)	Quarterly Compounding Adjustment and Expected Dividend Yield (DCF Model)	43
(c)	Arithmetic and Geometric Means (CAPM and RP Models)	45
(d)	Other Evidence Relevant to the Determination of a Fair Return	48
(1)	Petitioner's Current Financial Condition and Financial Objectives ..	48
(2)	Relative Risk Faced by PSI	50
(3)	PSI's Operational Performance	51
C.	Ultimate Findings Regarding Fair Rate of Return for Petitioner	52
6.	Operating Income at Present Rates	54
A.	General	54
B.	Undisputed <i>Pro Forma</i> Adjustments	55
C.	Disputed <i>Pro Forma</i> Revenue Adjustments	55
(1)	Off-System Sales Profits	55
(2)	Rate Migration	56
(a)	PSI Proposal	56
(b)	Kroger Position	57
(c)	PSI Response	57
(d)	Discussion and Findings	57
D.	Disputed <i>Pro Forma</i> Expense Adjustments	58
(1)	Depreciation Expense	58
(a)	Rates	58
(i)	Evidence	58
(ii)	Discussion and Findings	69

TABLE OF CONTENTS
CAUSE NO. 42359
(Continued)

(b)	Accelerated Depreciation on NO _x Equipment	72
(i)	Evidence.....	72
(ii)	Discussion and Findings	73
(2)	Purchased Power	73
(3)	PowerShare®	73
(4)	Service Company Allocations.....	74
(a)	Evidence.....	74
(b)	Discussion & Findings	76
(5)	Sale of Accounts Receivable/Forfeited Discounts/Uncollectible Expense	77
(a)	Evidence.....	77
(b)	Discussion and Findings	80
(6)	Production O&M Expenses	80
(a)	Evidence.....	80
(b)	Discussion and Findings	82
(7)	Software Amortization Costs	83
(a)	Evidence.....	83
(b)	Discussion and Findings	83
(8)	Public Safety Advertising	83
(a)	Evidence.....	83
(b)	Discussion and Findings	84
(9)	Salaries, Wages, Benefits and Incentive Compensation	85
(a)	Evidence.....	85
(b)	Discussion and Findings	89
(10)	Voluntary Early Retirement Program Expense.....	89
(a)	Evidence.....	90
(b)	Discussion and Findings	90

TABLE OF CONTENTS
CAUSE NO. 42359
(Continued)

(11)	Property Taxes	91
	(a) Evidence.....	91
	(b) Discussion and Findings	93
(12)	Trading Expense	93
	(a) Evidence.....	93
	(b) Discussion and Findings	94
(13)	Deferred Costs	94
	(a) Deferred Dynegy Buyout Costs	94
	(i) Evidence.....	94
	(ii) Discussion and Findings	96
	(b) Merger Costs	96
	(i) Evidence.....	96
	(ii) Discussion and Findings	97
	(c) Amortization of Midwest ISO-Related Deferred Costs.....	98
	(i) Evidence.....	98
	(ii) Discussion and Findings	99
	(d) Post-In Service (Deferred) Depreciation and AFUDC	99
	(i) Evidence.....	99
	(ii) Discussion and Findings	99
(14)	Interest Synchronization	99
E	Conclusion	99
7.	Rate Level to be Authorized.....	100
8.	Revenue Allocation	101
A.	Jurisdictional Separation and Retail Cost of Service Studies	101
	(1) Evidence.....	101
	(2) Discussion and Findings	102

TABLE OF CONTENTS

CAUSE NO. 42359

(Continued)

B.	Reduction in Subsidy/Excess Revenues	103
(1)	Evidence.....	103
(2)	Discussion and Findings	103
9.	Rate Design	103
A.	Cost and Revenue Adjustment Mechanisms.....	103
(1)	Petitioner's Proposed Summer Reliability Tracker	103
(a)	Background	103
(b)	Petitioner's Proposal	104
(c)	Rationale for PSI's Proposal	105
(d)	Positions of OUCC, Intervenors, and IURC Testimonial Staff	108
(e)	PSI Rebuttal	113
(f)	Commission Discussion and Findings	115
(2)	NO _x Emission Allowance Tracker	117
(a)	PSI's Testimony	117
(b)	OUCC's, Intervenors', and IURC Testimonial Staff's Testimony	118
(c)	Commission Discussion and Findings	118
(3)	Midwest ISO-Related Cost and Revenue Adjustment Mechanism	118
(a)	PSI's Testimony	118
(b)	OUCC, Intervenors', and Testimonial Staff's Testimony	119
(c)	PSI Rebuttal Testimony	120
(d)	Commission Discussion and Findings	120
(4)	Modifications to PSI's Existing SO ₂ Emission Allowance Tracker	120
(5)	Modifications to PSI's Existing Fuel Adjustment Charge Mechanism	121
B.	Real Time Pricing ("RTP").....	121
(1)	PSI Proposal	121
(2)	PSI-IG Position	123
(3)	Kroger Position	123
(4)	Testimonial Staff Position.....	124
(5)	PSI Rebuttal	124
(6)	Evidence at Hearing	126
(7)	Discussion and Findings	126

TABLE OF CONTENTS

CAUSE NO. 42359

(Continued)

C.	PowerShare® Program Call Option Pricing Change	127
(1)	Background	127
(2)	PSI Proposal	128
(3)	Positions of Other Parties and Staff	128
(4)	PSI Response	129
(5)	Discussion and Findings	129
D.	Line Extension Advance Deposit (“LEAD”) Credit	129
(1)	Evidence	129
(2)	Discussion and Findings	131
E.	Optional High Efficiency Residential Service Rate	132
F.	Customer Connections Charges	132
G.	PSI’s Lighting Tariff Proposals	133
(1)	Evidence	133
(2)	Discussion and Findings	134
H.	General Terms and Conditions for Electric Service	134
I.	Undisputed Changes to Tariff	134
10.	Fuel Cost Adjustment Charge Issues	134
A.	New Base Cost of Fuel	134
B.	Authorized Net Operating Income for Fuel Cost Adjustment Charge Purposes	135
C.	OUCR Recommendation to Restate PSI’s Books and Records for FAC Earnings Test Purposes	135
D.	Discussion and Findings on this Issue	136
11.	Purdue University Issues	136
A.	Evidence	136
B.	Discussion and Findings	137
12.	Holding Company Issues	137

TABLE OF CONTENTS
CAUSE NO. 42359
(Continued)

A.	Evidence.....	137
B.	Discussion and Findings	140
13.	Environmental Planning	140
A.	Testimony Presented by the CAC.....	140
B.	PSI Testimony.....	141
C.	Discussion and Findings	141
14.	The FERC-Seven-Factor Test.....	142
15.	Compliance with Hold Harmless Commitment	142
	Ordering Paragraphs	143

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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CAUSE NO. 42359

APPROVED:

BY THE COMMISSION:

David E. Ziegner, Commissioner

Scott R. Storms, Chief Administrative Law Judge

On December 30, 2002, PSI Energy, Inc. ("PSI," "Petitioner," or "Company") filed its Petition for authority to increase rates and charges for retail electric utility service and approval of revised rules and regulations applicable to such service. PSI's Petition also sought approval of other items related to rates identified in the caption above, and indicated PSI's intent to comply with and utilize the provisions of the Commission's Minimum Standard Filing Requirements ("MSFRs"). Participants in this Cause included the Indiana Office of Utility Consumer Counselor ("OUCC"), and several parties that intervened in this proceeding including: the Citizens Action Coalition of Indiana, Inc. ("CAC"); Indiana and Purdue Universities; an *ad hoc* group of PSI industrial customers known as the PSI-Industrial Group ("PSI-IG"); the International Brotherhood of Electrical Workers, Local Union No. 1393 ("IBEW Local 1393"); The Kroger Co. ("Kroger"); Steel Dynamics, Inc. – Pittsboro Division ("SDI"); and Nucor Corporation ("Nucor") (collectively, the "Intervenors"). On January 21, 2003, this Commission designated from its staff Bradley K. Borum, Laura Cvengros and Matthew Inman, as testimonial staff in this Cause ("Testimonial Staff" or "Staff"). On April 1, 2003, this Commission designated Kristina Kern-Wheeler and Andrea Brandes as Counsel to the Testimonial Staff.

On February 11, 2003, this Commission conducted a Prehearing Conference and thereafter issued its Prehearing Conference Order, which established the 12 months ended September 30, 2002, as the test year in this Cause, with adjustments allowed for changes thereafter that are fixed, known and measurable and occur within 12 months following the end of the test year. May 31, 2003 was established as the cut-off date for rate base determination and for updating Petitioner's actual number of employees, salaries and wages, benefits, payroll taxes and property taxes. Petitioner was ordered to file schedules to support such updates by July 15, 2003. August 31, 2003 was established as the cut-off date for updating Petitioner's major projects as defined in this Commission's MSFRs, Petitioner's construction-work-in-progress ("CWIP") balances, any amounts deferred by Petitioner pursuant to Commission orders, the actual number of customers and the average customer usage. Petitioner identified in its Petition the following projects as major projects eligible for a special later cutoff date: its Noblesville Repowering Project, Madison Generating Station, Henry County Generating Station and Gibson Generating Station Unit 4 selective catalytic reduction equipment ("SCR"). Petitioner was required to support these August 31, 2003 updates by its rebuttal testimony filing date of October 6, 2003. PSI reserved the right to update its major project amounts up to 10 days before the final set of hearings in this Cause.

On March 28 and April 11, 2003, PSI prefled its case-in-chief testimony and exhibits in this Cause. A hearing on PSI's evidence commenced June 9, 2003. On July 15, 2003 PSI filed its May 31, 2003 Cut-Off Date Update Filing as required by the Prehearing Conference Order. On August 19, 2003, the Intervenor and the OUCC prefled testimony and exhibits constituting their respective cases-in-chief. The Intervenor's filing evidence included the CAC, PSI-IG, Purdue University, and Kroger. The Testimonial Staff filed its report, testimony and exhibits, on September 3, 2003. Petitioner prefled its August 31, 2003, Cut-Off Date Update Filing, and its rebuttal and update testimony and exhibits, on October 6, 2003. PSI filed a final update to its major projects on October 20, 2003, as provided in the Prehearing Conference Order. The OUCC filed updated and corrected Public's Exhibit ("Pub. Ex.") No. 8U and Revised Pub. Ex. No. 3 on October 31, 2003. PSI filed Petitioner's Exhibit ("Pet. Ex.") X-32 and OO-3, both as corrected, on October 31, 2003. A hearing on the prefled testimony and exhibits of the Intervenor and Testimonial Staff commenced on November 3, 2003, followed by a hearing on Petitioner's update and rebuttal evidence. On October 22, 2003, a Field Hearing in this Cause was held in Kokomo, Indiana, and on October 27, 2003, a Field Hearing was held in Bloomington, Indiana as required by Ind. Code § 8-1-2-61(b).

At the close of the record, the parties were authorized to file proposed orders and briefs in support, as well as exceptions to proposed orders and reply briefs, in accordance with an agreed upon procedural schedule. The Presiding Commissioner and Chief Administrative Law Judge attended all of the Evidentiary Hearings in this proceeding, and have thus observed the demeanor and credibility of the witnesses. All proposed findings of the parties not specifically determined in this Order are hereby rejected. This Commission, having examined the evidence and being duly advised in the premises, now finds that:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the filing of the Petition was given and published by PSI, as required by law. Proper and timely notice was given by PSI, as required by law, to its customers summarizing the manner and extent of the proposed changes in its retail rates and charges. Due, legal and timely notice of the public hearings herein was given and published by this Commission. PSI is a public utility as defined in Ind. Code § 8-1-2-1 and is subject to regulation by this Commission in the manner and to the extent provided for in the Public Service Commission Act, Ind. Code § 8-1-2. This Commission has jurisdiction over PSI and the subject matter of this Cause.

2. **Petitioner's Characteristics.** PSI is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. PSI is engaged in the business of generating and supplying electric utility service to over 740,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. PSI is a wholly-owned subsidiary of Cinergy Corp. ("Cinergy"), a publicly-held corporation, and an affiliate of The Cincinnati Gas & Electric Company ("CG&E"), also wholly owned by Cinergy.

PSI provides electric utility service to the public by means of electric utility plant, properties, equipment and facilities owned, operated, managed and controlled by it, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric utility service to retail customers in the State of Indiana. PSI also engages in sales for resale of electric energy to municipal utilities, rural electric membership corporations, Wabash Valley Power Association, Inc. ("WVPA"), Indiana Municipal Power Agency ("IMPA"), and other utilities, which in turn supply electric utility service to customers in areas not served directly by PSI.

3. **Current Rates and Relief Requested.** Petitioner's current base retail electric rates and charges were approved by Order entered by this Commission, on September 27, 1996, in Cause No. 40003 ("1996 Order" or "Cause No. 40003"). By its Petition here, PSI requests this Commission's approval to increase those rates and charges. Petitioner originally requested that this Commission approve an increase in the amount of \$200,420,000. However, after the updates made in accordance with the Prehearing Conference Order, and with certain compromise positions set forth in Petitioner's rebuttal testimony, Petitioner reduced the requested increase in its basic retail electric rates to \$178,303,000, which would represent an approximately 11.2% increase over Petitioner's current average retail rates. Pet. Ex. OO-3; Pet. Ex. DD, p. 3.

4. **Petitioner's Rate Base.**

A. **Used and Useful Determinations.** In determining Petitioner's rate base, we have been charged with making basic determinations in connection with our ultimate conclusion as to the fair value of Petitioner's utility plant actually used and useful in rendering retail electric utility service to the public. The following findings underlie these determinations.

(I) **Petitioner's Generating Facilities.** The evidence in this Cause shows that PSI owns and operates 11 generating stations, which are capable of producing approximately 6,800 megawatts ("MW") of electric generating capacity (summer-rated). Approximately 76%

of PSI's generating capacity is coal-fired, 20% is natural-gas or synthetic gas-fired, 3.5% is oil-fired and approximately 0.7% is hydro-powered. Pet. Ex. O-1. PSI's Gibson Unit 5 is jointly owned, with PSI owning 50.05% of the unit and WVPA and IMPA owning 25% and 24.95%, respectively. Pursuant to a 2002 Joint Generation Dispatch Agreement ("JGDA"), PSI jointly dispatches its generating plants with CG&E's generating plants. Pet. Ex. B, pp. 7-8.

PSI's electric generating properties consist of five primarily coal-fired stations (Cayuga, Edwardsport (one oil-fired unit), Gallagher, Gibson, and Wabash River), having a total of 20 individual generating units, one hydroelectric generating station (three units), and 27 rapid-start peaking units, including peaking units at PSI's Madison Generating Station and at PSI's Henry County Generating Station. The Madison and Henry County Stations were acquired by PSI, February 5, 2003, after this Commission approved their purchase by PSI in Cause No. 42145. PSI also owns and operates two generating units at its Noblesville Repowering Project, near Noblesville, Indiana, approved by this Commission in Cause No. 41924 and completed in June 2003. Pet. Ex. O, pp. 2-3.

PSI's coal-fired stations use primarily Illinois Basin coal from mines located in Indiana. PSI owns and operates various pollution control equipment located at its generating stations, including flue gas desulfurization equipment ("scrubbers") at its Gibson Units 4 and 5, SCRs at Gibson Units 2, 3 and 4, and modular cooling towers at PSI's Cayuga Station. Pet. Ex. B, p. 9. PSI's witness John J. Roebel, Vice President of the Generating Resources Group, described the status and costs of the Company's evolving plan to comply with federal NO_x reduction requirements ("Compliance Plan"). At the time of PSI's case-in-chief filing, the active NO_x Compliance Plan included SCRs, Boiler Optimization Programs, low-NO_x burners, and new precipitators, at various units at PSI's Gibson, Cayuga, Gallagher, and Wabash River Stations. Several additional projects have been deferred due to the receipt of early reduction credits. Mr. Roebel explained that the following NO_x Compliance Plan projects are in-service or were expected to be in-service by the summer of 2003: Boiler Optimization Programs at Cayuga Units 1 and 2, Gallagher Units 1 and 2, Wabash River Unit 2, and Gibson Unit 3; Low NO_x Burners at Gallagher Unit 4 and Wabash River Unit 6; and SCRs at Gibson Units 2, 3 and 4. Mr. Roebel testified that all of PSI's electric generating and related facilities are used and useful by PSI in the provision of utility service to its retail electric customers. Pet. Ex. O, p. 5.

No party took issue with the used and useful nature of PSI's generating facilities. We find that, as of the applicable cut-off date, updated as permitted by the Prehearing Conference Order, the above-described properties were used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

(2) Petitioner's Transmission and Distribution Facilities. The evidence presented in this Cause demonstrates that PSI owns and/or operates over 5,800 circuit miles of transmission lines, over 130 transmission substations, approximately 20,500 miles of distribution lines, approximately 440 distribution substations and various other distribution equipment, such as capacitors, line transformers, street lights and meters. PSI's transmission system is jointly owned with WVPA and IMPA. PSI is interconnected with nine other utility control areas, and

the Cinergy transmission system is interconnected with twelve other utility control areas. Pet. Ex. B, p. 10.

Approximately one year ago, PSI and CG&E transferred functional control of the operation of the Cinergy transmission system to the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"). PSI and CG&E are also parties to the East Central Area Reliability Council Agreement ("ECAR Agreement"), which coordinates the planning and operation of generation and transmission facilities and provides for maximum reliability of the regional bulk power supply. In the opinion of PSI's witness Ronald R. Jackups, Vice President, Electric System Operations, PSI's transmission facilities are used and useful in providing service to PSI's retail electric customers. Pet. Ex. M, p. 8. No party took issue with the used and useful nature of PSI's transmission and distribution ("T&D") facilities. We find that, as of the applicable cut-off date, such facilities were used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

(3) Petitioner's Office and General Facilities. The evidence shows that PSI's office facilities generally consist of the Company's corporate offices in Plainfield and numerous field offices located throughout PSI's service territory. These office facilities are used to provide customer service, sales, economic development, billing, payment, engineering, financial, accounting, service dispatch, construction, maintenance, service restoration, and other services necessary in the conduct of the electric utility business. In addition, PSI's 24-hour Call Center, garage and storeroom are located at its corporate offices. Pet. Ex. M, pp. 8-9. No party took issue with the used and useful nature of PSI's office and general facilities. We find that Petitioner's office and general facilities were, as of the applicable cut-off date, used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

B. Original Cost of PSI's Electric Property. PSI's proposed jurisdictional net original cost of its electric utility plant in service, including plant in service net of accumulated depreciation, fuel stock, emission allowances, and materials and supplies ("M&S"), was \$3,662,350,000, as of the appropriate cut-off date in this case. Pet. Ex. OO-3. No party took issue with Petitioner's jurisdictional net original cost rate base, and we find that the jurisdictional net original cost of PSI's electric utility property used and useful for the benefit of the public is \$3,662,350,000, comprised of the following elements:

Net Electric Utility Plant in Service	\$3,463,726,000
Fuel Stock	\$67,925,000
Emission Allowances	\$14,651,000
AFUDC Continuation/Deferred Depreciation	\$75,202,000
Materials and Supplies	<u>\$40,846,000</u>
Net Utility Rate Base	<u>\$3,662,350,000</u>

Pet. Ex. X-1, as updated as of October 6, 2003, and as adjusted per Pet. Ex. OO-3.

C. Fair Value of PSI's Electric Property.

(1) Legal Requirements. Ind. Code § 8-1-2-6 requires this Commission to value a public utility's property at its "fair value." In *Indianapolis Water Co. v. Public Service Comm'n*, 484 N.E.2d 635 (Ind. Ct. App., 1985), the Indiana Court of Appeals confirmed that a utility should be entitled to earn a fair rate of return on the fair value of its utility property used and useful in serving the public. The Court gave this Commission the following four basic directives regarding the application of the concept of "fair value:"

- (a) It is upon the statutory "fair value" of its used and useful property that a utility should be allowed to earn a return.
- (b) "Fair value" is not an either/or situation as to original cost or reproduction cost new. It is a conclusion or final figure, drawn from all the various values or factors to be weighed in accordance with the statute by this Commission.
- (c) In its determination of "fair value", this Commission may not ignore the commonly known and recognized fact of inflation.
- (d) While original cost is one of the factors that this Commission should consider in arriving at a "fair value" figure, it is not necessarily, in and of itself, an accurate reflection of the "fair value" of the utility's property.

In the *Indianapolis Water Co.* case, the Court of Appeals referred to the Supreme Court's holding in *Public Service Comm'n v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308, 325 (1956), that "reproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes." The Court of Appeals went on to indicate that these observations "are as pertinent today as they were in 1956." *Indianapolis Water*, 484 N.E. 2d at 640. The Court of Appeals reiterated that this Commission must authorize rates that provide the utility with the opportunity to earn a fair rate of return on the fair value of its property in *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App., 1992), *reh'g denied*.

(2) Reproduction Cost New Less Depreciation. A valuation of PSI's electric utility plant as of September 30, 2002, was made by PSI witness John J. Spanos. This study was based on the reproduction cost new of such property, less depreciation. The total appraised value at that date was determined to be not less than \$5,269,844,632. The valuation was determined by applying cost trend factors to the original cost of the various types of PSI's utility property. Reductions for depreciation were based on physical inspection, analysis of PSI's mortality experience with respect to its property history and past retirements of property and judgment based upon Mr. Spanos' experience. Pet. Ex. T, p 15. No party took issue with Mr. Spanos' valuation. After adjustments for major projects, fuel stock, emission allowances, M&S and jurisdictional separation, PSI's evidence showed, and we find, that the reproduction cost new less depreciation value of PSI's utility property is not less than \$5,799,973,000. Pet. Ex. Z-8.

(3) Fair Value Determination. The fair value of Petitioner's used and useful property at August 31, 1995, found in Petitioner's last rate case was \$2,838,569,000 (excluding M&S, fuel stockpile and *pro forma* fuel). Adjusting this value for inflation since the cut-off date in the 1996 Order produces a Consumer Price Index ("CPI") adjusted value of \$3,438,471,000. To this value must be added PSI's property additions, net of retirements, since the 1996 Order, of \$1,215,055,000, and M&S, fuel stock and emission allowances of \$203,006,000. Such a calculation results in a valuation of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public of \$4,856,532,000. Pet. Ex. C-6. We find that the fair value of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public is \$4,856,532,000.

5. Fair Rate of Return. Having determined the fair value of Petitioner's used and useful property for the provision of retail electric utility service in Indiana, we turn now to a determination of a level of net operating income that represents a reasonable return on that property. This determination requires balancing the interests of the investors and consumers through the exercise of a fair and enlightened judgment, having regard to all relevant facts. *See, Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.*, 397 N.E.2d 623, 630 (Ind. Ct. App., 1979).

In the case of *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-693 (1923), the Court set the standard against which a determination of a fair rate of return is measured:

What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

262 U.S. at 692-693.

In the case of *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the Court expanded on the guidelines to be used to assess the reasonableness of the allowed return, and recognized that revenues must cover capital costs:

From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . by that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603.

One widely accepted method for evaluating the reasonableness of a public utility's return involves a consideration of capital structure and development of an overall weighted cost of capital. However, this Commission utilizes cost of capital estimation evidence as only one factor in determining the fair rate of return for a public utility. Cost of capital testimony, while relevant evidence in the determination of a fair rate of return, is clearly not the only consideration. We have repeatedly found:

Cost of capital is an important element of the ratemaking process. However, we have pointed out many times that cost of capital is not synonymous with the fair rate of return. Ultimately, the determination of a fair rate of return is the prerogative of the Commission, taking into consideration all the relevant evidence. The objective is to determine the return which is reasonably sufficient to assure confidence in and financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. *Columbus Gas Light Co. v. Public Serv. Comm'n of Ind.*, 193 Ind. 399, 404-406, 140 N.E. 538, 540 (1923); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-693 (1923). These goals go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist. . . . Rather, we are to exercise the flexibility afforded us by statute and the Indiana Supreme Court.

See, PSI Energy, Inc. Cause No. 40003, (Ind. Util. Reg. Comm'n, September 27, 1996), at 34-35.

The Indiana courts have supported this view and have held that, in determining an appropriate rate of return, it is not necessary for this Commission to determine the cost of capital, and that the Commission may consider evidence regarding the cost of capital in conjunction with other evidence presented in the proceeding. *Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.*, 397 N.E.2d 623, 630 (Ind. Ct. App., 1979); *Office of Utility Consumer Counselor v. Public Serv. Co.*, 449 N.E.2d 604, 607 (Ind. Ct. App., 1983). Determining a fair rate of return is the prerogative of this Commission after giving weight to all material evidence. The Indiana Court of Appeals has recognized that it is appropriate for this Commission to utilize the rate of return as a "balance wheel" to provide a limited margin of error for the resolution of other issues. The Commission's primary objective is to reach an overall result that is equitable and that will permit continuity of utility services on a sound financial basis. *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 351 N.E.2d 814, 821 (Ind. Ct. App., 1976). The determination of a utility's revenue requirement is primarily an exercise of informed regulatory judgment. If the judgment is to be exercised properly, the Commission must examine every aspect of the utility's operation, and the economic environment in which the utility functions, to ensure that the data it has received is representative of operating conditions that will, or should, prevail in future years. *City of Evansville v. Southern Ind. Gas & Electric Co.*, 339 N.E.2d 562, 568 (Ind. Ct. App., 1975).

With this background in mind, we now turn our attention to the evidence submitted in this proceeding concerning Petitioner's capital structure, cost of capital, and other matters relevant to the determination of a fair return for Petitioner, including: the relative risks facing the energy industry and PSI; PSI's financial condition, financing requirements and financial objectives; PSI's credit quality; and PSI's performance in rendering retail electric utility service in Indiana.

A. Capital Structure. The Prehearing Conference Order provided that the economic and financial data used in determining Petitioner's cost of capital and capital structure shall not be restricted as to the time or method of adjustment used for financial and accounting exhibits, but should be as current as possible and updated as of the prefiling dates set forth in that order. Pursuant to this provision, Petitioner's October 6, 2003 filing updated its actual capital structure as of August 31, 2003, with certain updates for events that occurred in September 2003. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Intervenor Kroger took issue with PSI's regulatory capital structure and argued that short-term debt should be included in PSI's capital structure for ratemaking purposes. Kroger Ex. No. 1, p. 16. Additionally, PSI-IG witness Michael Gorman expressed concern about the \$200 million equity infusion to PSI from its parent company, Cinergy Corp. PSI-IG Ex. No. 3, p. 8. PSI witnesses Stephen M. Farmer and Ronald R. Reising addressed these arguments and concerns relative to the capital structure to be utilized in this case for ratemaking purposes.

(1) Short-Term Debt in the Regulatory Capital Structure. Mr. Stephen Farmer, PSI's Revenue Requirements Manager, opposed the inclusion of short-term debt in PSI's capital structure for regulatory purposes, explaining that short-term debt is used to finance items that are not in rate base, such as certain regulatory assets and cash working capital needs and CWIP. Pet. Ex. QQ, p. 2. Mr. Farmer pointed out that this Commission, in excluding short-

term debt from PSI's regulatory capital structure in Cause No. 40003, rejected the OUCC's argument in that case -- and not repeated by the OUCC here -- that the portion of PSI's short-term debt that exceeded PSI's CWIP balance should be included in PSI's capital structure for ratemaking purposes. *Id.*

Mr. Farmer further noted that in Cause No. 40003, the OUCC witness Matthew Kahal testified that it would be appropriate to exclude short-term debt from the capital structure only if short-term debt balances are comparable to (or less than) CWIP balances. Mr. Farmer pointed out that the balance of PSI's short-term debt outstanding at August 31, 2003, was \$112,333,000, while its CWIP balance was \$154,456,000. While acknowledging that a portion of PSI's CWIP is eligible for CWIP ratemaking treatment (*i.e.*, qualified pollution control expenditures), Mr. Farmer pointed out that short-term debt is also used to finance working capital needs and costs of assets that are not recovered in rates. Pet. Ex. QQ, p. 3. As for a suggestion that short-term debt may have become a permanent component of PSI's capital structure, Mr. Farmer observed that PSI's investment in plant in service has increased significantly since the end of the test period in this case -- yet during this same period PSI's short-term debt balance has not increased appreciably.

In support of Kroger's position, Mr. Kevin Higgins quoted from Standard and Poor's 2001 publication, "Corporate Ratings Criteria" that states:

Traditional measures focusing on long-term debt have lost much of their significance, since companies rely increasingly on short-term borrowings. It is now commonplace to find permanent layers of short-term debt, which finance not only seasonal working capital but also an ongoing portion of the asset base.

Mr. Farmer responded that financial analysts do not make a regulatory distinction between used and useful plant included in rate base and other assets. Pet. Ex. QQ, p. 5. Financial analysts, he said, include short-term debt as part of company capitalization because the "asset base" of a company would include investments in plant not receiving rate treatment (*e.g.*, non-qualified pollution control property CWIP investments and regulatory assets). During cross-examination, Mr. Farmer also pointed out that the same Standard and Poor's publication quoted by Mr. Higgins also states that "Flexibility can be jeopardized when a firm is overly reliant on bank borrowings or commercial paper." Tr. at Y88.

As additional support for its position that short-term debt should be included in PSI's capital structure, Kroger emphasized the difference between PSI's capitalization and PSI's original cost depreciated rate base, arguing that a utility's rate base should approximate its capitalization. Kroger Ex. No. 1, pp. 10-11.

In response, Mr. Farmer indicated that that balance between capitalization and rate base is simply a theory that presumes "perfect ratemaking" -- that is, perfect and perfectly timed recovery of the utility's costs, and consistently fair returns earned by the utility, year in and year out. In reality, ratemaking and recovery of costs are not perfect. The utility may or may not

earn consistently fair returns year in and year out. Tr. at Y56-61 and Y89-90. Mr. Farmer presented a number of explanations for the difference between PSI's rate base and its capitalization. These explanations include: changes in accounts receivables balances; changes in accounts payable balances; different rate case cut-off dates for rate base on the one hand, and capital structure on the other; PSI's use of its sale of accounts receivables proceeds to redeem outstanding first mortgage bonds and preferred stock; impacts on capital structure and retained earnings produced by various accounting requirements; and less than reasonable returns earned by PSI at various times, effectively shrinking investors' capital investments. Tr. at Y56-61. With regard to this latter reason -- investors' capital investments effectively diminishing over time to the extent that the utility earns less than a reasonable return -- Mr. Farmer emphasized that utility investors expect and demand a reasonable return over time of their principal actually invested, not a return on a diminished capital investment. Tr. at Y60.

The evidence indicates that Petitioner's short-term debt balances have been used to finance construction-work-in-progress and other capital items, such as regulatory assets, not in PSI's rate base. If short-term debt had been financing plant additions in Petitioner's rate base, the short-term debt would have been increasing appreciably as substantial plant was added. Moreover, as Mr. Farmer pointed out, the cost of short-term debt is reflected in the application of Allowance for Funds Used During Construction ("AFUDC") to CWIP expenditures. Consequently, customers regularly receive the benefit of Petitioner's lower-cost short-term debt through lower capitalized AFUDC rates. Accordingly, based on our review of the evidence presented in this Cause, we conclude--as we did in Cause No. 40003--that PSI's short-term debt should not be included in its capital structure for ratemaking purposes.

(2) Cinergy's \$200 Million Equity Infusion to PSI. PSI-IG witness Michael Gorman expressed concern over PSI's receipt of a \$200 million equity infusion from its parent company, Cinergy Corp., and recommended that certain assurances be made by PSI in order to support its claim that the equity infusion will positively enhance its credit rating. PSI-IG Ex. No. 3, p. 8. The assurance Mr. Gorman wanted was that such equity infusion will occur without increasing Cinergy's overall debt level. *Id.* Mr. Gorman argued that if Cinergy is making an equity infusion in PSI by issuing additional debt, the higher debt level of Cinergy could have as much negative credit rating impact on PSI as the positive impact credited from the increase in PSI's common equity and the decrease in its debt leverage. *Id.* Mr. Gorman noted that PSI's bond rating is heavily tied to Cinergy's bond rating and he said that analysts were concerned with Cinergy's highly leveraged capital structure. *Id.* at 9.

In response to Mr. Gorman's concern, PSI witness Ronald R. Reising, Cinergy's Vice President of Finance, noted that Cinergy has raised over \$900 million in additional equity since December 2001, and that the funds raised by Cinergy's equity issuances supported the funding of the \$200 million infusion to PSI. Pet. Ex. EE, p. 15. Similarly, in earlier testimony, PSI witness Mr. James E. Rogers, Chairman and CEO of both Cinergy and PSI, explained that Cinergy made the \$200 million equity infusion in order to strengthen PSI's balance sheet and maintain PSI's credit ratings. Pet. Ex. A, p. 29.

Regarding the \$200 million equity infusion from PSI's parent, we conclude that PSI adequately explained both the source of the funds (from the \$900 million in equity issuance funds raised by Cinergy since December 2001) and, more importantly, the use of the funds to strengthen PSI's balance sheet and preserve PSI's credit quality.

(3) Commission's Ultimate Finding Regarding PSI's Regulatory Capital Structure. Based on the foregoing, we find that the PSI capital structure to be used in this case is:

<u>Description</u>	<u>Capitalization</u>
Common Equity	\$1,603,374,000
Preferred Stock	42,333,000
Long Term Debt	1,402,254,000
Deferred Income Taxes	519,273,000
Unamortized ITC – 1970 & Earlier	193,000
Unamortized ITC – 1971 & Later	30,571,000
<u>Customer Deposits</u>	<u>9,741,000</u>
<u>Total Capitalization</u>	<u>\$3,607,739,000</u>

B. Cost of Capital. It was undisputed that PSI's evidence demonstrated that its embedded cost of long-term debt was 6.37%, preferred stock 6.11%, and customer deposits 6%, or that post-1970 unamortized investment tax credits should have the weighted cost of long-term debt, preferred stock and common equity capital. Pet. Ex. X-32 Corrected; Pet. Ex. VV-1. There was disagreement only concerning Petitioner's current cost of common equity capital. Petitioner, OUCC, and PSI-IG submitted testimony sponsoring the results of their respective cost of common equity capital studies. Staff submitted testimony concerning the results of these three studies. CAC submitted testimony addressing certain aspects of Petitioner's risk profile.

(1) Petitioner's Cost of Common Equity Evidence. In his testimony filed on March 28, 2003, Petitioner's witness Dr. Roger A. Morin recommended that PSI be allowed to earn an 11.5% return on its common equity capital, based on studies he performed using the Capital Asset Pricing Model ("CAPM"), the Risk Premium ("RP"), and Discounted Cash Flow ("DCF") methods of determining the cost of such capital. Pet. Ex. G, p. 4. During his oral testimony on June 12, 2003, Dr. Morin indicated that there had been a slight decrease in long-term interest rates and some slight changes in dividend yields from the time of his March 2003 prefiled testimony, resulting in a slight decrease in his recommended return on common equity from 11.5% to in the vicinity of 11.2% to 11.3%. Dr. Morin noted in his oral update that he would be submitting a full-fledged update before the final phase of hearings. Tr. at G109-G110. In his testimony filed as a part of PSI's August 31, 2003 Update, Dr. Morin reduced his recommended cost of common equity to 11.2%, based on more recent data. Pet. Ex. TT, pp. 2-3. Use of Dr. Morin's cost of common equity in PSI's proposed regulatory capital structure produced an overall, weighted cost of capital of 7.63%. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Dr. Morin performed two CAPM analyses, one using what he characterized as the "plain vanilla" CAPM and another using an empirical approximation of the CAPM ("ECAPM"). He also performed six RP analyses: (i) a historical RP analysis of the electric utility industry using Treasury bond yields; (ii) a historical RP analysis of the electric industry using A-rated utility bond yields; (iii) a historical RP analysis of the natural gas utility industry using Treasury bond yields; (iv) a historical RP analysis of the natural gas industry using A-rated utility bond yields; (v) a study of the risk premiums allowed in the electric utility industry relative to Treasury bond yields; and (vi) a study of the risk premiums allowed in the electric utility industry relative to A-rated utility bond yields. He performed DCF analyses, using both Zacks Investment Research, Inc. ("Zacks") and Value Line Investors' Service ("Value Line") dividend growth estimates, on three surrogates for the Company: (i) a group of electric utilities that make up Moody's Electric Utility Index; (ii) a group of investment-grade, vertically integrated electric utilities; and (iii) a group of natural gas distribution utilities. Pet. Ex. G, pp. 4 and 46; and Pet. Ex. TT, p. 3. His revised cost of common equity capital results ranged from 10.3% to 12.5%, averaging 11.2%. Pet. Ex. TT, p. 3.

In his testimony, Dr. Morin indicated that he believes that all of the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the current electric utility industry. Dr. Morin indicated that he believes that past earnings and dividends of electric utilities are simply not indicative of the future, as historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation to a more competitive environment. As a result, Dr. Morin testified that he believes that these historical data are not representative of the future long-term earning power of these companies. Moreover, Dr. Morin indicated that he believes that historical growth rates are not representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. Pet. Ex. G, pp. 13-14. Dr. Morin indicated that a similar conclusion applies to historical risk premiums. He testified that historical measures of risk, such as beta, are necessarily downward-biased in assessing the present fluid circumstances of the electric utility industry. Current changes in the fundamentals of electric utilities are not yet fully reflected in historical data. Pet. Ex. G, p. 14.

Dr. Morin stated that the return allowed for a public utility must necessarily reflect the investors' return requirements and be commensurate with returns on investments in other firms having corresponding risks. The allowed return, he said, should be sufficient to assure confidence in the financial integrity or strength of the firm, in order to maintain its creditworthiness and the ability to attract capital on reasonable terms. The attraction of capital standard focuses, he testified, on investors' return requirements that are generally determined using market value methods, such as the RP, CAPM or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk. Pet. Ex. G, pp. 6-8.

Dr. Morin testified that the heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return, and concluded that the end result of this Commission's decision in this proceeding should be to allow PSI the opportunity to earn a return on common equity capital that is: (i) commensurate with returns on investments in other firms having corresponding risks; (ii) sufficient to assure confidence in PSI's financial integrity; and (iii) sufficient to maintain PSI's creditworthiness and ability to attract capital on reasonable terms. Pet. Ex. G, p. 10.

(a) Dr. Morin's CAPM and Risk Premium Results. Dr. Morin testified that the fundamental concept underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. Denoting the risk-free rate by " R_F " and the return on the market as a whole by " R_M ", he stated the formula for the "plain vanilla" CAPM is as follows:

$$K = R_F + \beta(R_M - R_F)$$

Dr. Morin testified that under this formula the return required by investors (K) is made up of a risk-free component (R_F), plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three inputs are required: the risk-free rate (R_F), the beta (β) and the market risk premium ($R_M - R_F$). For the risk-free rate, Dr. Morin used 5.0%. For the beta, he used 0.72, and for the market risk premium, he used 6.8%. Pet. Ex. G, p. 15.

Dr. Morin explained that the basis for his 5% risk-free rate was the actual yield on long-term Treasury bonds, in February 2003, shortly before he filed his initial testimony in March of 2003. Pet. Ex. G, p. 16. Dr. Morin's market risk premium of 6.8%, was based on the results of both forward-looking and historical studies of long-term risk premiums, as shown in the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2002 Yearbook*. Pet. Ex. G, p. 20. This study, he said, compiles security returns from 1926 to 2001 and shows that a broad market sample of common stocks outperformed the income component of long-term U.S. government bonds by approximately 7.5%. Pet. Ex. G, p. 20.

To determine an appropriate beta for PSI, whose common stock is not publicly traded, Dr. Morin used two proxies -- the average beta for the electric utility industry, as reported by Value Line, and the average beta of a group of natural gas distribution utilities that he selected. Pet. Ex. G, p. 17. The average beta for the electric utility industry, he said, was 0.71 as of January 2003, and the average beta for the group of natural gas distribution utilities was 0.72 as of January 2003. Pet. Ex. G, pp. 17-18; Pet. Ex. G-2; and Pet. Ex. G-3. He observed that ongoing changes in risk fundamentals are not yet fully reflected in historical beta estimates for electric utilities and, as a result, the historic beta estimates are downward biased. Pet. Ex. G, p. 19. Given the dramatic changes occurring in the electric utility operating environment, Dr. Morin stressed the need to be forward-looking because investors consider prospective long-term risks when making investment decisions. Pet. Ex. G, p. 18. In his "plain vanilla" CAPM study,

Dr. Morin used a beta of 0.72, for what he characterized as a conservative estimate, of the beta applicable to PSI's electric utility operations. Pet. Ex. G, p. 20. Use of that beta, together with a risk-free rate of 5.0% and a market risk premium of 6.8%, produced in Dr. Morin's initial testimony a CAPM-based estimate of PSI's cost of common equity of 9.9% ($5.0\% + 0.72 \times 6.8\%$), and 10.2% with flotation costs. Pet. Ex. G, p. 23.

Dr. Morin testified that because the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00, expanded CAPMs have been developed, which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias and thereby enrich its conceptual validity. Pet. Ex. G, p. 23. Using this "empirical" version of the CAPM, he said that the formula becomes:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \beta (R_M - R_F)$$

Utilization of this formula produced a return on common equity of 10.4% without flotation cost, and 10.7% with flotation costs, using 5.0% for R_F , a market risk premium of 6.8% and a beta of 0.72. Pet. Ex. G, p. 23.

For his RP approach to cost of common equity, Dr. Morin examined historical risk premiums for the electric utility industry from 1931 to 2001 using Moody's Electric Utility Index as an industry proxy. Pet. Ex. G, p. 24; and Pet Ex. G-4. A risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The resulting average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds were yielding 5.0% shortly before Dr. Morin's March 2003 filing, he determined the implied cost of equity for the average electric utility using this method to be $5.0\% + 5.6\% = 10.6\%$ without flotation cost, and 10.9% with flotation costs. Pet. Ex. G, p. 24.

Dr. Morin testified that he did not adjust his risk premium results to account for PSI's risk relative to the industry because PSI's total investment risks are currently comparable to those of the electric utility industry. He noted that PSI's bonds are currently rated "A3", which is close to the industry average. Because the historical risk premium estimate from the Moody's electric utility industry group reflects the risk of the average electric utility and because PSI's total investment risks are currently comparable to those of the industry, Dr. Morin concluded that the expected equity return from the Moody's group is applicable to PSI. Pet. Ex. G, p. 24.

Using the same historical analysis described above, but substituting the yield on A-rated electric utility bonds for the yield on U.S. Treasury bonds, produced an average risk premium of 4.5% in Dr. Morin's initial testimony. Pet. Ex. G, pp. 25-26; and Pet. Ex. G-5. Adding this premium to the current yield on A-rated bonds of 7.0% produced an implied cost of equity for the average electric utility of 11.5% without flotation cost, and 11.8% with flotation costs, he said. Pet. Ex. G, p. 26.

Applying the same risk premium analysis to the natural gas utility industry produced an implied cost of equity for the average electric utility of 10.7% without flotation cost, and 11.0% with flotation costs, using long-term Treasury bonds for the risk free rate, in Dr. Morin's initial testimony. Pet. Ex. G, p. 26; and Pet Ex. G-6. Substituting the long-term bond yield for A-rated utilities for the yield on Treasury bonds produced an average risk premium of 5.0%, which, when added to the yield on A-rated bonds of 7.0% at the time of his initial testimony, produced an implied cost of equity of 12% (7.0% + 5.0%) without flotation cost, and 12.3% with flotation costs.¹ Pet. Ex. G, pp. 26-27; and Pet Ex. G-7.

Dr. Morin also examined the historical risk premiums implied in the returns on common equity ("ROE") allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. Pet. Ex. G, p. 27. This allowed risk premium approach produced an average ROE spread over long-term Treasury yields of 5.1% for the 1993-2002 period. Dr. Morin's data showed that there has been a rising trend of the risk premium in response to lower interest rates and rising competition and restructuring. Pet. Ex. G, pp. 27-28. These studies produced costs of common equity of 11.3% and 11.4% at the time of Dr. Morin's initial testimony, depending on whether long term Treasury bonds or A-rated utility bonds were used. Pet. Ex. G, pp. 27-30. Dr. Morin updated the CAPM and RP results of his study in October 2003, using data as of the end of August. He indicated that, as of the end of August 2003, the yield on long-term Treasury bonds was 5.3%, compared to 5.0% in February when he prepared his initial study. The following table summarizes Dr. Morin's ROE estimates obtained from his CAPM and RP studies, updated as of August 31, 2003:

Risk Premium Methods	%ROE
CAPM	10.9%
ECAPM	11.4%
Risk Premium Electric Utility Treasury Bonds	11.2%
Risk Premium Electric Utility "A"-Rated Bonds	12.1%
Risk Premium Natural Gas Treasury Bonds	11.3%
Risk Premium Natural Gas "A"-Rated Bonds	12.5%
Allowed Risk Premium Treasury Bonds	11.3%
Allowed Risk Premium "A"-Rated Bonds	11.4%

Pet. Ex. TT, p. 3.

¹ Dr. Morin stated that all of his market-based estimates (CAPM, RP and DCF) include an adjustment for flotation costs, as these costs are incurred but not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. Pet. Ex. G, p. 42. Flotation costs include a direct component in the form of compensation to the security underwriter for its marketing/consulting services, for risks involved in distributing the issue, and for operating expenses associated with the issue. Flotation costs also include an indirect component in the form of downward pressure on the stock price as a result of the increased supply of stock from the new issue, the latter frequently referred to as market pressure. Pet. Ex. G, p. 42, and Pet. Ex. G, Appendix A.

(b) Dr. Morin's DCF Results. Dr. Morin observed that according to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. Pet. Ex. G, p. 30. One widely used method to measure these anticipated benefits in the case of a non-static company, he said, is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process, he said, can be represented by the following formula, for the traditional DCF model:

$$K_e = D_1/P_0 + g$$

K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_0 = current stock price

g = expected growth rate of future dividends, earnings, book value

Pet. Ex. G, pp. 30-31. The idea of this market value approach, is to infer K_e from the observed share price, dividend, and from an estimate of investors' expected future growth. Pet. Ex. G, p. 31.

Dr. Morin applied the DCF model to three proxy groups for PSI: (i) Moody's electric utilities; (ii) a group of vertically integrated electric utilities that he selected; and (iii) a group consisting of widely-traded dividend-paying natural gas distribution companies, drawn from the Value Line edition of the Value Line Gas Distribution Group. Dr. Morin used the spot dividend yields reported in the January 2003 edition of Value Line. Pet. Ex. G, pp. 31-32. Because dividends are paid quarterly in practice, Dr. Morin observed, the investors' required return must be determined with a DCF model that reflects the quarterly nature of dividends payments. Pet. Ex. G, p. 33; see also, Pet. Ex. G, pp. 33-36; and Pet. Ex. G-8.

Dr. Morin explained that, as a proxy for expected growth, he examined growth estimates developed by professional analysts employed by large investment brokerage institutions. These forecasts, he said, are made by large reputable organizations, and the data are readily available to investors and representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Dr. Morin used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. He also used Value Line's growth forecast as an additional proxy. Pet. Ex. G, p. 37.

Dr. Morin did not use historical growth rates in his DCF approach because he believes that they have little relevance as proxies for future long-term growth. Pet. Ex. G, p. 38. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Pet. Ex. G, p. 38. He illustrated this point by adding the historical growth rates over the past five years of 2.1%, -1.3%, and 3.5% for the electric utility companies that make up Value Line's Electric Utility composite group to the average 5.0% dividend yield

prevailing in February of 2003 for the companies he examined; this produced cost of equity estimates of 7.1%, 3.7%, and 8.5%, using earnings, dividends, and book value growth rates, respectively. He observed that such estimates of common equity costs are less than, or close to, the cost of debt for these companies. Pet. Ex. G, p. 38.

Dr. Morin, in his initial testimony, stated that for the electric utilities that make up Moody's Electric Utility Index (Column 2 of page 1 of Pet. Ex. G-10), the average long-term growth forecast obtained from Zacks was 5.2% and, adding this growth rate to the average expected dividend yield of 5.8% (Column 3), produced an estimate of equity costs of 11.0% for the group, unadjusted for flotation costs or quarterly timing. Providing for the quarterly timing of dividends and adding an allowance for flotation costs to these results brings the cost of equity estimate to 11.5%, shown in Column 5 of Pet. Ex. G-10. Pet. Ex. G, p. 39. Using Value Line's long-term earnings growth forecast of 5.4%, instead of the Zacks consensus forecast, the cost of equity for the Moody's group is 11.1%, and, after provision for quarterly timing and allowance for flotation costs, the cost of equity estimate is 11.6%, as shown on page 2 of Pet. Ex. G-10. Pet. Ex. G, p. 39.

Using a group of 13 vertically integrated electric utilities (*i.e.*, publicly listed parent companies whose electric utility operating subsidiaries include both transmission and distribution ("T&D") and generation activities), and the average long-term growth forecast obtained from Zacks of 6.6% for this group, and adding this growth rate to the average expected dividend yield of 5.6%, produced an estimate of equity costs of 12.2% for the group. Pet. Ex. G, pp. 39-40; and Pet. Ex. G-11. Providing for quarterly timing of dividends and adding an allowance for flotation costs to the results of Column 4 of Pet. Ex. G-11 brings the cost of equity estimate to 12.7%. Pet. Ex. G, p. 40. Removing the impact of significant outliers from the result, to produce a truncated average, resulted in a 12.0% cost of common equity. Pet. Ex. G, p. 40.

Using Value Line's long-term earnings growth forecast of 6.5%, instead of the Zacks consensus forecast, Dr. Morin produced a cost of equity for the vertically integrated electrics of 12.0%. Pet. Ex. G, p. 40. Allowance for quarterly timing and flotation costs brought that cost of equity to 12.5%. The truncated average was 12.0%. Pet. Ex. G, p. 40.

Dr. Morin testified that using the average long-term growth forecast obtained from the Zacks corporate earnings database for the gas distribution group of 5.5%, and adding that growth rate to the average expected dividend yield of 4.7%, produced an estimate of equity costs of 10.2% for the gas distribution group. Pet. Ex. G, p. 41, and Pet. Ex. G-12. Dr. Morin added that providing for quarterly timing of dividends and flotation costs to this result brings the cost of equity estimate to 10.7%. Pet. Ex. G, p. 41. Repeating the same procedure, but using Value Line's long-term earnings growth forecast of 8.7%, instead of the Zacks consensus growth forecast, produced a cost of common equity for the gas distribution group of 13.6%, unadjusted for flotation costs. Pet. Ex. G, p. 41. Adding an allowance for flotation costs and allowing for quarterly dividend payments brought this cost of equity estimate to 13.8%, while the truncated average result was 13.6%. Pet. Ex. G, p. 41; and Pet. Ex. G-12.

Dr. Morin updated the DCF results of his study in October 2003, using data as of the end of August. He indicated that the DCF results for the vertically integrated electric and natural gas distribution utilities had decreased significantly from February when he prepared his initial study, in part due to the substantial revision in dividend taxation which lowered dividend yields (increased stock prices) and in part due to the lowering of utility growth forecast by analysts. The table below summarizes Dr. Morin's DCF estimates of the costs of common equity to PSI, updated as of August 31, 2003:

DCF Study	%ROE
Moody's Electrics Zacks Growth	10.3%
Moody's Electrics Value Line Growth	10.3%
Vertically Integrated Electrics Zacks Growth	10.6%
Vertically Integrated Electrics Value Line Growth	10.8%
Natural Gas Distribution Zacks Growth	10.4%
Natural Gas Distribution Value Line Growth	12.1%

Pet. Ex. TT, p. 3.

(2) OUCC's Cost of Common Equity Evidence. Edward R. Kaufman, OUCC's Lead Financial Analyst testified regarding PSI's financial condition, overall capital market conditions, and conducted analyses resulting in an initial recommended cost of equity of 9.15%. Mr. Kaufman subsequently updated his recommended cost of equity in October 2003 ("October Update") to 9.25%. Pub. Ex. No. 8U, p. 2. To estimate PSI's cost of equity, Mr. Kaufman employed DCF analyses as well as CAPM methodologies, using two proxy groups of electric companies as well as PSI's parent company, Cinergy. Pub. Ex. No. 8, p. 4. Mr. Kaufman's cost of equity estimates from these analyses ranged from 7.94% to 10.12% in his initial prefiled testimony, and 8.02% to 9.67% in his October Update. Pub. Ex. No. 8, p. 4; and Pub. Ex. No. 8U, Schedule 1, p. 2.

Mr. Steven C. Carver, a principal in the firm Utilitech, Inc., also testified on behalf of the OUCC, and sponsored a weighted overall cost of capital of 6.86%, based upon Mr. Kaufman's initial 9.15% recommendation. Both were later updated to 6.74% and 9.25%, respectively. Pub. Ex. No. 8, p. 4. and Pub. Ex. 3 Revised at Schedule D. OUCC witnesses Mr. Timothy Geswein and Dr. Peter M. Boerger also testified regarding PSI risk levels and required ROE in light of such risks.

Mr. Kaufman characterized Petitioner's financial condition as strong, with a common equity ratio of 47.9% (using a "traditional" securities rating capital structure) that is higher than the 24 electric utilities covered in the C.A. Turner Utility Reports ("Turner Reports"). Pub. Ex. No. 8, p. 5. His testimony quoted from Cinergy's presentations to analysts and the testimony of its CEO, Mr. Rogers, to illustrate how the Company believes it has solid liquidity, recently affirmed investment grade credit ratings, increasing cash flow based on reduced environmental

capital requirements and rate increases, and substantially reduced risk due to regulatory and legislative relief as well as improvements in system reliability. Pub. Ex. No. 8, p.6.

Mr. Kaufman observed that the interest rates for US Treasury Bonds are currently at their lowest point in 30-40 years, and indicated that the year-end 2002 yield on long-term government bonds was 4.55% -- the lowest year-end yield since 1966. He also identified the fact that the yield on "A" rated utility bonds as of August 5, 2003 was 6.64% and that their annual average yield had not been below 7% since 1968. Pub. Ex. No. 8, p. 7. Mr. Kaufman added that the current 4% prime rate is the lowest since April of 1959. These low costs of debt, he explained, should translate into lower costs of equity as well. Pub. Ex. No. 8, p. 7. Mr. Kaufman noted that the Petitioner recognized a 130 basis point decline in the long term risk free rate of return since Petitioner's last rate case (as demonstrated comparing of Dr. Morin's CAPM risk free rate of return in the last case (6.3%) and the CAPM risk free rate of return he used in the current proceeding (5.0%)).

Mr. Kaufman stated that because PSI's common stock was not publicly traded, one could not apply the DCF or CAPM model directly to PSI. Rather, PSI's cost of equity could be estimated only through the use of a proxy group. Pub. Ex. No. 8, p. 8. He first applied the DCF and CAPM analysis to Dr. Morin's selection of vertically integrated electric utilities as a proxy group. Pub. Ex. No. 8, p. 11. He also examined his own proxy group of electric utilities, using a set of screening criteria that yielded a similar but not identical selection to that used by Dr. Morin. Mr. Kaufman also used Cinergy as a proxy for PSI. Pub. Ex. No. 8, p. 11. The main difference between the criteria Mr. Kaufman used to form his proxy group and that which Dr. Morin used was that Mr. Kaufman included a combination of electric and gas companies in his proxy group and required companies he used in his proxy group to derive at least 75% of revenues from electric operations (instead of 50%, as used by Dr. Morin). Pub. Ex. No. 8, p. 11. Mr. Kaufman explained that he believes that all three of the selected proxy groups in his analysis are notably riskier than PSI because of the group members exposure to power market trading and foreign operations. Pub. Ex. No. 8, p. 13.

In doing his DCF analyses, Mr. Kaufman used the Turner Reports for current dividend yields of large publicly held utilities, converting the current yield to a forward yield by multiplying the current yield by $1 + 1/2$ of the Company's expected growth rate. He noted that this conversion methodology has been regularly accepted by the Commission in prior rate proceedings. Pub. Ex. No. 8, pp. 16-17. To estimate the growth rate, Mr. Kaufman employed both historical and forecasted growth rates of earnings, dividends and book value per share, using Value Line as the primary source of growth data. The estimated growth rates that he used were 4.35% for his primary proxy group, 4.18% for Dr. Morin's vertically integrated electric utility proxy, and 2.90% for Cinergy. Pub. Ex. No. 8, p. 18. In an effort to ensure that his analysis was conservative Mr. Kaufman did not include any negative or very low positive growth figures in his analysis. Pub. Ex. No. 8, p. 18. Mr. Kaufman reviewed his estimate of long run growth rates by reference to Reuters Multex.com and CA Turner's Quarterly Dividend Monitor reported data. Pub. Ex. No. 8, p.19.

Mr. Kaufman prepared multiple DCF analyses intended to allow him to cross check results and examine the impacts of alternative data sources. He summarized these alternative analyses in a chart within his testimony that reflects 3 and 6 month average dividend yields:

	3-month	6-month
Value Line (Primary Proxy)	9.09%	9.31%
Multex (Primary Proxy)	9.80%	10.02%
Value Line (Dr. Morin's Proxy)	9.12%	9.43%
Multex (Dr. Morin's Proxy)	9.81%	10.12%
Cinergy (Value Line)	7.94%	8.24%
Cinergy (Multex)	9.71%	10.02%

Mr. Kaufman's initial prefiled range of common equity costs for his DCF methodology ranged from 7.94% to 10.12%. Pub. Ex. No. 8, p. 21. His October Update reflected a narrower range of DCF results from 8.02% to 9.62%. Pub. Ex. No. 8U, Schedule 1, p. 1.

	3-month	6-month
Value Line (Primary Proxy)	9.15%	9.11%
Multex (Primary Proxy)	9.53%	9.49%
Value Line (Dr. Morin's Proxy)	9.17%	9.19%
Multex (Dr. Morin's Proxy)	9.59%	9.62%
Cinergy (Value Line)	8.02%	8.21%
Cinergy (Multex)	9.48%	9.67%

Mr. Kaufman employed the same proxy groups that he used in his DCF analysis and explained that he believes that the CAPM is typically less reliable than the DCF model because of challenges associated with estimating the market risk premium; issues concerning the application of arithmetic versus geometric means; and, controversies surrounding the basis selected for the risk-free return rate. Pub. Ex. No. 8, pp. 23-25.

For his CAPM risk-free rate, Mr. Kaufman reviewed short term, intermediate term and long term interest rates, ultimately using 30-year Treasury securities as an estimate of long-term yields, and giving virtually no weight to short term and intermediate term interest rates. Pub. Ex. No. 8, p. 26. In an effort to produce a result that is more consistent with the long term perspective needed for cost of equity, Mr. Kaufman used both 3-month and 6-month average yields, rather than a spot yield that might subject his results to unreasonable variability. Pub. Ex. No. 8, p. 26.

Mr. Kaufman's CAPM calculations relied primarily upon Value Line's published betas, but he also reviewed and presented two other sources of beta, derived from Security Risk Evaluation by Merrill Lynch and SmartMoney.com. Pub. Ex. No.8, p. 27. A review of the other betas presented by Mr. Kaufman demonstrates that the betas he relied upon were the largest betas from the three sources that he reviewed. Mr. Kaufman calculated both a geometric mean risk

premium and an arithmetic mean risk premium, then averaged the risk premiums, multiplied the average by beta, and combined the product with the risk-free interest rates of long term Treasury securities, producing three CAPM results. Mr. Kaufman supported his use of both the geometric and arithmetic mean risk premium by quoting from a 1982 edition of *Stocks Bonds Bills and Inflation*, by Dr. Roger Ibbotson and from two final orders of this Commission, *People's Gas and Power*, Cause No. 39315, (*Ind. Util. Reg. Comm'n*, October 21, 1992) and *Indiana American Water*, Cause No. 40103, (*Ind. Util. Reg. Comm'n*, May 30, 1996). OUCC Exhibit 8, Kaufman Direct, page 24 line 17 through page 25 line 18. Mr. Kaufman's primary CAPM proxy group relied upon a beta of 0.610, as compared with the average beta for Dr. Morin's proxy group of 0.642 and Cinergy's beta of 0.70. Pub. Ex. No. 8, p. 27.

Mr. Kaufman's CAPM study results are summarized in the following table:

	3 month	6 month
Primary proxy group	7.98%	8.09%
Dr. Morin's proxy	8.15%	8.26%
Cinergy	8.48%	8.59%

Mr. Kaufman's October Update to his CAPM analysis showed the following increases from the results of his direct testimony:

	3 month	6 month
Primary proxy group	8.81%	8.50%
Dr. Morin's proxy	8.79%	8.48%
Cinergy	9.09%	8.78%

Mr. Kaufman's cost of equity ("COE") results in his initial prefiled testimony ranged from 7.94% to 10.12%, with the midpoint of his range at 9.03%. Pub. Ex. No. 8, p. 29. Giving more weight to his DCF results, Mr. Kaufman concluded in his initial prefiled testimony that Petitioner's cost of equity was 9.15%. In his October Update he concluded that cost of equity had increased 10 basis points to 9.25%. Pub. Ex. No. 8U, p. 6, and Pub. Ex. No. 8, p. 29.

Mr. Kaufman indicated on cross-examination that, while his updated recommended cost of equity for PSI increased, the bottom-end of his updated range increased (from 7.94% to 8.02%) and the top-end of his updated range came down significantly (from 10.12% to 9.67%). Tr. at Q86-Q88. Mr. Kaufman also acknowledged that there was no specific numerical weighting assigned by him to arrive at his estimate of cost of equity for PSI. Tr. at Q88. Mr. Kaufman further acknowledged that he basically combined them and reached his ultimate conclusion concerning his recommended cost of equity for PSI. Tr. at Q88.

Mr. Kaufman testified on cross-examination that he believes that his 9.25% cost of equity for PSI should be reduced if this Commission approves PSI's proposed trackers in this proceeding, as trackers serve to reduce risk. Mr. Kaufman explained that he was not

independently testifying to that conclusion; but instead was merely summarizing the testimony of other OUCC witnesses who address the risk mitigation effects of such trackers. Tr. at Q92-Q93 and Q98. Mr. Kaufman clarified on cross-examination that his reference to PSI's proposed trackers that reduce risk, and therefore require a reduction in PSI's cost of equity, do not include PSI's existing: (i) Fuel Cost Charge tracker; (ii) Demand-Side Management tracker; (iii) Construction Work In Progress tracker; or (iv) Sulfur Dioxide Emission Allowance tracker. Tr. at Q93-Q97. Instead, Mr. Kaufman testified that he was only referring to PSI's newly proposed: (i) Nitrogen Oxide Emission Allowance tracker; (ii) Midwest ISO Management Cost and Revenue Adjustment tracker; and (iii) Purchased Power tracker. Tr. at Q97-Q98.²

Mr. Kaufman noted that Dr. Morin's proxy groups contain some electric utilities that were not comparable to PSI. Pub. Ex. No. 8, pp. 36-37. Mr. Kaufman also explained how Dr. Morin's exclusive reliance on forecasted earnings per share in arriving at a growth rate for the DCF method, while ignoring actual growth in dividends per share and book value per share tended to overstate the cost of equity. Pub. Ex. No. 8, pp. 37-38. Mr. Kaufman was also critical of Dr. Morin's method for increasing the actual current dividend yield to a future yield by multiplying the current yield by one plus the Company's expected growth rate, rather than one plus one-half the expected growth rate. Mr. Kaufman supported his one plus one-half growth position by quoting from prior Commission orders and argued that Dr. Morin's full year growth adjustment inappropriately assumes a full year's worth of growth, while a half-year growth adjustment for converting a current yield into a forward annual yield for the DCF model is more appropriate. Pub. Ex. No. 8, pp. 37-39. He was further critical of the fact Dr. Morin's growth rate forecasts were applicable to the next 5-7 years, rather than in perpetuity. Pub. Ex. No. 8, p. 39.

Mr. Kaufman also responded to Dr. Morin's argument that many electric utilities have experienced low or negative growth over the last several years, and criticized Dr. Morin's use of Green Mountain Power's forecasted earnings rate of 19.5% per year. Mr. Kaufman explained that historical data can be used in determining a growth rate for a DCF analysis only if such dramatic "outliers" are removed from the analysis. Pub. Ex. No. 8, pp. 40-42. Mr. Kaufman defended the use of historical data and criticized Dr. Morin's analysis in exhibit RAM-9 which purportedly demonstrates that it is inappropriate to use historical growth rates. Mr. Kaufman noted that many of the companies used by Dr. Morin in RAM-9 are not used by Dr. Morin in his DCF analysis, and contends that if one removes outliers and uses reasonable judgment any concerns about using historical growth rates can be alleviated. Mr. Kaufman added that at the current retention ratios employed by most utilities, the dividend growth rates predicted by Dr. Morin's DCF models are not supportable. Pub. Ex. No. 8, pp. 46-47.

² Mr. Kaufman stated that he had not quantified a specific basis point adjustment to his recommended 9.25% cost of equity for PSI if this Commission approved any combination of those three proposed trackers. Tr. at Q98-Q100. Mr. Kaufman also stated during cross examination that he had asked PSI to quantify the value of PSI's proposed trackers in a data request and that PSI had failed to provide him with a response on that issue. Tr. at Q98.

Mr. Kaufman further criticized Dr. Morin for: (a) relying exclusively on intermediate-term forecasts in earnings per share to estimate the growth rate in dividends for his DCF model; (b) his failure to use historical growth data; and (c) adjusting his DCF models by 20 basis points to account for the quarterly timing of dividends.³ Mr. Kaufman also disagreed with the market risk premium used by Dr. Morin in his CAPM analysis, as well as Dr. Morin's exclusive reliance on the arithmetic mean return to estimate his historic risk premium. Pub. Ex. No. 8, pp. 51 and 53. Mr. Kaufman noted that Dr. Morin's reliance on income returns, rather than total returns, overstates the market risk premium in his CAPM analysis. Mr. Kaufman explained that, while Dr. Morin relies on Ibbotson Associates ("Ibbotson") to support his use of income returns versus total returns, Mr. Kaufman believes that Ibbotson's conclusion is illogical on this point and actually supports a lower, rather than higher, risk premium. Pub. Ex. No. 8, pp. 53-55.

Mr. Kaufman further testified in response to Dr. Morin's estimate of a prospective market risk premium, and explained that Dr. Morin's analysis was based on a DCF model, adjusted to capture a full year's future growth, which overstates the forward yield. Mr. Kaufman indicated that Dr. Morin's model compounds that error by inappropriately adjusting for quarterly timing of dividends. He added that Dr. Morin's aggregate market data produces an unusually high dividend yield of 2.5%, particularly in relation to Value Line's calculated averages of 2.1%. Pub. Ex. No. 8, pp. 55-57. He was further skeptical of Dr. Morin's 2.5% figure because his calculation included non-dividend paying companies, whereas Mr. Kaufman's Value Line data excluded those companies, logically meaning Dr. Morin's results should be lower, not higher, than Mr. Kaufman's. Mr. Kaufman questioned Dr. Morin's exclusive reliance on long-term government yields, as a proxy for his risk-free rate of return, claiming that it is also appropriate to consider other maturities as a proxy for the risk free rate of return. Pub. Ex. No. 8, p. 57.

Mr. Kaufman also responded to Dr. Morin's testimony regarding an upward adjustment to beta for delayed recognition within beta of changes in risk fundamentals. Mr. Kaufman noted that Dr. Morin made a similar argument in PSI's last rate case and indicated that Cinergy's beta has declined since PSI's last rate case. Mr. Kaufman also indicated that he believes that Dr. Morin's ECAPM analysis is redundant, and notes that this type of analysis was rejected by the Commission in PSI's last rate case as the use of adjusted beta already increases beta for companies with a beta that is below 1.0. Pub. Ex. No. 8, p. 64.

With respect to Dr. Morin's RP models, Mr. Kaufman indicated that Dr. Morin's failure to include 2002 data in his risk premium analysis very likely serves to artificially overstate the historical risk premium. Pub. Ex. No. 8, pp. 65-66. He also noted that most of Dr. Morin's RP models were biased as they are based on an arithmetic mean risk premium. Pub. Ex. No. 8, p. 67. Mr. Kaufman further indicated that Dr. Morin's risk premium models do not react to changes in capital markets and should be given little if any weight.

³ Mr. Kaufman noted that the Commission has accepted the quarterly dividend adjustment in prior cases, but indicated that he believes that if this approach is utilized a corresponding downward adjustment should be made to account for the timing of how a utility earns its profits (and invests them during the year). Pub. Ex. No. 8, pp. 48-49.

Mr. Kaufman challenged Dr. Morin's proposed 30 basis point upward adjustment to the cost of equity to account for, what he believes to be, overstated flotation costs. Mr. Kaufman explained that actual flotation costs associated with Cinergy's most recent stock issuance amounted to \$1.55 million, or less than 1% of the stock issue. Mr. Kaufman stated that while he believes that some adjustment for flotation costs is merited, he recommends the adjustment be only 5-10 basis points. Mr. Kaufman stated that the flotation cost adjustment proposed by the OUCC would increase PSI's net operating income ("NOI") by approximately \$1.1 million per year whereas the Petitioner's proposed adjustment would increase PSI's NOI by approximately \$5.5 million per year. Pub. Ex. No. 8, pp. 75-76. Mr. Kaufman noted that the Commission rejected Dr. Morin's overstated estimate of flotation costs in the last PSI rate case, Cause No. 40003. Pub. Ex. No. 8, pp. 75-77.

OUCC witness Timothy Geswein testified regarding the general business risk levels faced by PSI and in response to observations made by PSI witness Rogers regarding industry risks. Mr. Geswein explained that, as a regulated monopoly energy provider, PSI Energy is insulated from many risks and feels few direct impacts from national economic events of the type referenced by Mr. Rogers. He characterized PSI Energy as a "low-risk regulated, franchise monopoly" for which even the Company's regulatory risks have been mitigated.

OUCC witness Dr. Peter Boerger testified in response to Mr. Reising regarding his analysis and discussion regarding PSI's risk profile, and noted that every business faces risks, but that the state's grant of a monopoly service territory to PSI causes electric utilities to be viewed as low risk enterprises despite the factors raised by Mr. Reising. Pub. Ex. No. 5, pp. 3-4. Dr. Boerger also indicated that legislation enacted since PSI's last rate case has favorably affected the Company's risk profile. Changing the Fuel Adjustment Charge ("FAC") earnings test under IC 8-1-2-42.3 has reduced the probability that PSI would return excess earnings to ratepayers, compared to the situation that existed during the last rate case. In 2002, new financial incentive and cost recovery mechanisms for coal-fired investment and related environmental expenditures were enacted within IC 8-1-8.8 that may allow PSI to track increased depreciation and operation and maintenance ("O&M") for its new NOx investments. These legislative changes should be considered as reducing the company's cost of equity below that which would be required in the absence of such legislation. Pub. Ex. No. 5, pp. 12-13.

Dr. Boerger also explained the need to segregate the risks imposed on PSI Energy by its parent in determining the utility's cost of capital. He notes Cinergy's involvement in recent years with relatively risky merchant activities and the role of PSI to sponsor a large power trading operation, explains how Standard & Poors attributed such higher-risk nonregulated activities to both Cinergy and PSI in its publications. Pub. Ex. No. 5, p. 14. Dr. Boerger noted that a substantial share of the risk facing the company has been mitigated, and the cost of that mitigation is being paid already by Indiana consumers. Pub. Ex. No. 5, p. 15.

(3) PSI-IG's Cost of Common Equity Evidence. Michael Gorman testified for the PSI-IG and recommended that PSI's cost of common equity capital should be in the range of 9.7% to 10.3% and that PSI's authorized return on equity in this case not exceed 10%.

PSI-IG Ex. No. 3, p. 2. He based his recommendation on a DCF analysis (10.1%), an RP analysis (9.9%-10.3%), and a CAPM model (9.7%). PSI-IG Ex. No. 3, p. 2. He stated that Cinergy's use of leveraging and entry into more risky power/gas trading and a merchant generation operation had created credit rating pressure on PSI. Mr. Gorman maintained that rates should not be set in a way that will allow PSI to contribute dividends in excess of reasonable levels to its parent company to help accelerate the pay-down of parent company debt related to failed unregulated business investments. PSI-IG Ex. No. 3, p. 3. On cross-examination Mr. Gorman acknowledged that he was not aware of any year since the formation of the Cinergy Corp. holding company structure in which the Cinergy operating companies had funneled up to Cinergy Corp. cash in excess of the Cinergy Corp. annual dividend. Tr. at T35-T36. Mr. Gorman agreed with PSI's proposed capital structure, consisting of common equity, preferred stock and long-term debt, but not short-term debt. PSI-IG Ex. No. 3, p. 7.

Mr. Gorman testified that the *Bluefield* and *Hope* cases have established that the return for a public utility should: (i) be sufficient to maintain financial integrity; (ii) attract capital under reasonable terms; and (iii) be commensurate with returns investors could earn by investing in other enterprises of comparable risk. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that the utility's cost of common equity is the return that investors expect, or require, in order to make an equity investment in the utility. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that it is extremely difficult, if highly impractical, to eliminate all higher equity return component premiums to compensate for deregulated market risks. PSI-IG Ex. No. 3, p. 13.

In doing his DCF analysis and RP estimates for PSI, Mr. Gorman used the group of electric utility companies that Dr. Morin selected for his analysis, agreeing that this group is reasonably comparable to PSI. PSI-IG Ex. No. 3, p. 12, and PSI-IG Ex. No. 3, Schedule 1. In his constant growth DCF analysis, Mr. Gorman relied upon the average of the weekly high and low stock prices over a 13-week period ending July 14, 2003. PSI-IG Ex. No. 3, p. 14. He also used the most recently paid quarterly dividend, as reported in Value Line, which he annualized and adjusted for the next year's growth to produce the adjusted dividend rate that he used. PSI-IG Ex. No. 3, p. 14.

With respect to dividend growth rates, Mr. Gorman relied on a consensus of professional security analysts as a proxy for investor consensus of future dividend growth rate expectations. Mr. Gorman testified that security analyst growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data. He used the average of three sources of growth rate estimates, including Zack's Detailed Analyst Estimates, First Call and Multex.com Investors. The consensus estimate was a simple arithmetic average or mean of surveyed analysts' earnings growth forecasts.

The result of his DCF analyses was a cost of common equity of 10.1%. PSI-IG Ex. No. 3, p. 16. He said that his comparable group average five-year growth rate of 4.65% is sustainable over an indefinite period of time, because it does not exceed the growth rate of the overall U.S. economy, which, is estimated to grow at a rate of 5.6%. According to Mr. Gorman, this represents a ceiling for a sustainable growth rate for a utility over an indefinite period of time. PSI-IG Ex. No. 3, p. 16.

With respect to Mr. Gorman's RP analysis, his first such model estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds over the period 1986 through 2002, using regulatory commission authorized common equity returns for electric utility companies. PSI-IG Ex. No. 3, p. 17. His second equity RP method was based on the difference between regulatory commission authorized returns on common equity and contemporary A- rated utility bond yields, over the period 1986 through July, 2003. PSI-IG Ex. No. 3, p. 17. This analysis, he said, showed an average indicated equity RP of authorized electric utility common equity returns over U.S. Treasury bonds of 4.86%. PSI-IG Ex. No. 3, p. 17 and Schedule 5. Mr. Gorman testified that his average indicated equity RP authorized electric utility common equity returns over contemporary Moody's utility bond yields was 3.43%, and, removing the two highest and lowest premium estimates, produced an equity RP in the range of 3% to 4% over that period. PSI-IG Ex. No. 3, p. 18 and Schedule 6. Using the long-term Treasury bond yield of 5.3% (projected by Blue Chip Financial Forecasts) and an equity risk premium of 4.4% to 5.6%, produced an estimated common equity return in the range of 9.7% - 10.9%, with a midpoint estimate at 10.3%. PSI-IG Ex. No. 3, p. 18. Adding his equity risk premium of 3% to 4% over utility bond yields to the average yield on a utility bond with an A-rating for a 13-week period ending July 11, 2003 of 6.37%, produced a cost rate for common equity in the range of 9.4% to 10.4%. PSI-IG Ex. No. 3, p. 18.

With respect to his CAPM approach, Mr. Gorman started with the Blue Chip Financial Forecasts for projected long-term Treasury bond yields of 5.3% for his risk-free cost rate. PSI-IG Ex. No. 3, p. 20. He used a beta of 0.64 obtained by averaging the group betas for his comparable group of electric utilities. PSI-IG Ex. No. 3, p. 21 and Schedule 8. He derived two market based premium estimates, one forward looking and one based on long-term historical average. He estimated the expected return on the Standard & Poor's ("S&P") 500 by adding an expected inflation rate of 2.2%, to the long-term historical arithmetic average real return on the market. He produced an estimated return of 9.4%. PSI-IG Ex. No. 3, p. 21. The market premium is the difference, he said, between the 11.8% expected market return and his 5.3% risk-free estimate, or 6.5%. PSI-IG Ex. No. 3, p. 21. Using Ibbotson's arithmetic average of achieved total returns on the S&P 500 of 12.7% and the total return on long-term Treasury bonds of 5.7%, produced an indicated equity risk premium of 7.0%. His CAPM estimated return on common equity ranged from 9.5% to 9.8%. PSI-IG Ex. No. 3, p. 22. He concluded that PSI's cost of common equity was in a range from 9.7% to 10.3%. PSI-IG Ex. No. 3, p. 22.

Mr. Gorman was critical of Dr. Morin's original recommendation of an 11.5% cost of common equity. PSI-IG Ex. No. 3, pp. 24-25. Mr. Gorman said that in his CAPM analysis Dr. Morin used a beta of 0.72 which was considerably higher than the actual Value Line beta of 0.65 for his investment grade vertically integrated electric utility companies. His use of a beta higher than his electric utility sample increased his result. PSI-IG Ex. 3 pp. 25-26. Mr. Gorman also took issue with Dr. Morin's 30 basis point adjustment for flotation costs. *Id.* Mr. Gorman also did not accept Dr. Morin's ECAPM analysis. Mr. Gorman testified that that the Value Line beta Dr. Morin relied on to estimate a utility beta is already adjusted for the tendencies of betas lower than one to increase toward a market beta of one over time. Thus Dr. Morin's adjustment is redundant. PSI-IG Ex. No. 3, p. 26.

With respect to Dr. Morin's historical RP analysis, Mr. Gorman was critical of Dr. Morin's achieved return on utility stocks, compared with Treasury securities and utility bond yields. PSI-IG Ex. No. 3, p. 27. He said that the yields on Treasury securities and utility bonds have been depressed by the dramatic decrease in interest rates over the last 20 years. PSI-IG Ex. No. 3, pp. 27-28. He stated further that the achieved returns on the utility stocks and yields on utility bonds over the last several years have been driven by high expectations of large profits produced by competitive operations related to the wholesale market trading and merchant plant development. PSI-IG Ex. No. 3, p. 28. This, he said, gave the indicated equity risk premium a bias upward. PSI-IG Ex. No. 3, p. 28.

Mr. Gorman also took issue with Dr. Morin's computation of an allowed risk premium on electric utilities. He said that Dr. Morin arbitrarily selected the time period 1993 through 2002 to estimate the spread between regulatory-authorized returns on equity and contemporary utility bond yields and Treasury bond yields. Mr. Gorman also questioned the implication in Dr. Morin's approach, that a utility's equity risk increases with decreases in interest rates. Mr. Gorman further testified that he thought that Dr. Morin's additions of an equity risk premium to contemporary utility bond yields may overstate a fair return for regulated utility operations. PSI-IG Ex. No. 3, p. 30. He said that current bond yields are affected by the much higher risk of non-regulated energy markets, and said that the average authorized return on equity above contemporary energy industry bond yields produces a return on equity that may exceed that appropriate for lower risk regulated operations. PSI-IG Ex. No. 3, pp.30-31.

In discussing Dr. Morin's DCF analyses, Mr. Gorman claimed that the information supporting Dr. Morin's analyses was stale and needed to be updated. PSI-IG Ex. No. 3, p. 33. Mr. Gorman criticized Dr. Morin's proposal for a 30-basis point flotation cost adjustment. Mr. Gorman said that PSI should not be accorded flotation costs, because it is a wholly-owned subsidiary of Cinergy and does not sell its stock to the public. PSI-IG Ex. No. 3, pp. 34-35. He added, however, that if it is reasonable to allocate a portion of Cinergy's flotation expenses to PSI, PSI should be required to account for those expenses. PSI-IG Ex. No. 3, p. 35. Mr. Gorman also questioned Dr. Morin's proposal for a 20-basis point adjustment to reflect quarterly dividend compounding, claiming that it provides investors an opportunity to earn the dividend reinvestment return twice, once through the authorized return on equity and a second time when dividends are received by investors and actually reinvested by investors. PSI-IG Ex. No. 3, p. 33.

Mr. Gorman testified that he believes a commission should exercise its judgment, based on the arguments and positions taken by the expert witnesses, in determining the fair rate of return for the utility. Tr. at T27. In this regard, Mr. Gorman indicated that relevant considerations for a commission in determining a utility's fair rate of return include the utility's financial condition, the prospects for a credit rating downgrade for the utility, and the utility's performance in rendering utility service. Tr. at T28-T30. Mr. Gorman further testified that, in determining the fair rate of return for a utility, a commission should be forward-looking and consider business, financial, regulatory, and other issues likely to be experienced by the utility while the rates approved are expected to be in effect. Tr. at T29. Mr. Gorman acknowledged

that the fair rate of return authorized for a utility could be different than the estimated cost of capital for the utility. Tr. at T30-T31.

(4) CAC Evidence on Cost of Equity. Dr. Michael F. Sheehan testified on behalf of CAC and addressed certain factors which are relevant to PSI's risk and ROE. He noted that in regulatory proceedings, risk has a significant impact on the determination of the return on equity and provided an assessment of how the industry and PSI's risks have changed, with specific reference to the many supportive and risk-reducing regulatory structures that have been adopted by this Commission. While Dr. Sheehan did not sponsor specific calculations of risk premiums or adjustments to PSI's return on equity, his testimony provides an overview of PSI's level of risk that is relevant to our overall consideration of the fair return for PSI.

Dr. Sheehan noted that he believes that since PSI's last rate case in Cause No. 40003, Cinergy has adopted a policy of gradually shifting risk from the holding company to PSI ratepayers. This was done through requests for preapprovals of investment expenditures; preapprovals of cost deferrals to subsequent rate cases; and, the adoption of a growing number of trackers, such that much of the revenue requirement is now governed by trackers. CAC Ex. C, p. 31. He explained that the regulatory mechanisms have shifted risks to ratepayers as, without the use of trackers, cost increases occurring between rate cases would have to be absorbed by the utility. With the use of trackers cost increases are automatically passed on to ratepayers in higher rates as they occur. These shifts in risk, according to Dr. Sheehan, argue for elimination of some of the risk premium received by the utility in the ROE determination. CAC Ex. C, p. 33.

Mr. Bruce Biewald also testified on behalf of CAC on the subject of PSI risk exposure and return on equity. Mr. Biewald indicated that the Commission should consider, in determining whether the Company's requested ROE is excessive, the risk reduction effect that has occurred due to the Company's existing and proposed trackers and pre-approved costs; and, whether the approval of the Company's merchant plant acquisition acted to shift risks from Cinergy to PSI customers regarding the investment in those plants. CAC Ex. B, p.7.

Mr. Biewald explained that he believes the Company's various special rate riders and its CWIP tracker have allowed the recovery of 8.4% of its operating income during the test year. CAC Ex. B, pp. 8-9. He noted that in addition to the existing Riders 60, 62, 63, 66 and 67, PSI is seeking approval for new proposed trackers in the form of Rider 68 (MISO), Rider 69 (NOx) and Rider 70 (Purchased Power). CAC Ex. B, p. 9. According to Mr. Biewald, the Company's rate tracking mechanisms effectively reduce its shareholders' exposure to risk in that they: (1) reduce regulatory lag; (2) allow certain significant categories of costs (e.g. environmental costs) that increase to be put into rates without consideration of other, related categories of costs (e.g. cost of capital) that decrease; (3) tend to defer general rate cases with their attendant risks and costs; and, (4) tend to decrease the scope and detail of regulatory review of tracked costs compared to a general rate case. In addition, Mr. Biewald noted, "such riders can, in many situations, greatly reduce volatility of net earnings on a monthly, quarterly and annual basis." CAC Ex. B, p.10.

With respect to Dr. Morin's peer group of utility companies used to calculate his ROE, Mr. Biewald noted that PSI has the highest number of trackers among the 26 utility companies, and is one of only two companies that have trackers for perhaps the four most significant cost categories that are commonly tracked: 1) fuel adjustment; 2) purchased power; 3) environmental cost recovery; and, 4) emission allowances. According to Mr. Biewald's analysis, the large number of PSI's rate adjustment trackers relative to its industry peers suggest that the Company is relatively well protected against many risks to which other utilities are often exposed. CAC Ex. B, p.11

(5) Testimonial Staff's Testimony. In his testimony Mr. Inman indicated that he did not prepare an independent cost of equity study for PSI, choosing instead to analyze the cost of equity estimates of PSI and other parties in the case. IURC Staff Ex. No. 1, p. 3. Mr. Inman agreed with Dr. Morin's 20-basis point quarterly dividend adjustment to reflect the fact that current stock prices, which reflect expected quarterly dividend payments, are lower than the standard DCF result suggests. IURC Staff Ex. No. 1, p. 5. Logic dictates, he said, that an upward adjustment to the standard DCF model would correct the understatement. IURC Staff Ex. No. 1, p. 5. Mr. Inman also testified that, in the DCF model, the current dividend yield must be adjusted to reflect the expected dividend yield. Mr. Inman indicated that there are two common methods which calculate the expected, or forward, dividend yield -- full-year and half-year. Citing recent Commission proceedings, Testimonial Staff recommended use of the half-year method of calculating forward dividend yield. IURC Staff Ex. No. 1, p. 5. Mr. Inman further noted that Dr. Morin's DCF results were higher in his March 2003 prefiled testimony than those produced by other methods of determining the cost of common equity capital.⁴ Mr. Inman stated that Staff's final DCF recommendations begin with Dr. Morin's current yield data and growth forecasts for each of his DCF calculations and adjust for the half-year dividend yield method, a quarterly dividend adjustment and direct flotation costs. IURC Staff Ex. No. 1, p. 7.

With respect to the CAPM model, Testimonial Staff used the February to July 2003 six-month average of 30-year Treasury bond yields to obtain a rate of 4.86%. This average was used to smooth out the recent swings in long-term bond yields. IURC Staff Ex. No. 1, p. 8. By comparison, Dr. Morin used 5.0% in his initial testimony, and 5.3% in his updated testimony. Pet. Ex. G, p. 16; and Pet. Ex. TT, p. 3. Mr. Inman anticipated the higher interest rate in Dr. Morin's update and stated in his September 2003 prefiled testimony that considering the bottoming out of interest rates and the recent upswing in long-term bond yields, it would not be surprising if Dr. Morin chooses to leave his estimate as it is or even revises it upward. IURC Staff Ex. No. 1, p. 8.

Mr. Inman indicated that Testimonial Staff did not dispute Dr. Morin's use of the 0.72 Value Line suggested beta in his CAPM calculations. IURC Staff Ex. No. 1, p. 9. For the market rate of return, Staff agreed with Dr. Morin's use of the period beginning 1926 and extending through the most recent available year as this takes into account nearly all economic scenarios and is most representative of all possible returns. IURC Staff Ex. No. 1, p. 9.

⁴ However, this changed in Dr. Morin's October 2003 update which showed that his October 2003 DCF results were below his October 2003 CAPM and RP results. Pet Ex. G, p. 46; and Pet. Ex. TT, p. 3.

However, while supporting this approach, Mr. Inman observed that Dr. Morin failed to include 2002 data in his calculation of the market risk premium. To adjust for this deficiency, Mr. Inman included 2002 data in his market risk premium calculation to ensure that his calculation accurately reflects data extending through this period. Mr. Inman stated that Testimonial Staff supported giving weight to both the arithmetic and geometric means of computing annual growth rates. IURC Staff Ex. No. 1, pp. 12-13.

Mr. Inman said that Testimonial Staff believes that the proper market risk premium to be used in this case should include total return on long-term Treasury bonds, and not just income thereon. Adjusting Dr. Morin's results for use of total return on long-term bonds, and giving equal weight to the arithmetic mean and the geometric mean market risk premiums, Testimonial Staff arrived at a market risk premium of 5.55%. IURC Staff Ex. No. 1, p. 14. Testimonial Staff used Dr. Morin's 6.1% prospective risk premium, resulting in a CAPM market risk premium input of 5.83%, which produced a CAPM estimate of PSI's cost of common equity of 9.05%. Mr. Inman said that the primary reasons for the 85 basis point difference between Staff's and Dr. Morin's original unadjusted CAPM estimates are: (i) Staff's use of then more current, lower risk-free rates; (ii) Staff's use of lower market risk premium due to inclusion of 2002 data; (iii) Staff's equal weighting of the geometric and arithmetic mean risk premiums; and (iv) Staff's use of 30-year Treasury bond total return. IURC Staff Ex. No. 1, p. 15.

With respect to flotation costs, Staff recommended allowing one-half of Dr. Morin's proposed flotation cost adjustment, which would amount to a 15 basis point adjustment to the CAPM and RP methods, and a 2.5% gross up of the dividend yield produced by the DCF method. IURC Staff Ex. No. 1, p. 17. Testimonial Staff recommended rejection of Dr. Morin's ECAPM calculation on the grounds that the Value Line beta already contains an adjustment of beta, therefore it was unnecessary for Dr. Morin to make a further adjustment of beta. IURC Staff Ex. No. 1, p. 17.

With respect to the RP method Mr. Inman, in conformity with previous Commission orders, adjusted Dr. Morin's RP calculations by equally weighting the arithmetic and geometric mean risk premium, using Dr. Morin's source data. IURC Staff Ex. No. 1, p. 18. Testimonial Staff then adjusted Dr. Morin's flotation costs to allow for direct costs only and updated his 30-year Treasury bond data and A-rated utility bond yields. IURC Staff Ex. No. 1, p. 18. Testimonial Staff accepted Dr. Morin's statistical analyses of hundreds of risk premiums allowed by state regulatory commissions over a 10-year period compared with long-term Treasury bond yields, but observed that Dr. Morin's results do not account for the differences in risk factors that may have been considered by the various state commissions in the hundreds of data points. IURC Staff Ex. No. 1, pp. 18-19. For that reason, Testimonial Staff said, the results of Dr. Morin's allowed RP calculations are questionable. IURC Staff Ex. No. 1, p. 19.

Giving somewhat less weight to the DCF results than Dr. Morin, Testimonial Staff produced lower results, concluding that a reasonable cost of common equity would be in the range of 10.25% to 10.50%, which, as Mr. Inman observed, falls in the lower end of Dr. Morin's suggested range of 10.2% to 13.6%. IURC Staff Ex. No. 1, p. 19. In his oral direct testimony, Mr. Inman updated his reasonable range of cost of equity for PSI to 10.35% to 10.55%. Tr. at

T51-T52. Mr. Inman noted that Staff offered several different weighting mechanisms for consideration to provide this Commission with options based upon previous Commission orders which have given less weight to the DCF method. IURC Staff Ex. No. 1, p. 19. Staff's different weighting mechanisms included a 8%/46%/46% CAPM/RP/DCF (excluding ECAPM) weighting which produced a top-end 10.96% cost of equity, and a 40%/40%/20% CAPM/RP/DCF (excluding ECAPM) weighting which produced a low-end 10.24% cost of equity. IURC Staff Ex. No. 1, p. 20.

Mr. Inman observed that Regulatory Research Associates, Inc. ("RRA") tracks major rate case decisions by state commissions. Mr. Inman testified that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first six months of 2003 was 11.38%, and 11.16% for all of 2002. IURC Staff Ex. No. 1, p. 22. Mr. Inman stated on cross-examination that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first nine months of 2003 was 10.91%, which could be 11% if you excluded the 9.5% awarded to New Jersey Central Power & Light.⁵ Tr. at T106-T107. Mr. Inman observed that Dr. Morin's original 11.5% recommendation falls just above the midpoint, and Staff's recommended range falls in the lower end, of the range RRA reported thus far for 2003. IURC Staff Ex. No. 1, p. 22.

Observing that the determination of an exact investor required return on equity is impossible, Mr. Inman said that finding a range of reasonableness for ROE is more realistic. IURC Staff Ex. No. 1, p. 22. He observed that experts and non-experts alike will agree that the results of the CAPM, RP and DCF methods are driven by the inputs, of which there are countless possibilities and legitimate arguments regarding the appropriate inclusion or exclusion of various inputs. IURC Staff Ex. No. 1, pp. 22-23. Mr. Inman testified that Mr. Gorman also used DCF, RP and CAPM calculations in formulating his cost of equity recommendation of 9.7% to 10.3%, and noted that experts that use different inputs into the same formulas can arrive at different final cost of equity ("COE") estimates. IURC Staff Ex. No. 1, pp. 23-24. Mr. Inman concluded with the observation that, as the Commission has noted in other cases, the Petitioner has recommended a high COE and all opposing experts have recommended much lower COE's. The true COE most probably lies somewhere in between. IURC Staff Ex. No. 1, p. 24.

Mr. Inman stated in his prefiled testimony that PSI's credit rating downgrade risk could increase as a result of this rate case. IURC Staff Ex. No. 1, p. 24. In this regard, Mr. Inman stated that a downgrade of PSI's credit rating would lead to increased debt costs, a reduction in financing options, and ultimately higher costs to consumers. IURC Staff Ex. No. 1, p. 25. Therefore, Mr. Inman testified that it is important to PSI and to its customers that this Commission's final order in this Cause, regardless of the findings on cost of capital and rate of return, recognizes PSI's strengths and position relative to its industry peers. IURC Staff Ex. No. 1, p. 25. Mr. Inman noted that conspicuously absent from Petitioner's case-in-chief testimony was an analysis of the impact of PSI receiving something less than its requested increase, such as

⁵ We note that this August 1, 2003 decision was premised, in large part, in response to quality of service problems of the utility and that the 9.5% was only put into effect on an interim basis. See, 2003 N.J. PUC LEXIS 253 and 2003 N.J. PUC LEXIS 243.

50% or 75%.⁶ Mr. Inman concluded that he believes that approval of a rate increase for PSI which is less than the full amount requested, but is an amount that could still be considered “substantially all” will not endanger PSI’s credit rating. IURC Staff Ex. No. 1, p. 26.

(6) Petitioner’s Rebuttal Evidence on Cost of Equity.

(a) Rebuttal Concerning OUCC’s Cost of Common Equity Evidence. Dr. Morin testified for PSI in rebuttal to the cost of common equity capital testimony submitted by other parties. Dr. Morin observed that Mr. Kaufman’s recommended ROE of 9.15% (prior to being updated to 9.25%) was substantially under the average returns on common equity allowed in the electric and natural gas utility rate cases in the first six months in 2003 of 11.40% and 11.38%, respectively, as reported by RRA in its survey of regulatory decisions dated June, 2003. Pet. Ex. No. FF, p. 15. Dr. Morin also observed that it was well under the average returns of 11.6% and 11.7% allowed on common equity for the utilities in Mr. Kaufman’s sample groups as reported in the Turner Reports survey for September, 2003. Pet. Ex. FF, p. 15. Dr. Morin concluded that Mr. Kaufman’s recommendation was: (a) well outside the zone of currently allowed rates of return for Mr. Kaufman’s comparable companies; (b) well outside the mainstream of recently authorized returns for electric and natural gas utilities allowed by state regulatory agencies throughout the country; and (c) would be among the lowest, if not the lowest, in the country if adopted. Pet. Ex. FF, p. 16.

Dr. Morin testified that he believes that Mr. Kaufman’s dividend yield calculation in his DCF analysis understate flotation costs by 20-25 basis points. Pet. Ex. FF, pp. 16-17. Mr. Kaufman’s flotation cost approach, Dr. Morin observed, assumes that all past flotation costs associated with past securities issues have been recovered, which he said is not the case here. Pet. Ex. FF, p. 17. Because such costs were not expensed in the past, Dr. Morin said, investors should be compensated for flotation costs for the entire time that these initial funds are retained by the firm, on an on-going basis. Pet. Ex. FF, pp. 17-18. In theory, Dr. Morin said, flotation costs could be expensed and recovered through rates as they are incurred. However, this procedure is not considered appropriate here because the common equity capital raised in a given stock issue remains in the utility’s common equity account and continues to provide benefits to ratepayers indefinitely. Pet. Ex. FF, p. 18. He reiterated that unlike the case of bonds, common stock has no finite life, so that flotation costs cannot be amortized and must, therefore, be recovered via an upward adjustment to the allowed return on equity. Pet. Ex. FF, p. 18.

Dr. Morin also disagreed with Mr. Kaufman’s dividend yield calculation in his DCF analysis, because Mr. Kaufman multiplied the current dividend yield by one plus one half the expected growth rate ($1 + 0.5g$), rather than by one plus the expected growth rate ($1 + g$), thereby understating the return expected by the investor. Pet. Ex. FF, p. 19. Dr. Morin explained that the fundamental assumption of the annual DCF model used by Mr. Kaufman is that dividends are received by investors annually, at the end of each year, and that the first dividend is to be received by the investor one year from now. Pet. Ex. FF, p. 19. Instead, he said,

⁶ The Petitioner’s rebuttal evidence did include such a 75% scenario. Pet. Ex. HH, pp. 4-5; Pet. Ex. HH-1; Pet. Ex. GG, pp. 6-10; and Pet. Ex. EE, pp. 5-6.

dividends are received quarterly. Because the appropriate amount of dividends to use in the annual DCF model is the prospective dividend one year from now, rather than the dividend one-half year from now, Mr. Kaufman's approach, Dr. Morin testified, understates the proper dividend yield, thereby understating PSI's cost of equity by approximately 15 basis points. Pet. Ex. FF, p. 19. Dr. Morin emphasized that because the price of a stock reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the compounding of quarterly dividends in the same way that bond yield calculations are routinely adjusted to reflect semiannual interest payments. Pet. Ex. FF, p. 20. By failing to recognize the quarterly nature of dividend payments in his DCF computation, Dr. Morin said that Mr. Kaufman understated PSI's cost of equity capital by about 20 basis points. Pet. Ex. FF, p. 21.

Dr. Morin also disagreed with Mr. Kaufman's use of the average stock price over the past three and six months to derive the dividend yield to use in his DCF. Pet. Ex. FF, p. 23. Dr. Morin indicated that he believes because the analyst is attempting to determine a utility's cost of equity in the future, current stock prices provide a better indication of expected future prices than any other price. Pet. Ex. FF, p. 23. Dr. Morin also took issue with Mr. Kaufman's proxies used to derive his DCF growth rate component, which was an average of all of the rates calculated, using Mr. Kaufman's proxy group. Pet. Ex. FF, p. 24. Dr. Morin reproduced those rates in the following table, based on Mr. Kaufman's Schedule 4:

TABLE 3				
Mr. Kaufman's Growth Rates				
Primary Group of Electric Utilities				
	ALL	Excl DPS	Forecast	Only DPS
	(1)	(2)	(3)	(4)
Historical 10 yr. EPS	3.8%	3.8%		
Historical 5 yr. EPS	4.5%	4.5%		
Historical 10 yr. DPS	2.2%			2.2%
Historical 5 yr. DPS	3.1%			3.1%
Historical 10 yr. BPS	3.1%	3.1%		
Historical 5 yr. BPS	4.2%	4.2%		
Forecast EPS	6.2%	6.2%	6.2%	
Forecast DPS	4.7%		4.7%	4.7%
Forecast BPS	4.7%	4.7%	4.7%	
Multex Forecast EPS	4.9%	<u>4.9%</u>	4.9%	
<u>Turner Forecast DPS</u>	<u>3.1%</u>		<u>3.1%</u>	<u>3.1%</u>
Average	4.0%	4.5%	4.7%	3.3%

Pet. Ex. FF, p. 25.

Dr. Morin said that based on this table the overall average growth rate from all the proxies, as shown in Column 1, is 4.0%, and that the dividend growth proxies average of 3.3% shown at the bottom of Column 4 is an outlier, compared to the average of 4.5% computed by excluding the dividend proxies (Column 2) and compared to the average of 4.7% obtained from

the growth forecast proxies (Column 3). Pet. Ex. FF, p. 25. Dr. Morin testified that historical growth rates are inappropriate proxies for expected growth at this time, as are dividend growth rates, both historical and prospective. Excluding the historical proxies and the outlying dividend growth forecast from Mr. Kaufman's numbers, he said, produced average growth estimates of between 5% and 6%. Pet. Ex. FF, p. 25. Use of a 5% growth rate, he said, would have raised Mr. Kaufman's DCF estimates by at least 100 basis points. A similar bias applies to Mr. Kaufman's estimates derived from his second group of vertically integrated electric utilities. Pet. Ex. FF, pp. 25-26.

With respect to Mr. Kaufman's use, as proxies for the DCF growth component, of historical ten-year and five-year growth rates, Dr. Morin stated that, under circumstances of stability, it would be reasonable to assume that historical growth rates in dividends/earnings influence investors' assessment of the long-run growth rate of future dividends/earnings; however, Dr. Morin concluded that these are anything but stable times in the electric utility industry. Pet. Ex. FF, p. 26. Dr. Morin went on to indicate that historical growth rates are downward-biased by the sluggish earnings performance in the last five years. In addition, Dr. Morin testified that he believes historical growth rates are largely redundant, because such historical growth patterns are already incorporated in analysts' growth forecasts, which, he said, should be used in the DCF model. Pet. Ex. FF, p. 26. Dr. Morin added that published studies in academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations and that investors rely on such forecasts. Pet. Ex. FF, p. 28. These studies, he said, present detailed empirical evidence that the average analysts' expectation is more similar to expectations being reflected in the market place than are historical growth rates. Pet. Ex. FF, p. 28. Based on the foregoing analysis, Dr. Morin recommended that this Commission reject the use of historical growth rates as proxies for expected growth in the DCF calculation in this proceeding.

While Dr. Morin agreed with Mr. Kaufman's proxy used for the risk-free rate in his CAPM analysis, he said that he believes that Mr. Kaufman utilized an understated beta. Pet. Ex. FF, p. 29. He also criticized Mr. Kaufman's use of the geometric average of realized returns in measuring market return, as well as Mr. Kaufman's use of the "plain vanilla" CAPM without adjustment. Pet. Ex. FF, pp. 29-30. Dr. Morin maintained that the problem he saw with Mr. Kaufman's beta estimates of 0.61 and 0.64 for his two samples of electric utilities, is that historical betas are downward-biased estimates of the true risk of electric utilities. Pet. Ex. FF, p. 30. The true underlying beta of electric utilities, he said, has been gradually increasing in past years because of increasing risk for electric utilities. Yet, the historical beta measured over a five-year estimation period lies midway between the true beginning-of-period beta and the current end-of-period beta, seriously underestimating the current beta. Pet. Ex. FF, p. 31. Dr. Morin said that use of a beta of 0.70, rather than Mr. Kaufman's beta of 0.61-0.64, would increase his ROE estimate by approximately 40-50 basis points, assuming a market risk premium in the range of 6.0%-7.0%. Pet. Ex. FF, p. 32.

Dr. Morin maintained that only arithmetic averages are appropriate when measuring investor expected returns and criticized Mr. Kaufman for using geometric, as well as arithmetic, mean returns in his CAPM analysis. Pet. Ex. FF, pp. 32-33. He pointed out that the effect of

using both the geometric and arithmetic mean market risk premiums of 4.7% and 6.4%, rather than the arithmetic mean of 6.4% alone (see Pub. Ex. 8, Schedule 5), was to decrease Mr. Kaufman's estimate of the required market return by 0.90%. Pet. Ex. FF, p. 33. This, in turn, biased his CAPM result downward by some 55-65 basis points, using Mr. Kaufman's beta estimates 0.61-0.64. Pet. Ex. FF, p. 33. Dr. Morin noted that the widely-cited Ibbotson Associates publication from which Mr. Kaufman's market return estimate is derived, and from which Mr. Kaufman quotes in his testimony, contains a detailed and rigorous discussion of why geometric averages should not be used in estimating the cost of capital. Pet. Ex. FF, p. 33. Dr. Morin maintained that performance appraisal is one thing and cost of capital estimation is another matter entirely. In estimating the cost of capital, he said, the goal is to obtain the rate of return that investors expect, that is, a target rate of return. On average, investors expect to achieve their target return. This target expected return is, in effect, an arithmetic average. The achieved or retrospective return is the geometric average. In statistical parlance, the arithmetic average is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean. Pet. Ex. FF, p. 34.

Dr. Morin also disagreed with Mr. Kaufman's sole use of the raw form of the CAPM to estimate the cost of capital. He said that there have been countless empirical tests of the "plain vanilla" CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests, he said, support the conclusion that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. Pet. Ex. FF, p. 37. The result of these observations, he said, is that a CAPM-based estimate of the cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities. He said that Mr. Kaufman's CAPM based estimate understated PSI's equity cost by about 50-60 basis points from this bias alone, as shown by a comparison of Dr. Morin's CAPM and ECAPM studies. Pet. Ex. FF, p. 37.

Dr. Morin also noted that Mr. Kaufman's original ROE recommendation for PSI of 9.15% implies a risk premium of only 3.75% over long-term U.S. Treasury bonds, given that long-term Treasury bonds were yielding about 5.4% in the month of August, 2003. Pet. Ex. FF, p. 39. He said that the implied risk premium over "A"-rated electric utility bonds would be about 2.35%, given that A-rated electric utility bonds are currently yielding about 6.8%. Pet. Ex. FF, p. 39. Dr. Morin cited empirical risk premium literature and evidence that indicates that current risk premiums are much higher, and concluded that the risk premium implied in Mr. Kaufman's recommendation is much lower than generally found in empirical finance literature. Pet. Ex. FF, p. 40.

Dr. Morin did not agree with Mr. Kaufman's view that the market risk premium between stocks and bonds has narrowed over time. Pet. Ex. FF, p. 40. In fact, he stated that he believes the opposite to be true, particularly for the electric utility industry, citing studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992), Carleton, Chambers and Lakonishok (1983), and Maddox, Pippert and Sullivan (1995), who, he said, have demonstrated

that, beginning in 1980, utility risk premiums varied inversely with the level of interest rates, rising when interest rates fell and declining when interest rates rose. Pet. Ex. FF, pp. 40-41. Concurrent with the steady decrease in interest rates in the last decade, he said, utility risk premiums have thus escalated -- not narrowed. Pet. Ex. FF, p. 41. The reason for the inverse relationship, he said, is that when interest rates rise, bondholders, whose interest rates are fixed, often suffer a decrease in the market value of their bonds, experiencing a capital loss. This is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. In order to avoid interest rate risk in an environment of rising interest rates, investors tend to become more willing to undertake equity investment which, although subject to some fear of loss of earning power, is less sensitive to the fear of interest rate risk. Pet. Ex. FF, p. 41. The resulting increase in the supply of funds available for such equity investments causes a downward pressure on the market price for equity. So, generally it is observed that if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. Pet. Ex. FF, p. 41. This is particularly true, he said, in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon, he said, has been termed as a "lock-in" premium. Conversely, in low interest rate environments, he said, as in the case currently, when bondholders' interest rate fears subside and shareholders' fear of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase. Pet. Ex. FF, pp. 41-42. To corroborate this phenomenon further, Dr. Morin said that regulators have, in fact, systematically and correctly increased the authorized risk premium when interest rates declined, and conversely decreased the authorized risk premium when interest rates increased. Pet. Ex. FF, p. 42.

Dr. Morin pointed out that Mr. Kaufman's contention that the market risk premium has declined over time is undermined by his own references, citing the Ibbotson Associates study often quoted in Mr. Kaufman's testimony, which finds no evidence that the market price of risk or the amount of risk in common stocks has changed over time. Pet. Ex. FF, p. 42. Rather, Ibbotson said that there is no significant statistical correlation in successive annual market risk premiums, that is, there is no trend. Pet. Ex. FF, p. 42.

In rebuttal to Mr. Kaufman's criticism of Dr. Morin's ECAPM analysis, Dr. Morin said that he believes that unadjusted raw betas are inappropriate to use in a CAPM analysis because current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Pet. Ex. FF, p. 43. Historical betas, he said, whether raw or adjusted, are only surrogates for expected beta, which is why Value Line and other investment information services report adjusted betas. Pet. Ex. FF, pp. 43-44. He said that one of the most well known results in finance is that a CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities based on the empirical evidence. Pet. Ex. FF, p. 44. The empirical form of the CAPM that he used in his initial testimony, he said, refines the standard form of the CAPM to account for this phenomenon. Pet. Ex. FF, p. 44.

Dr. Morin also rejected Mr. Kaufman's criticism of his use in his DCF analysis of an analyst's earning growth forecast as a proxy for the growth component, pointing out that near-term dividend growth rates cannot be relied upon, as it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years, in response to the gradual penetration of competition in the revenue stream. Pet. Ex. FF, p. 45. Dr. Morin also rejected Mr. Kaufman's claim that additional risks and higher expected returns associated with unregulated activities of electric utility holding companies overstate investors' required returns for their regulated operations. Pet. Ex. FF, p. 47. He pointed out that the energy utilities in his sample groups are largely dominated by their regulated operations and that Mr. Kaufman, himself, included in his proxy groups only those companies with at least 75% of revenues derived from electric utility operations. Pet. Ex. FF, p. 48.

Dr. Morin testified that he believes that Mr. Kaufman's DCF analysis result is understated by 155 basis points: (i) 20 basis points from the omission of an appropriate flotation cost allowance; (ii) 15 basis points from the understatement of growth in the dividend yield component due to the use of the wrong DCF functional form; (iii) 20 basis points due to the use of the annual DCF model rather than the quarterly version; and (iv) 100 basis points from the understated growth rates, mainly the inappropriate use of the dividend growth rates. Pet. Ex. FF, p. 53. Adjusting these numbers in this manner would raise Mr. Kaufman's original DCF range of ROEs from 7.94% - 10.12% to 9.5%-11.7%, Dr. Morin said. Pet. Ex. FF, pp. 53-54.

Dr. Morin concluded that he believes that Mr. Kaufman's CAPM analysis results are understated by 165-195 basis points: (i) 40-50 basis points from the use of an understated beta; (ii) 55-65 basis points from using geometric means instead of arithmetic means in estimating the market risk premium from historical data; (iii) 50-60 basis points from the understatement of expected return inherent in the "plain vanilla" version of the CAPM; and (iv) 20 basis points from the understatement of flotation costs. Pet. Ex. FF, p. 54. Allowance for the understatements would raise Mr. Kaufman's recommended original ROE from a range of 7.98%-8.59% for his CAPM studies to a range of 9.7% - 10.6%. Pet. Ex. FF, pp. 54-55.

(b) Rebuttal Concerning PSI-IG's Cost of Common Equity Evidence. Dr. Morin indicated that he believes that Mr. Gorman's procedures and methodologies are generally sound and in keeping with the practices of finance professionals. Pet. Ex. No. FF, p. 56. He agreed with: (i) Mr. Gorman's sample of electric utilities used in his DCF and CAPM analyses; (ii) his use of analysts' growth forecasts as proxies for expected growth in the DCF model; (iii) his use of long-term Treasury bond yields as proxies for the risk-free rate in the CAPM analysis; (iv) part of his market risk premium component of the CAPM analysis; and (v) the broad outline of his risk premium analysis. Pet. Ex. No. FF, pp. 56-57. He disagreed with Mr. Gorman regarding: (i) the absence of a flotation cost adjustment; (ii) the failure of his DCF model to recognize the quarterly payment of dividends; (iii) the beta estimates used in his CAPM analysis; (iv) part of his market risk premium component in the CAPM analysis; (v) the failure to employ the empirical version of the CAPM in keeping with the vast literature on the subject; and (vi) the failure to account for the inverse behavior between the allowed risk premium and the level of interest rates. Pet. Ex. No. FF, p. 57.

Dr. Morin said that in his opinion Mr. Gorman's dividend yield component in his DCF analysis is understated by 30 basis points as it does not allow for flotation costs, and, as a result, a legitimate expense is left unrecovered. Pet. Ex. FF, pp. 57 and 59. Dr. Morin testified that Mr. Gorman's allegation that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, such as is the case of PSI, ignores the fact that the parent-subsidiary relationship does not eliminate the costs of a new issue -- it merely transfers them to the parent. Pet. Ex. FF, p. 59. Fair treatment, he said, must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred by that utility. Pet. Ex. FF, p. 59.

Dr. Morin said that Mr. Gorman's failure to recognize the quarterly nature of dividend payments in his DCF computation understates his cost of equity capital by about 20 basis points. Pet. Ex. FF, p. 61. He said that Mr. Gorman's use of a 0.64 historic beta for his electric sample understates his results because historical beta measures for an industry in a state of heightened risk are understated. Pet. Ex. FF, pp. 61-62. He observed that use of a more appropriate beta for PSI of 0.70 would raise Mr. Gorman's CAPM estimates by approximately 50 basis points, using Mr. Gorman's market risk premium estimate of 7.0%. Pet. Ex. FF, p. 62.

Dr. Morin believed that, in his risk premium analysis, Mr. Gorman appropriately examined the historical risk premiums implied in the ROEs allowed by state regulatory commissions in hundreds of electric utility ROE decisions over a 16-year period, 1986-2002, relative to the contemporaneous level of long-term Treasury bond yields and A-rated utility bond yields. However, although the average ROE spread over long-term Treasury yields was 4.9% for the 1986-2002 period, Mr. Gorman used a range of 4.4% to 5.6% rather than 4.9%. Pet. Ex. FF, pp. 63-64. Dr. Morin disagreed with the use of this range because of the rising trend of the risk premium in response to lower interest rates, rising competition and restructuring. Pet. Ex. FF, p. 64.

Dr. Morin testified that in his DCF approach, Mr. Gorman did not allow for flotation costs (30 basis points) and employed underestimated dividend yield data (20 basis points), thereby understating PSI's cost of equity by 50 basis points. Pet. Ex. FF, p. 68. He added that Mr. Gorman's CAPM result was further understated by 50 basis points because of his use of the raw form of the CAPM. Finally, he said, a recognition of the rising allowed risk premium over time in response to lower interest rates and rising competition and restructuring, ignored by Mr. Gorman, would have raised his risk premium estimate to above 11%. Pet. Ex. FF, p. 68.

(c) Rebuttal Concerning Staff's Cost of Common Equity Evidence. In his response to Testimonial Staff's original recommendation of ROE allowance in the range of 10.25% to 10.50%, Dr. Morin said he disagreed with Staff's two adjustments to his DCF analysis. Staff used the one-half year $(1 + 0.5g)$ adjustment factor to the dividend yield, rather than the full year $(1 + g)$ factor. Second, Staff reduced his flotation cost adjustment by one half, from 30 to 15 basis points, based on the actual costs reported for Cinergy's most recent stock offering. Restoration of the full flotation cost adjustment and application of the functional form of the DCF model he proposed would raise Staff's original range by 30 basis points from 10.25% - 10.50% to 10.55% - 10.80%. Pet. Ex. FF, p. 70.

Dr. Morin also disagreed with two of Staff's adjustments to his CAPM analysis. First, he said that he believes that Staff's risk-free rate needed to be updated to reflect current capital market conditions. Staff used a 4.9% risk-free rate based on a six-month average of 30-year Treasury bond yields. The yield was in excess of 5% for the months of August and September 2003, Dr. Morin said, and was 5.3% at the time Dr. Morin's rebuttal testimony was prepared at the end of September. Pet. Ex. FF, p. 70. He was also critical of Staff's use of geometric means to measure expected returns. Failure to rely exclusively on the arithmetic mean biased Staff's CAPM result downward by some 55-65 basis points, he said. Pet. Ex. FF, p. 70. He also was critical of Staff's ignoring what Dr. Morin considered the overwhelming empirical evidence that the "plain vanilla" CAPM understates the return on low-beta stocks. Pet. Ex. FF, p. 71.

(7) Discussion and Findings Concerning Cost of Equity Capital Evidence.

Based on the entirety of the testimony presented on this issue, it is apparent that we have been presented with a highly detailed discussion of the cost of equity capital by various parties to this proceeding. In evaluating the evidence presented on this issue we concur with Mr. Inman's observations that: (i) the determination of an exact investor required return on equity is impossible; (ii) the results of the CAPM, DCF and RP methods are driven by the inputs for each, of which there are countless possibilities and legitimate arguments to include this and exclude that; and (iii) a petitioning utility will tend to support methodologies and inputs that support a higher result and those in opposition will tend to support methodologies and inputs which produce a lower result. IURC Staff Ex. No. 1, pp. 22-23. Our discussion and analysis of this issue also serves to illustrate that the goals for setting the fair rate of return for a public utility go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist. With this in mind, we turn our analysis to the cost of capital evidence submitted in this proceeding.

The witnesses testifying concerning Petitioner's cost of capital all used similar approaches. Dr. Morin, Mr. Kaufman and Mr. Gorman, all utilized standard methodologies for determining a cost of common equity capital: DCF studies, the CAPM model, and/or the RP approach. As is typically the case, however, they came to different conclusions. Dr. Morin's updated DCF studies produced a range in the cost of equity from 10.3% to 12.1%. His updated CAPM and RP methods produced costs of equity in the range of 10.9% to 12.5%. Mr. Kaufman, on the other hand, produced lower estimated costs of equity in his updated study, ranging from 8.02% to 9.67% utilizing the DCF methodology, and from 8.48% to 9.09% utilizing the CAPM model. Mr. Kaufman's initial study produced DCF results ranging from 7.94% to 10.12%, and CAPM results ranging from 7.98% to 8.59%. Mr. Gorman calculated a cost of equity in the range of 9.7% to 10.3%, utilizing a DCF analysis, a RP analysis, and the CAPM model. Testimonial Staff witness Inman, analyzing the cost of equity estimates of the other parties, recommended a cost of equity range of 10.25% to 10.50% in his prefiled testimony. Mr. Inman noted on cross-examination that he did not perform a complete update of his analysis; however, as part of his testimony, Mr. Inman provided an updated range of PSI's cost of equity capital from 10.35%-10.55%.

We note that unlike the last PSI rate case in which there was extensive testimony from the experts regarding the strengths and weaknesses of the DCF, RP, CAPM, and ECAPM *models*, the issues in the present cause focus more on the *inputs* utilized in the models, rather than the models themselves. While the parties offer little insight as to why their approach has changed, it is apparent based on our review of the evidence in this Cause that unlike the last rate case in which the DCF model presented lower results compared to the other models, the models utilized in the present proceeding offer a certain level of uniformity in their results. Perhaps this fact alone helped to eliminate any incentive an expert might otherwise have to criticize the results of a particular model as part of this proceeding.⁷ While it is not necessary for us to resolve extensive debate regarding the value and utilization of each of the models, there are disagreements regarding some of the major inputs used by the experts within the various models. While we do not believe that it is necessary for us to address every issue upon which the experts disagreed, we think that it is important for us to review the major areas of disagreement prior to reaching a conclusion on these issues.

The evidence presented in this Cause, on cost of equity issues and the major areas of disagreement among the various experts, is summarized in the following table:

Summary of ROE Estimates and Areas of Disagreement					
	<i>Witness / Party</i>	<i>Morin / PSI</i>	<i>Inman / IURC</i>	<i>Kaufman / OUCC</i>	<i>Gorman / PSI-IG</i>
Original	CAPM	10.20 – 10.70%	9.21%	7.98 - 8.59%	9.50 - 9.80%
	DCF	10.70 – 13.60%	10.42 - 13.52%	7.94 – 10.12%	10.10%
	RP	10.90 – 12.30%	9.69 - 11.02%	NA	NA
	ARP	11.30 – 11.40%	11.30 - 11.40%	NA	9.40 - 10.90%
	Recommendation	11.50%	10.25 - 10.50%	9.15%	10.00%
Updated	CAPM	10.90 – 11.40%	NA	8.48 - 9.09%	NA
	DCF	10.30 – 12.10%	NA	8.02 - 9.67%	NA
	RP	10.90 – 12.50%	NA	NA	NA
	ARP	11.30 – 11.40%	NA	NA	NA
	Recommendation	11.20%	10.35 - 10.55%	9.25%	NA
Major Areas of Disagreement - All Models					
All	Floatation costs Adjustment	0.30%	0.15%	0.05 - 0.10%	0.00%
CAPM	Beta	0.72	0.72	0.65 – 0.70	0.64
	Market Risk Premium Mean "Arithmetic vs. Geometric"	Arithmetic	Both	Both	Arithmetic
	ECAPM	Accept	Reject	Reject	Reject
DCF	Half - vs. Full -Year Div. Growth	Full-Year	Half-Year	Half-Year	Full-Year
	Quarterly Compounding Adj.	0.20%	0.20%	0.00%	0.00%
RP	Risk Premium Mean "Arithmetic vs. Geometric"	Arithmetic	Both	NA	NA

⁷ Only the ECAPM remains as a model subject to any meaningful criticism from the experts in this Cause.

The recommended ROE estimates (as adjusted) presented in this Cause range from 9.25–11.20%, a spread of 195 basis points. Several factors contributed to the variation in estimates including: varying weights applied by the experts to several ROE models; the use of Arithmetic vs. Geometric mean returns; Spot vs. Average T-Bond and dividend yields; and, the wide array of proxy groups used in an effort to replicate PSI's risk profile. While we do not find it necessary to resolve each of the sometimes overlapping disagreements between Dr. Morin, Mr. Kaufman, Mr. Gorman and Mr. Inman, in arriving at either an appropriate cost of capital, or a fair rate of return determination, we note that specific aspects of Dr. Morin's analyses raised concerns on the part of the various other parties and are therefore worthy of additional review and discussion by the Commission.

The Commission recognizes that there were disagreements between the Petitioner and the other witnesses with respect to the following issues: 1) The level, or inclusion, of flotation costs by Dr. Morin (Kaufman, Inman and Gorman); 2) Dr. Morin's failure to utilize the one-half year $(1 + 0.5g)$ adjustment factor for the dividend yield in the DCF model (Kaufman and Inman); 3) the beta estimate utilized by Dr. Morin in his CAPM Model (Kaufman and Gorman); 4) Dr. Morin's use of only the Arithmetic Mean rather than Arithmetic & Geometric mean in his CAPM and/or RP Model (Kaufman and Inman); and, 5) the appropriate inclusion of the ECAPM analysis performed by Dr. Morin (Kaufman, Inman and Gorman). We discuss each of these issues as follows:

(a) Flotation Costs (Applicable to all Models)

In his testimony Dr. Morin cited empirical finance literature to support his conclusion that flotation costs are roughly equal to 5% of electric utility stock offering proceeds. Therefore, with an average expected dividend yield of 5% for electric utility stocks, Dr. Morin concluded that the proper adjustment to the return on equity should be $[5/(1.00-.05)]-5 = 0.3\%$ (thirty (30) basis points). Pet. Ex. G, p. 44.

Mr. Kaufman questioned Dr. Morin's proposed thirty (30) basis point upward adjustment to the cost of equity. Mr. Kaufman took issue with Dr. Morin's use of empirical studies of average electric utility stock issue costs and indicated that the actual flotation costs incurred by Cinergy should be considered when determining a fair flotation cost adjustment. Mr. Kaufman explained that actual flotation costs associated with Cinergy's most recent stock issuance amounted to \$1.55 million, or less than 1% of the stock issue, which Mr. Kaufman contends supports a reduction from the 30 basis points proposed by Dr. Morin. While Mr. Kaufman indicated that he believes that some adjustment for flotation costs is merited, he recommends the adjustment be only 5-10 basis points. Pub. Ex. No. 8 p. 77.

Mr. Gorman indicated that he does not believe flotation costs are applicable to PSI, as the company does not have publicly traded common stock. If Cinergy's flotation costs are applicable to PSI, then PSI should account for them explicitly and not simply add a blanket flotation adjustment as suggested by Dr. Morin.

Testimonial Staff recommended allowing a 15 basis point adjustment to the CAPM and RP methods and a 2.5% gross up of the dividend yield produced by the DCF method. Mr. Inman's flotation cost adjustment is based on Dr. Morin's flotation cost estimate and Cinergy's actual flotation costs related to their most recent stock offering.

Analysis and Findings of the Commission on this Issue

Based on the testimony presented, we are faced with a range of recommendations regarding flotation costs. Mr. Kaufman and Mr. Inman both agree that flotation costs may appropriately be included, albeit at a reduced level from that proposed by Dr. Morin. Mr. Gorman contends that if flotation costs are allowed at all, they should be subject to specific accounting treatment to ensure that only costs incurred by PSI are charged to PSI. The witnesses that favor a reduction or elimination of flotation costs are fairly uniform in their assessment that an analysis of the actual flotation costs incurred by Cinergy should result in a determination by the Commission that a reduction of the upward adjustment proposed by Dr. Morin to account for flotation costs is appropriate.

In undertaking a textbook analysis of the flotation costs issue, Dr. Morin provides a formula that estimates flotation costs that typically might be encountered as part of an electric utility stock offering. While Dr. Morin provides testimony as to why he believes the other witnesses are wrong in proposing to reduce flotation costs, and the impact that such a reduction would have on his proposal, he does not explore the possibility that a reduction of flotation costs could appropriately occur based on the modification of his flotation cost estimate, which does not consider the actual costs encountered by Cinergy. The fact that Dr. Morin's mathematical equation does not overlay fact specific issues applicable to PSI, demonstrates the shortcomings of a formula as it does not include a mechanism to allow the Commission to consider the actual flotation costs encountered by Cinergy as part of recent stock offerings. We believe that our review of this issue would be incomplete without consideration of this very important fact specific issue.

Accordingly, having reviewed the entirety of the record on this issue, the Commission agrees that an adjustment to the return on equity to account for flotation costs is appropriate. We find the recommendations of Mr. Kaufman and Mr. Inman to be particularly instructive on this issue as they both favor a reduction of the flotation costs proposed by Dr. Morin, based on consideration of actual flotation costs incurred by Cinergy. We find this approach to be reasonable and hereby find that a fifteen (15) basis point upward adjustment to the cost of equity to account for flotation costs is appropriate and should be approved in this Cause.

(b) Quarterly Compounding Adjustment and Expected Dividend Yield (DCF Model)

In his testimony, Dr. Morin explained that the common practice of companies is to pay dividends quarterly. Therefore, Dr. Morin indicated that investors' required return must be determined with a DCF model that reflects the quarterly nature of dividend payments. Dr. Morin asserted that an upward adjustment to the return on equity should be made to account for quarterly payment and compounding of dividends, based on the assumption that dividends

received may be reinvested at the return on equity rate. Dr. Morin explicitly adjusted his DCF estimates upward by 20 basis points to account for the quarterly timing of dividend payments.

Mr. Kaufman agreed with Dr. Morin's reasoning, but did not agree that an explicit adjustment should be made to the DCF model. Mr. Kaufman reasoned that utilities receive payments from customers on a monthly basis instead of a yearly basis. This allows the utility to invest their monthly profits in projects that earn a fair return for the utility. However, no downward adjustment is made to the utility's return on equity to account for the monthly timing of these payments. Therefore, Mr. Kaufman concluded that an adjustment should not be made for quarterly payment of dividends. Mr. Gorman testified that he believes that adding the adjustment suggested by Dr. Morin would allow shareholders to earn the dividend compounding return twice, once on the authorized return on equity and the second time when dividends are received. PSI-IG Ex. No. 3, p. 33.

Dr. Morin and Mr. Gorman both used the full-year method to estimate the expected dividend yield. Dr. Morin indicated that he believes that the use of a one-half year adjustment to the dividend yield in the DCF model results in the understatement of the appropriate dividend yield, which in turn results in an understatement of PSI's cost of equity. In contrast to the position set forth by Dr. Morin and Mr. Gorman, Mr. Kaufman and Mr. Inman utilized a one-half year $(1+0.5g)$ adjustment factor to the dividend yield in the DCF model. Mr. Kaufman recognized that Dr. Morin's analysis was based on a DCF model adjusted to capture a full year's future growth, and indicated that he believes this approach overstates the forward yield. Mr. Inman agreed with Mr. Kaufman's criticism of applying the full year's growth to the current dividend yield. Citing recent Commission rate case proceedings, including *In re Indiana American Water Company*, Cause No. 42029 (*Ind. Util. Reg. Comm'n*, November 6, 2002), Testimonial Staff recommended use of the half-year method of calculating forward dividend yields.

Commission Analysis and Findings on these Issues

With respect Dr. Morin's testimony in which he indicates that an adjustment to the DCF model must be made to reflect the quarterly nature of dividends, we note that this issue is not new. This very issue was presented to the Commission in Cause No. 40003, (*Ind. Util. Reg. Comm.*, September 27, 1996). In Cause No. 40003, the Commission found, in resolving a dispute on this issue between the OUCC witness and Dr. Morin, that:

We find the logic of the quarterly DCF a useful alternative, and no sufficiently sound reason has been presented for rejecting it. We find it difficult to believe that the timing of dividend payments is not reflected in the price of a stock. We agree with Dr. Morin that it is inconsistent to use a stock price which reflects quarterly dividends in a model which assumes annual dividend payments unless the model is adjusted to reflect the quarterly dividends which lend to the investor expectations which give rise to the stock price.

While we may appropriately be guided by precedent on this issue, we also find that we could revisit this issue if faced with a persuasive argument. However, the only persuasive argument put forth on this issue was presented by Dr. Morin. Therefore, we again find, based on the evidence presented in this Cause that it would be inconsistent to use a stock price which reflects quarterly compounding of dividends in a model that assumes annual dividend payments unless the model is adjusted to reflect the quarterly compounding of dividends. Therefore, we agree with Dr. Morin on this issue and find that his upward adjustment to the return on equity was appropriately included to account for quarterly payment and compounding of dividends.

With respect to our consideration of forward dividend yield, the Commission is persuaded by the arguments presented by Mr. Kaufman and Mr. Inman in support of their use of the half year method of calculating the forward dividend yield. In reaching this determination we also recognize that we have recently accepted this approach in other proceedings, including Cause No. 42029 (*Ind. Util. Reg. Comm'n*, November 6, 2002), which was referenced by Mr. Inman. In Cause No. 42029 we stated that:

The Commission has considerable experience with the DCF model for estimating the cost of equity. We are well aware of the advantages and limitations of the various approaches used by each of the witnesses. For example, the half-year method used by the OUCC for calculating the forward yield is the most frequently used approach in this jurisdiction and is rarely a point of contention in DCF analysis. We believe it fairly represents the dividend payments expected and received by investors, while the full-year method employed by Petitioner overstates dividend yield.

Cause No. 42029 at 31.

Therefore, based on our review of the specific evidence presented in this case, we find that the proposal set forth by Mr. Inman and Mr. Kaufman to use of the half year method of calculating the forward dividend yield, is appropriate as it fairly represents the dividend payments expected and received by investors. We find that the full-year method employed by Dr. Morin overstates the dividend yield, and is therefore rejected by the Commission in this Cause.

(c) Arithmetic and Geometric Means (CAPM and RP Models)

The application of geometric and/or arithmetic mean risk premiums was an important point of dispute in both the CAPM and RP models in this Cause. Dr. Morin testified that he believes that only arithmetic averages are appropriate when measuring expected risk premiums. Dr. Morin pointed out that the effect of using both the geometric and arithmetic mean risk premiums, rather than the arithmetic mean alone, is to decrease estimates of expected risk

premiums. This in turn, according to Dr. Morin, biases the CAPM and RP results downward. Consistent with Dr. Morin, Mr. Gorman utilized arithmetic averages in the calculation of his risk premiums.

In performing his CAPM analysis Mr. Kaufman averaged his calculated geometric and arithmetic market risk premium means for use as the market risk premium. Mr. Kaufman stated that this approach is consistent with the Commission's past approval of arithmetic and geometric means. Mr. Kaufman directed us to two final orders of this Commission, *People's Gas and Power*, Cause No. 39315, (Ind. Util. Reg. Comm'n, October 21, 1992); and, *Indiana American Water*, Cause No. 40103, (Ind. Util. Reg. Comm'n, May 30, 1996), which he indicated support his conclusion that the use of geometric and arithmetic mean risk premiums are appropriate. Mr. Inman stated that Testimonial Staff agrees with Mr. Kaufman's approach in which he gives weight to both the arithmetic and geometric means when computing the appropriate risk premium means to apply to the CAPM and RP models.

ECAPM and Beta.

Dr. Morin used "plain vanilla" and "empirical" versions of the CAPM. He was the only expert that performed an ECAPM analysis. In his testimony, Dr. Morin asserted that empirical studies have shown that betas tend to converge to unity over time (i.e., historical betas below one are expected to rise to 1.00, and betas above 1.00 are expected to fall to one). Therefore, the use of historical betas necessarily biases a security's market risk downward for a security with a beta less than 1.00. Dr. Morin testified that the ECAPM adjusts beta for its tendency to move to 1.00.

Mr. Kaufman, Mr. Gorman, and Mr. Inman made exclusive use of the "plain vanilla" version of the CAPM and expressly rejected Dr. Morin's use of the ECAPM. Each stated that Value Line (the source of Dr. Morin's beta estimates) adjusts betas for their tendency to move to 1.00 over time. Therefore, the ECAPM analysis performed by Dr. Morin is redundant. These witnesses also noted that the ECAPM model was rejected by the Commission in Cause No. 40003.

While all parties used Value Line as their source for beta estimates in their CAPM models, there was no overall consensus among the experts with respect to the use of an appropriate *estimate* of the beta to be utilized. As with the foregoing issues, the variation in the approaches taken by the experts only serves to further demonstrate that expert opinions will differ with respect to the inputs they utilize--as well as the conclusions they ultimately reach--in undertaking an individual analysis of the issues.

In his testimony, Dr. Morin examined the average betas of two proxy groups: the average of Value Line's reported betas for the electric utility industry, which is 0.71; and, the average beta of Value Line's natural gas distribution universe with a market value in excess of \$500MM, which is 0.72. Based on his evaluation of these two proxy groups, and his assertion that backward looking betas do not fully reflect a company's risk profile, Dr. Motion utilized the higher of the two betas, or 0.72.

While Mr. Inman accepted Dr. Morin's beta of 0.72, Mr. Kaufman and Mr. Gorman both expressed concern regarding the beta utilized by PSI's witness. Mr. Kaufman and Mr. Gorman both rejected Dr. Morin's use of a proxy group of Natural Gas Distribution companies that are not involved in electric operations, as they do not believe that this group can serve as a reasonable proxy for PSI. Based on his analysis of this issue, Mr. Kaufman established a beta of 0.610, for the proxy group that he developed; an average beta of 0.642 based on his review of Dr. Morin's proxy group; and, a beta of 0.70 for Cinergy. Based on this overall review, Mr. Kaufman initially recommended a beta in the range of 0.610 to 0.70. In updating his testimony in this Cause, Mr. Kaufman revised his beta range to 0.65-0.70. Mr. Gorman testified that he used a beta of 0.64, obtained by averaging the group betas for his comparable group of electric utilities.

Commission Analysis on these Issues

The application of geometric and/or arithmetic mean risk premiums has been previously presented to the Commission for consideration. This issue was raised in *Indiana American Water*, Cause No. 40103, (*Ind. Util. Reg. Comm'n*, May 30, 1996), in which the Commission stated:

The debate over the proper use of the arithmetic and geometric means is an issue we consider resolved. As we stated in *Indianapolis Water Company*, Cause No. 39713-39843, each method has its strengths and weaknesses, and neither is so clearly appropriate as to exclude consideration of the other.

Cause No. 40103 at 41.

Mr. Kaufman and Mr. Inman utilized arithmetic and geometric means, while Dr. Morin and Mr. Gorman utilized only arithmetic means. Based on the disparate results from the experts, and consistent with our findings in Cause No. 40103, we find that we must analyze this issue based on our understanding that each method has its strengths and weaknesses, and neither is so clearly appropriate as to exclude consideration of the other.

With respect to the appropriate beta to be utilized, we have been presented with a number of options by the experts regarding this input, ranging from 0.64-0.72. In reviewing this issue the Commission recognizes that the modification of this single input in the CAPM model results in dramatically different proposals regarding the recommended cost of equity. A comparison between Dr. Morin and Mr. Gorman's CAPM analysis, and the beta they utilized, is instructive regarding the impact of this single input. While these two witnesses agreed on many issues, they did not agree on beta. Dr. Morin concluded that 0.72 was an appropriate beta and Mr. Gorman indicated that he believed a beta of 0.64 should be utilized. The difference in this single input, between these two experts, accounted for a swing of 54 basis points and resulted in vastly different outputs from their respective CAPM models. While we do not believe that it is necessary for us to choose a single beta from among those utilized by the experts, we recognize

that this issue is one important factor for us to consider in reaching a determination on an appropriate cost of equity.

With respect to the ECAPM analysis preformed by Dr. Morin we note that the Commission rejected this model in Cause No. 40003, and found that: "the Empirical CAPM is not sufficiently reliable for ratemaking purposes." Cause No. 40003 at 32. We went on to conclude that the ECAPM "...would adjust, in essence, future expectations with regard to investor perceptions of relative risks for further change which may occur years hence." The Commission concluded that "...we do not believe exercises in approximating future cost of capital are conducive to such precise estimation as the Empirical CAPM would suggest." *Id.* We find that nothing presented in this Cause has changed our prior determination that ECAPM is not sufficiently reliable for ratemaking purposes and hereby reject the model in this proceeding.

(d) Other Evidence Relevant to the Determination of a Fair Return

(1) Petitioner's Current Financial Condition and Financial Objectives. PSI witnesses Reising and Esamann testified concerning PSI's current financial condition and financial objectives. Pet. Ex. B, pp. 3-5, and 32-41; Pet. Ex. E, pp. 10-19; and Pet. Ex. DD, pp 3-10 and 27-35. PSI's capital structure on a financial basis as of September 30, 2003 reflects 52.60% common equity, including a \$200 million capital infusion from Cinergy. According to Mr. Reising, PSI's general financial objective is to achieve the fundamentals necessary to provide assured and reasonable access to capital markets in order to continue to provide cost effective, safe, adequate, environmentally compliant and reliable service to its customers. Specific financial objectives necessary to enhance or maintain the desired financial strength include: (1) achieving and maintaining at least a 50% common equity ratio for PSI on a financial capitalization basis; and (2) maintaining PSI's credit ratings at current levels (*e.g.*, an "A-" rating for PSI's senior secured debt), with an ultimate goal of improving PSI's credit ratings one notch (to "A" for PSI's senior secured debt). Pet. Ex. E, pp. 10-11.

With respect to PSI's stated objective of improving its credit rating, Dr. Morin offered an analysis of what he believes the optimal bond rating for an electric utility's senior secured securities should be. Dr. Morin explained that when a company substitutes lower cost debt for equity, the average weighted cost of capital decreases up to a point, while the bond rating progressively deteriorates. Dr. Morin testified that over the long run, a strong "A" bond rating will minimize the cost of capital to customers. According to Dr. Morin, the implication for PSI is clear that long-term achievement and maintenance of a strong "A" bond rating is in both investors' and customers' best interests; and this Commission should establish rates so as to create the financial conditions conducive to PSI achieving an "A" credit rating. Pet. Ex. G, pp. 47-51; and Pet. Ex. FF, pp. 76-78.

Mr. Fetter testified that recent events have negatively impacted the views of credit rating agencies and investors with regard to the utility sector. According to Mr. Fetter, utilities operating within today's financial environment should seek to minimize the uncertainties that could affect a utility's financial health and its credit ratings. Pet. Ex. H, pp. 15-17; Pet. Ex. E, pp. 6-8; and Pet. Ex. EE, pp. 7-8.

Mr. Fetter testified that PSI's securities are currently rated by the three major credit rating agencies as follows:

	<u>Fitch</u>	<u>Moody's</u>	<u>Standard & Poor's</u>
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB+	Baa1	BBB
Junior Unsecured Debt	BBB	Baa2	BBB-
Preferred Stock	BBB	Baa3	BBB-

Pet. Ex. E, p. 12.

In recent assessments of PSI's credit ratings, the three major credit rating agencies have all emphasized PSI's large capital expenditure requirements and the importance of constructive regulatory support. For example, Fitch's August 2001 report stated that "PSI's rising capital requirements related to compliance with environmental regulations and planned new capacity additions is a credit concern and will require regulatory support to prevent a decline in credit quality." Pet. Ex. E, p. 13. Similarly, Fitch's June 2002 report on PSI summarized PSI's key credit concerns as "the relatively high level of capital expenditures needed to comply with environmental regulations and the need for rate increases in Indiana to support the asset transfers." Pet. Ex. E, p. 13. Moody's September 2002 report commented on its rating of PSI as follows: "The rating, however, considers PSI's somewhat high debt load, future capital expenditures for environmental compliance, and financial measures which on a stand alone basis are relatively low when compared to most other companies in their peer rating category." Pet. Ex. E, p. 14. S&P's July 2002 report on PSI addressed certain regulatory challenges facing PSI, including: "uncertainty involving environmental issues related to new source review, as well as the potential for stricter emission standards." Pet. Ex. E, p. 14. Finally, Moody's third quarter 2002 report on PSI noted the following concerns: "PSI's liquidity will continue to be negatively affected by large environmental expenditures for its coal plants and its somewhat high debt load" and "PSI's cash flow has been variable in recent years and generally insufficient to cover dividend requirements and capital expenditure needs." Pet. Ex. E, pp. 14-15.

Mr. Fetter explained that regulation is a key factor in assessing the credit profile of a utility, because a state public utility commission determines rate levels and terms and conditions of service. Investors want to be confident that the utility operates within a stable regulatory environment that will allow the utility the opportunity to earn a reasonable return on its investment while meeting the demand, reliability, service, and environmental requirements of its service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, the strength of its capital structure and moderation of the utility's need to finance externally. Positive consideration is also given to mechanisms that enable rates to be adjusted expeditiously to accommodate major swings in costs which cannot be reasonably forecasted to fit into a standard base rate case proceeding. Pet. Ex. H, pp. 7-10.

Mr. Fetter, along with PSI witnesses Reising and Paul G. Smith, General Manager, Budgets and Forecasts for Cinergy Services, examined several rate increase scenarios and their expected impact on PSI's credit quality. Mr. Fetter initially examined both a "status quo" (*i.e.*, no rate relief) scenario and a full rate relief scenario. He concluded that if the Commission did not approve substantially all of the rate relief requested by PSI, certain key credit ratios for PSI – specifically, cash flow, interest protection, and leverage measures – would significantly decline within a very short period of time. PSI would be reviewed for a possible credit rating downgrade. Pet. Ex. H, pp. 16-22; Pet. Ex. E, p.19; Pet. Ex. F, pp. 3-9; Pet. Ex. GG, pp. 2-10; Pet. HH, pp. 2-5; and Pet. Ex. EE, pp. 3-6.

In rebuttal testimony, PSI and Mr. Fetter analyzed the potential impact of the OUCC's \$18 million rate increase recommendation on PSI's credit quality. Additionally, in response to Mr. Inman's observation that PSI failed to examine alternative rate increase scenarios and their impact on PSI's credit quality, PSI and Mr. Fetter analyzed the potential impact of a \$150 million rate increase on PSI's credit quality.

Mr. Fetter emphasized that a small increase, such as that proposed by the OUCC, would be inconsistent with PSI maintaining its current "BBB+" corporate credit rating status and would preclude PSI from having any opportunity to improve its credit rating. In Mr. Fetter's judgment, given PSI's ongoing need for capital expenditures, under this \$18 million rate increase scenario, credit rating agencies would not only review PSI for a likely downgrade, but might even downgrade PSI two notches. Pet. Ex. GG, pp. 2-6. Additionally, if this Commission authorized a \$150 million annual increase, Mr. Fetter indicated that from a credit quality perspective, PSI would likely be on the dividing line between its current "BBB+" rating and a downgraded "BBB" credit rating. At a minimum, Mr. Fetter felt that serious consideration would be given to a negative watch or outlook if current rating levels were maintained.

(2) Relative Risk Faced by PSI. The various parties in this case held divergent views concerning the risks currently facing the energy industry in general and PSI in particular. PSI's witnesses were of the view that the energy industry is in a highly uncertain state, stemming from a number of extreme and unexpected industry events. Mr. Rogers explained that PSI faces both expected and unexpected challenges. Chief among these challenges is the substantial uncertainty associated with environmental regulation; the ownership, operation, pricing, and reliability of the transmission grid; continuing uncertainty about wholesale market design and operation; and risks associated with achieving fair returns demanded by investors. Pet. Ex. A, pp. 3-4 and 16-29; Pet. Ex. DD, pp. 7-10; and Pet. Ex. EE, pp. 7-8.

Other parties to this proceeding took the view that Indiana's constructive regulatory statutes and policies, combined with the numerous trackers utilized by PSI, effectively mitigate virtually all environmental, transmission, and resource adequacy risks that might otherwise be faced by PSI. As pointed out by Dr. Sheehan, the use of trackers allows for periodic cost adjustments between rate cases and thus eliminates financial risk for a utility. These reduced risks, according to Dr. Sheehan, argue for elimination of some of the risk premium received by the utility in the ROE determination. CAC Ex. C, p. 33. Mr. Biewald shared Dr. Sheehan's

conclusion and observed that, of Dr. Morin's peer group of utility companies used to calculate his ROE, PSI has the highest number of trackers. Mr. Biewald indicated that the large number of PSI's rate adjustment trackers, relative to its industry peers, suggest that the Company is well protected against many risks to which other utilities are often exposed. CAC Ex. B, p.11.

Testimonial Staff also recognized that PSI is protected from certain risks by its use of trackers. Dr. Borum indicated that Indiana law and the rate adjustment tracking mechanisms proposed by the Company give PSI the flexibility to address future challenges and mitigate future uncertainties in a constructive manner. However, he observed, this flexibility and mitigation is achieved by shifting much of the uncertainty and the associated risks to ratepayers. Such shifting of risk must be recognized and reflected in the Commission's decision regarding the cost of equity capital. IURC Staff Ex. No. 3, p. 5. Therefore, Dr. Borum concluded that we should feel comfortable approving a ROE on the lower end of the range recommend by Mr. Inman.

Mr. Kaufman shared the concerns expressed by other witnesses and recommended that his proposed cost of equity should be reduced if the trackers requested by PSI in this Cause are approved. While we do not accept Mr. Kaufman's invitation to reduce his proposed cost of equity, clearly the trackers PSI has requested are an important consideration vis-à-vis our overall consideration of risks faced by PSI and our determination of an appropriate cost of equity.

(3) PSI's Operational Performance. PSI presented evidence concerning its operational and financial performance, and encouraged this Commission to consider its performance in this rate setting process. Specifically, PSI urged this Commission to determine a fair return for PSI based on the higher end of the cost of equity range to reward the company for its performance in terms of reliability, efficiency, cost competitiveness, and customer service. Both Mr. Rogers and Mr. Esamann argued that rewarding strong performance represented good public policy. Dr. Borum of the Testimonial Staff opined on cross-examination that rewarding strong performing utilities through the rate setting process, and in particular in the determination of a fair return for the utility, was consistent with good public policy. Dr. Borum also testified that he believed that PSI was a strong performer in terms of the various attributes that make up customer service – reliability, efficiency, cost-competitiveness, etc. Pet. Ex. B, pp. 11-31; Pet. Ex. DD, pp. 10-21 and 31-34; Pet. Ex. FF, pp. 78-80; Pet. Ex. GG, pp. 19-20; Tr. at E39-E43, E106-E109, E118-E119 and R98-R99.

PSI presented evidence demonstrating that its electric delivery system performed reliably in terms of the frequency and duration of customer interruptions, and outage restoration, and had relatively low O&M costs as compared to peers. While cautioning that individual service territory characteristics make comparisons in this area difficult, Mr. Esamann testified that, in 2002, the average number of sustained interruptions for the year per customer, known as the Electric System Average Interruption Frequency Index ("SAIFI") (including severe storm impacts) was 1.57, and the average time to restore power after an interruption, known as the Electric Customer Average Interruption Duration Index ("CAIDI") (again including severe storm impacts) was 1.81 hours. In 2003, PSI's overall average SAIFI and CAIDI results remained

good, even including the effect of an extended period of severe weather in July. Pet. Ex. B. pp. 20-23; Pet. Ex. M, pp. 59-63; and Pet. Ex. DD. p. 32.

The evidence also shows that PSI provides quality customer service, at competitive costs, as measured by both external and internal customer satisfaction measurements. According to the most recent J.D. Power and Associates customer satisfaction studies, Cinergy and PSI finished in the top quartile for overall residential and midsize business customer satisfaction. In both surveys – residential and midsize business – Cinergy ranked #2 overall in the Midwest region. PSI's own surveys of its residential customers indicate that 89% of responding customers are "satisfied" or "very satisfied" with PSI's customer service. At the same time, PSI's customer service cost per customer is slightly below the ECAR investor-owned utility average. Pet. Ex. B, pp. 27-31; and Pet. Ex. DD, pp. 31-32.

C. Ultimate Findings Regarding Fair Rate of Return for Petitioner. As we have discussed, the courts have emphasized that the determination of a fair rate of return is the prerogative of this Commission, taking into consideration all of the evidence. Our primary objectives in determining a fair rate of return for PSI are to determine a return which is reasonably sufficient to: instill confidence in the financial soundness of the utility; allow PSI to maintain and support its credit ratings; and, to enable PSI to raise the money necessary for the proper discharge of its public utility responsibilities. We have also examined a number of qualitative factors relevant to the determination of a fair return for PSI, specifically: PSI's financial condition and financial requirements; PSI's credit quality; risks facing PSI and the mitigation of those risks through the use of trackers; and PSI's performance as a utility. We find as follows with regard to these important qualitative factors.

First, we find that PSI has continuing, significant financing requirements – a minimum of \$600 million of capital expenditure needs during 2004 and 2005. Next, we find that PSI's current credit quality is investment grade (a BBB+ corporate credit rating), but that the lack of substantial rate relief in light of PSI's current and continuing capital investments could potentially result in a downgrade. The prospect of a downgrade or a negative credit outlook – and the accompanying impact on PSI's ability to access financing on reasonable terms – could be significant given PSI's ongoing financing needs. Further, we find that today's energy industry presents numerous risks, perhaps especially to Midwestern utilities that are heavily reliant on coal.

The expert testimony in this Cause presents us with a range of options with respect to our determination of an appropriate cost of equity. As noted previously, the recommended estimates presented in this matter range from 9.25 – 11.20%, a spread of 195 basis points. Mr. Kaufman's proposal fell at the low end of the range, as he recommended a cost of equity of 9.25% and prefaced this recommendation with a recommendation that this percentage should be reduced if this Commission approves PSI's proposed trackers in this proceeding. Dr. Morin came in with the highest recommended cost of equity of 11.2%. The cost of equity proposed by Mr. Gorman and Mr. Inman fell within the range established by Mr. Kaufman and Dr. Morin. Consistent with our analysis of the specific inputs and issues in dispute, we recognize that it is not necessary for us to agree or disagree with the specific inputs or overall cost of equity proposed by any single

expert. Rather, our determination regarding the appropriate cost of equity in this matter should be a product of our evaluation of the entirety of the evidence presented on this issue by the various parties.

In the present case, PSI presented their proposed cost of equity of 11.2%, as consistent with the cost of equity approved for most other electric utilities throughout the country. Implicit in this approach is the view that proposals that are lower than that proposed by PSI should be rejected by the Commission as outside of the norm. Dr. Morin testified that Mr. Kaufman's recommended ROE of 9.15% (prior to being updated to 9.25%) was substantially under the average returns on common equity allowed in electric and natural gas utility rate cases in the first six months in 2003 of 11.40% and 11.38%, respectively. Pet. Ex. FF, p. 15. While Dr. Morin was quick to criticize Mr. Kaufman's proposal, conspicuously absent from his own analysis is any consideration of the impact that PSI's requested trackers have (or should have) on his proposed cost of equity.

The use of trackers is a significant issue that distinguishes PSI from other electric utilities, and was subject to much discussion in this Cause. While we recognize PSI's strong performance as compared to many of its industry peers, and believe that the ROE approved in this case reflects our positive assessment of PSI on this issue, the inescapable fact is that *trackers reduce risk* to a utility and PSI has many more trackers than its peers. Therefore, we must--in reaching our determination regarding an appropriate cost of equity--properly consider the effect these trackers have in reducing risk, to ensure that these reduced risks are properly reflected in the cost of equity approved by the Commission.

Under these circumstances, we recognize that our determination may not readily allow for the side-by-side comparison of PSI's cost of equity to that of its peers, as advocated by Dr. Morin. However, we also recognize that PSI's decision to utilize trackers, coupled with the divergent options of the experts regarding the various inputs used in the models presented in this matter, has made our decision on the cost of equity issue very fact specific. Because of this, any attempt to make a generalized comparison between the cost of equity approved in this case, and the cost of equity approved for other electric utilities, will undoubtedly fail, unless the comparison fully and carefully reflects the fact specific issues that underlie the basis of our decision on this issue.

Therefore, based on the entirety of the evidence on this issue, including consideration of the Company's performance, in terms of customer service quality, reliability, efficiency, cost-competitiveness, the results contained in well respected customer satisfaction studies, and the risks faced by PSI, we find that it is appropriate to consider the efficiency and quality with which the utility is managed and the utility's overall performance in our determination of a fair rate of return for the utility. Accordingly, based on our review of the testimony presented by all of the parties, and consistent with our analysis of the specific issues disputed by the parties referenced in the our foregoing discussion of these issues, the Commission is persuaded, that the evidence in this proceeding supports an authorized cost of equity capital for PSI of 10.5%. Therefore, we find for purposes of this Cause, that PSI's cost of common equity capital should be 10.5% and its overall cost of capital is 7.30%, computed as follows:

<u>Description</u>	<u>Capitalization</u> <u>(in thousands)</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
Common Equity	\$1,603,374	44.44%	10.50%	4.67%
Preferred Stock	42,333	1.17%	6.11%	0.07%
Long Term Debt	1,402,254	38.87%	6.37%	2.48%
Deferred Income Taxes	519,273	14.39%	0.00%	0.00%
Unamortized ITC - 1970 & Earlier	193	0.01%	0.00%	0.00%
Unamortized ITC - 1971 & Later	30,571	0.85%	8.53%	0.07%
Customer Deposits	9,741	0.27%	6.00%	0.01%
Total	<u>\$3,607,739</u>	<u>100.00%</u>		<u>7.30%</u>

Having determined the cost of capital we must now determine a reasonable fair rate of return for Petitioner. Given that the Commission's determination of Petitioner's fair value rate base of \$4,856,532,000 includes inflation, a comparable amount of inflation must be removed from the rate of return to reach a determination regarding the fair rate of return. The removal of inflation from the cost of equity and/or from the weighted cost of capital provides a reasonable fair rate of return. The inflation factors as provided by OUCC's, witness Mr. Kaufman in Attachment 1, of his testimony, reference inflation from the Consumer Price Index ranging from 1.5% to 3.0%. To determine a range for the fair rate of return, inflation was removed from the cost of equity as a first determinant, and then from the weighted cost of capital. Therefore we find that a reasonable fair rate of return is in the range of 4.30% to 6.63%

6. Operating Income at Present Rates.

A. General. For the 12 months ending September 30, 2002, PSI's jurisdictional operating income from its electric utility operations on a going level basis; adjusted for changes which were fixed known and measurable at the time of the hearing; and, which occurred during the test year, or on or before September 30, 2003, was shown by PSI to be as follows:

Operating Revenues (including CWIP)	\$1,284,140,000
Operating Expenses and Taxes	
Fuel Expense	378,286,000
Purchased & Exchanged Power Expense	9,519,000
Other Operation and Maintenance Expense	391,580,000
Operating Revenue Deduction	(28,917,000)
Depreciation and Amortization Expense	218,316,000
Taxes Other than Income Taxes	58,415,000
Federal and State Income Taxes	<u>69,215,000</u>
Total Operating Expenses and Taxes	<u>\$1,096,414,000</u>
Net Operating Income	<u><u>\$187,726,000</u></u>

Pet. Ex. OO-3, updated October 31, 2003.

This represents a rate of return on original cost depreciated rate base under present rates of 5.13%.

B. Undisputed Pro Forma Adjustments. PSI proposed a number of *pro forma* adjustments to its operating income, per books, which were undisputed. It proposed other adjustments that, though disputed at some point in the process of this rate case, were compromised or were no longer in dispute at the conclusion of the Evidentiary Hearing in this Cause. All such *pro forma* adjustments proposed by PSI, either as originally proposed and undisputed, or as compromised with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed herein. The disputed adjustments are hereinafter discussed.

C. Disputed Pro Forma Revenue Adjustments. In making our determinations regarding an appropriate level of operating expenses to be used in setting Petitioner's rates, we are guided by our overall objective of achieving a level of expenses which are representative of probable future experience. The Indiana courts have emphasized the importance of viewing test year results and out of period adjustments in the context of estimating a representative ongoing level of utility expenses. See, e.g., *City of Evansville v. Southern Indiana Gas & Electric Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 575, in which the Court stated that: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." In the matter of *L.S. Ayres & Co. v. IPALCO et al.*, 169 Ind. Ct. App. 652; 351 N.E.2d 814, p. 820, the Court stated that: "test-year results are relevant for a determination of utility rates only to the extent that past operations are representative of probable future experience. . . . [I]f future operations will be required to bear higher tax rates or higher levels of wages and salaries than were incurred during the test year, test-year data must be adjusted to reflect increased costs." With these guidelines in mind, we turn to an examination of the disputed pro forma revenue and expense adjustments at issue in this case.

In this Cause, PSI proposed a Summer Reliability Tracker to allow the Company to adjust its rates to reflect the fluctuating cost of purchased power necessary to meet reserve requirements, and PowerShare® costs during the months of June through September. PSI's proposal included an offset to these summer expenses in the form of crediting the adjustment with a portion of annual off-system sales profits. Because this proposed mechanism tracked the off-system sales profits from a zero base, PSI made adjustments to remove retail and wholesale non-firm revenue and expenses from its test period income statement.

The Summer Reliability Tracker and its components; Trading Expenses, Purchased Power and PowerShare® costs, are discussed in detail later in this order. We will begin with a discussion of the off-system sales adjustment.

(1) Off-System Sales Profits. As part of its Summer Reliability Tracker PSI proposed to adjust its rates for purchase power costs during the months of June through September. PSI's proposal included an offset to these expenses in the form of crediting the adjustment with a portion of annual off-system sales profits. Because this proposed mechanism

tracked the off-system sales profits from a zero base, PSI made adjustments to remove retail and wholesale non-firm revenue and expenses from its test period income statement. Through its Summer Reliability Tracker, PSI initially proposed to flow back to its customers 100% of its June through September off-system sales profits, plus 25% of its off-system sales profits earned in the non-summer months (October through May). Mr. Esamann testified that he believes off-system sales profits, like purchased power costs, are variable, can be substantial, and are ultimately unpredictable. He proposed to use a tracking mechanism for such credits to customers, rather than trying to build an ongoing level into base rates. Pet. Ex. B, p. 58. Modifying its initial proposal that its customers be credited with 100% of off-system sales profits achieved during the summer months and 25% of such profits achieved during the eight non-summer months, PSI ultimately proposed a 50-50 sharing of profits throughout the year. Pet. Ex. DD, pp. 25-26.

The OUCG opposed PSI's Summer Reliability Tracker and proposed instead that test period off-system sales profits of \$18.7 million or some other reasonable *pro forma* projection be reflected as a credit to PSI's revenue requirements. Pub. Ex. No. 6, p. 16; Pub. Ex. No. 2, p. 28. PSI-IG witness Phillips concurred with the OUCG and indicated that he believed that customers should be credited with the profits from off-system sales in PSI's base rates. Testimonial Staff witness Cvengros testified that while the test year shows approximately \$18 million in off-system sales, the Commission could instead choose to utilize a tracking mechanism, comparable to PSI's current purchased power tracker in the amount of \$13 million, with or without a sharing mechanism for profits exceeding the amount in base rates.

As discussed in greater detail below, the Commission is persuaded that PSI's off-system sales profits are highly variable and therefore are appropriate for tracking treatment. In addition, the Commission hereby finds that PSI's approximate test period off-system sales profits in the amount of \$18.7 million should be recognized in base rates, as discussed below.

(2) Rate Migration.

(a) PSI Proposal. PSI proposed an adjustment to reflect lost revenues from customer migrations in its power rate schedules. Testifying in support of the adjustment, PSI witness Bailey observed that any time rates are redesigned or modified to produce a different revenue requirement, there is a potential that specific customers may be better off under a different rate schedule than the one under which they are currently billed. Pet. Ex. BB, p. 7. The Company's analysis in this case showed that 1,537 accounts would migrate from Rate LLF to Rate HLF, resulting in a \$3,233,000 net revenue loss. *Id.* Its analysis further showed that the migrations from Rate HLF to LLF will involve 410 customers, with net lost revenue of \$3,419,000, for a total of \$6,652,000 in lost revenues from customer migration. *Id.* The Company's experience, he said, indicates that, even with notification, only about 50% of customers will actually migrate. Accordingly, PSI reduced the total amount of potential revenue loss by 50% to \$3,326,000. This amount was proportionally allocated to the two power rate schedules and used to develop the Company's revenue requirements. *Id.* In addition, as PSI's proposed phasing-in of rate design allows an opportunity to determine the actual number of migrations, the Company proposed to limit the amount to be recovered in Phase II rates to the

actual effects of the migrations. *Id.* PSI further proposed to reconcile actual lost revenue due to migrations during Phase I to the amount included in rates. Any difference would be returned or charged to customers through one of the Company's standard contract riders. *Id.* at 7-8.⁸

(b) Kroger Position. Kroger opposed Petitioner's migration revenue adjustment, and indicated that PSI's potential for revenue losses from customers switching rate schedules is an ordinary risk of business under current rates. Kroger Ex. No. 1, p. 24. Kroger's witness Mr. Higgins argued that revenue impacts from customers who switched rate schedules prior to the test year cutoff are already included in the Company's proposed revenue requirements, and there is nothing in this case that changes the fundamental relationship between HLF and LLF. So, he contended, there is no reason to reward PSI with additional revenues on the speculation that customers, who have not previously seen fit to change their rate schedules, will suddenly do so now. *Id.*

(c) PSI Response. In response to Mr. Higgins' testimony, Mr. Bailey testified that PSI has strived to provide customers with rate options, among them being rates that reflect more than just differences associated with voltage level, but also rate options relative to their load factor. It would make little sense, Mr. Bailey observed, for PSI actively to identify and notify customers of potential savings if the only end result for PSI was a reduction in revenue. Pet. Ex. SS, pp. 14-15. PSI contends the proper course is to notify customers of potential savings and allow a known, quantifiable revenue shortfall to be reflected in rates. Mr. Bailey rejected Mr. Higgins' contention that nothing changes the relationship of HLF and LLF in this case, pointing out how much additional revenue could be potentially lost solely as a result of incorporating the effects of the rate increase into the rate design. *Id.*

(d) Discussion and Findings. We find that PSI's proposed rate treatment associated with expected migrations is reasonable as the procedure provides rate options to affected customers, which allows them to select rates most favorable to their respective operations. In addition, the Company indicated that it makes an extensive effort to notify customers of potential bill savings, and that the phased-in rates provide an opportunity to "true-up" the estimated migrations to actual. In conjunction with the phased adjustment, actual migrations will be known prior to the second phase, so the revenue impact can be readily determined. This revenue figure can then be used to develop Phase II rates, and any over-or under-recovery of funds from Phase I rates can be reconciled. As PSI is seeking a dollar for dollar recovery of funds lost through rate migrations--no more and no less—we find that PSI will not be financially rewarded by this adjustment. Therefore, we find that, in this instance, this adjustment is reasonable and is hereby approved.

⁸ Mr. Bailey observed that for a customer to be considered in the Company's migration analysis, the customer must be able to save at least five percent on its annual bill or have the potential to save at least \$600 annually. *Id.* at 8. Mr. Bailey testified that the Company planned to notify customers following an order in this Cause detailing the potential bill savings. It will follow this letter with a personal telephone call if needed and a personal visit in some cases. *Id.*

D. Disputed Pro Forma Expense Adjustments.

(1) Depreciation Expense.

(a) Rates.

(i) Evidence. PSI proposes to increase its annual depreciation accrual by \$79,088,000, for a total *pro forma* annual depreciation expense of \$233,022,000, Pet. Ex. X-21, Sch. C-3.36 (as updated by Pet. Ex. OO-3), based on a traditional depreciation study prepared by Mr. John J. Spanos, of Gannett Fleming, Inc. Mr. Spanos testified for PSI, and began his testimony by defining depreciation as the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of the utility plant in the course of service from causes that can be reasonably anticipated or contemplated against which the Company is not protected by insurance. As examples of such causes, Mr. Spanos cited wear and tear, decay, exposure to the elements, inadequacy, obsolescence, change in demand and the requirements of public authorities. Mr. Spanos' depreciation study was presented in Pet. Ex. T-1.

Mr. Spanos stated that he utilized the straight line remaining life method of depreciation with equal life group procedures. He testified that annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered costs of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner. Pet. Ex. T, p. 7. Mr. Spanos determined his recommended annual depreciation rates in two phases. First, he estimated the service life and net salvage characteristics for each depreciable group. Then he calculated the composite remaining life and annual depreciation rates based on the service life and net salvage estimates determined in the first phase.

With regard to the first phase, Mr. Spanos stated that his service life and net salvage study consisted of compiling historical data from records related to PSI's plant, analyzing this data to obtain historic trends of survival and net salvage characteristics, obtaining supplementary information from management and operating personnel, interpreting that data and forming judgments of average service life and net salvage characteristics. He analyzed the Company's accounting entries that recorded plant transactions during the period 1956 through 2001. These transactions included additions, retirements, transfers, sales and the related balances. Mr. Spanos utilized the retirement rate method to analyze this service life data. He stated this method is most appropriate because it determines the average rate of retirement actually experienced by the Company during the period of time covered by his study.

Mr. Spanos applied the retirement rate method to each different group of property, using the retirement rate method to form a life table, which, when plotted, shows an original survivor curve for that property group. *Id.* at 9. Each original survivor curve, according to Mr. Spanos, represents the average survivor pattern experienced by these several vintage groups during the experience band study. He said that the survivor patterns did not necessarily describe the life characteristics of the property group. Therefore, he must interpret the original survivor curves in

order to use them as valid considerations in estimating service life. He utilized the Iowa type survivor curves to perform these interpretations.

Mr. Spanos made field reviews of PSI's properties in September, 1999 and April, 2002. The purpose of his field review was to allow him to become familiar with Company operations and obtain an understanding of the function of the plant; the reasons for past retirement; and, the expected future causes of retirement. *Id.* at 10. Mr. Spanos estimated the net salvage percentages by incorporating the historical data for the period 1989 through 2001 and considering estimates for other electric companies. He also utilized the demolition cost estimates prepared by Sargent & Lundy and sponsored by PSI witness Mr. Alan Wendorf.

As to the second phase of his study, in which he calculated the composite remaining life and annual depreciation rates, Mr. Spanos testified that he calculated annual depreciation rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. His calculations of annual depreciation accrual rates were developed as of September 30, 2002. *Id.* at 11. Mr. Spanos stated that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage value, in equal amounts to each year of remaining service life. As to the equal life group procedure, he stated the property group is subdivided according to service life. The relative size of each equal life group is determined from the property's survivor curve. This procedure eliminates the need to base depreciation on average lives. The full cost of short lived units are accrued during their lives leaving no deferral of accruals required to be added to the annual cost associated with long lived units. He further stated that the equal life group procedure allocates the capital costs of a property group to annual expense in accordance with the consumption of the service value of the group.

PSI witness Alan Wendorf, Executive Vice President of Sargent & Lundy, LLC, ("S&L") testified regarding the results of a study that estimated the cost of dismantling certain PSI generating stations. Pet. Ex. U, p. 2. Mr. Wendorf testified that in its study S&L made several assumptions with respect to the decommissioning of PSI's plants. For example, they assumed that the only thing necessary to decommission an ash pond was to pump it dry and cover the ash pond with approximately two feet of soft soil. They also assumed that there was sufficient room on site to dispose of all the non-hazardous debris and that there was sufficient fill material on site to cover all this debris. *Id.* at 3. They also assumed that tens of thousands of feet of underground pipe and electrical conduit could be left in place and it would not be necessary to fill in the cooling lake at the Gibson Generating Station. In Mr. Wendorf's opinion, many of these assumptions were conservative and minimized dismantling cost numbers -- *i.e.*, the estimated costs represent the lower end of potential dismantling costs.

Mr. Wendorf estimates of the net cost of dismantling each of PSI's generation stations in 2002 dollars are: Gallagher Generating Station - \$23,691,800; Wabash River Generating Station including the PSI portion of the Wabash River Repowering project - \$33,698,900; Cayuga Generating Station - \$37,544,000; Gibson Generating Station - \$118,434,500; Edwardsport Generating Station - \$12,376,200; and Noblesville Generating Station - \$7,554,000. *Id.* at 6. The details of these estimates are contained in Mr. Wendorf's exhibits, Pet. Ex. U-1 through U-6.

Mr. Michael Majoros testified for the OUCC and indicated that before the Commission allows the current recovery of a future dismantlement cost, it should ensure that such cost will in fact be incurred. He said it is doubtful PSI will dismantle plants unless the Company plans to install new plants at the same site and location as the retired plant. In these circumstances Mr. Majoros said that if there were dismantling costs, such costs should be part of the cost of a new plant. In his opinion, based on the probability of actual plant dismantlement for PSI, Mr. Wendorf's dismantlement estimates should be excluded in their entirety in determining depreciation rates in this proceeding. Pub. Ex. No. 9, p. 20.

Mr. Majoros said that he believes that the underlying premise for including dismantling costs is false. In his opinion it is doubtful that PSI will ever dismantle any of its generation plants to "Greenfield" conditions. Based on his observations during his own plant tour, he concluded that the Company has no plans to even retire these plants, let alone dismantle them. He noted that the retired boilers that he observed had been retired in place, yet this was the largest component of Mr. Spanos' dismantlement costs. *Id.* at 18 Mr. Majoros also relied on a nationwide survey conducted by his firm of steam generating units exceeding 50 MW that have been retired since 1982. According to Mr. Majoros, as of the date of his testimony, 64% of the retired generating units contained in the nationwide survey were retired in place, not dismantled. *Id.* at 19. Finally, Mr. Majoros indicated that PSI has not recorded any final retirements for any electric generating units or plant sites in the last 15 years, and other than Henry County, has no legal obligation to dismantle any of its plants. Mr. Majoros observed that it is unreasonable to assume that PSI, or any other utility, would spend \$700 million to dismantle its production plants, absent a legal obligation to do so. *Id.* at 18-19.

Mr. Majoros went on to state that Mr. Spanos' approach projects substantial past inflation into the future. Thus, he said, Mr. Spanos' future net salvage rates for all other accounts are inflated future net salvage ratios. In Mr. Majoros' opinion, this results in excessive costs of removal charges because the inflated ratios charge current ratepayers for future inflation that has not occurred. Mr. Majoros calculated that over the most recent five years, PSI has only experienced \$7.1 million in negative net salvage on average. This number, he said, should be contrasted with Mr. Spanos' recommendation of \$54.2 million annual recovery of negative net salvage. *Id.* at 24.

Mr. Majoros disagreed with Mr. Spanos regarding the incorporation of future net salvage and terminal net salvage values in depreciation rates. Mr. Majoros indicated that he believes the incorporation of future net salvage and terminal net salvage values increase depreciation rates and inflate estimates of costs that will probably not be incurred. Mr. Majoros also stated that six (6) of the Company's proposed lives in the transmission, distribution and general plant function are too short, thereby overstating the associated depreciation expense. Pub. Ex. No. 9, p. 4. Mr. Majoros proposed a substantially lower annual depreciation expense primarily based on his conclusion that net salvage value should be ignored. *Id.* at 5.

Mr. Majoros also disagreed with Mr. Spanos' use of net salvage ratios in his depreciation rate calculation. He said that this issue is significant, because Mr. Spanos essentially capitalized

costs the Company has no real obligation to incur and then inflated those costs. Mr. Majoros complained that Mr. Spanos was less than forthcoming about how he utilized Mr. Wendorf's cost study. *Id.* at 17. He said that Mr. Wendorf's cost studies were estimates made in terms of 2002 dollars. He said that even though Mr. Spanos stated he relied on Mr. Wendorf's studies, the figures from Mr. Wendorf are not traceable to Mr. Spanos study. Instead, he said, Mr. Spanos applied net salvage ratios to plant balances which resulted in substantially greater amounts of dismantlement costs than estimated by Mr. Wendorf. Mr. Spanos' equivalent numbers exceed \$700,000,000, which means, Mr. Majoros contended, that Mr. Spanos inflated Mr. Wendorf's estimates. *Id.* at 18.

Mr. Majoros went on to discuss the Statement of Financial Accounting Standards ("SFAS") No. 143. He said that pursuant to this accounting standard, all companies, including PSI, must determine whether or not they have an actual legal obligation to dismantle and/or remove retired assets. Pub. Ex. No. 9, p. 25. These legal obligations are called "Asset Retirement Obligations" ("AROs"). If the Company does have an ARO, the net present value of the cost of removal is capitalized and included in the cost of the asset and depreciated over the life of the asset. It is not included as a negative net salvage ratio in depreciation rate calculation, as proposed by Mr. Spanos, but rather, it is added directly to the cost of the assets. He stated that if a Company does not have an ARO, future costs of removal are not considered as a cost of the asset and, therefore, should not be included in the company's depreciation expense on its general financial statements. Mr. Majoros stated that under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to conduct a review to determine if they have any AROs. PSI, he said, conducted such a review and had quantifiable AROs of \$6,890,212. *Id.* at 27.

Mr. Majoros then went into a discussion of the life study methods. He stated that Mr. Spanos used two basic methods. The life span method and the retirement rate actuarial method. In addition to these methods Mr. Majoros also used the geometric mean turnover ("GMT") method. *Id.* at 50. Mr. Majoros testified that he did not disagree with Mr. Spanos' use of the life span method, but did disagree with his application of the method because Mr. Spanos included negative future net salvage in his calculations.

Mr. Majoros also discussed the production life depreciation calculations performed by Mr. Spanos. He said these calculations were predicated on the life method. Based upon his own calculations and independent studies, Mr. Majoros accepted Mr. Spanos' terminal retirement years for steam and other production functions and found them to be reasonable. *Id.* at pp. 52-57. With regard to transmission, distribution and general functions, Mr. Majoros concluded that some of the accounts analyzed by Mr. Spanos utilized service lives that were too short. In particular, Mr. Majoros objected to the service lives used by Mr. Spanos for account 354, 356, 365, 366, 367 and 397. Pub. Ex. No. 9, p. 60. As to vintage amortization accounting Mr. Majoros only disagreed with the five years Mr. Spanos proposed for Account 391.1, office furniture and equipment -IT systems. Mr. Majoros recommended a 10 year amortization for this account. *Id.* at 64.

Mr. Majoros then described an analysis to identify the amount of past collections of non-legal AROs included in PSI's accumulated depreciation account and two alternative versions for

a specific going forward allowance. As to the former, he stated that Mr. Spanos estimated the amounts to be \$281 million as of December 31, 2002. Mr. Majoros said that this amount represents money charged to ratepayers in the past for which PSI has no legal cost or obligation. *Id.* at 36-37. With regard to his proposed going forward allowance, he stated that non-legal AROs included in depreciation expense should be included in a specifically identifiable allowance and should be accounted for separately in depreciation expense and accumulated depreciation accounts. He described his first alternative as an allowance calculated in much the same manner as the Company allowances for legal AROs. For this calculation, Mr. Majoros used Mr. Wendorf's 2002 net present value amount for production plants. For transmission, distribution and general plant, he used Mr. Spanos' future net salvage proposal and estimated remaining life to determine the net present value of these amounts. He stated that the annual allowance using this method is \$3.3 million.

Mr. Majoros' preference is to use his second alternative, a five year rolling net salvage allowance approach which has been used by other administrative agencies such as the New Jersey Board of Public Utilities; the Pennsylvania Public Utility Commission; the Missouri Public Service Commission; and, on a trial basis by the Kentucky Public Service Commission. *Id.* at 45-50. Mr. Majoros characterized this as the Pennsylvania Public Utility Commission's normalized net salvage allowance approach. This approach is based on the average of the most recent five years worth of actual net salvage activity shown in PSI's depreciation study. *Id.* at 38. He said that the net salvage is treated just as any other normalized expense, except that it is charged to accumulated depreciation. He said that the normalized net salvage allowance amount under this proposal is \$7.1 million. Mr. Majoros concluded this portion of his testimony by stating that the Commission should reject PSI's net salvage amount of \$54.2 million and substitute his preferred normalized allowance of \$7.1 million.

The PSI-IG presented the testimony of James T. Selecky with regard to depreciation. Mr. Selecky stated that he supports excluding net salvage from the development of the calculation of book transmission, distribution and general depreciation rates. In his opinion, the net salvage expense should be included in the revenue requirement as a cost to serve as an operating expense, and not a component of depreciation rates. PSI-IG Ex. No. 2, p. 4. Mr. Selecky stated that the annual net salvage component of depreciation expense that PSI is requesting is significantly greater than PSI's actual net salvage expense. In fact, he states, the level of expense as proposed by PSI is approximately six times greater than the historical level typically incurred by PSI on an annual basis. He said that the consequences of PSI's proposed treatment of net salvage are that it unnecessarily raises rates for today's ratepayers and produces inter-generational inequities by shifting cost burdens to today's ratepayers from future ratepayers.

Mr. Selecky stated that PSI's proposed depreciation expense for transmission, distribution and general plant contains an annual net salvage component of \$23,460,000. However, PSI's average actual annual net salvage expense over the last 10 years was a negative \$3,879,000 and over the last 5 years PSI's net salvage expenses averaged a negative \$3,737,000.

Mr. Selecky stated that the large difference between net salvage expense proposed to be included in depreciation rates and PSI's actual net salvage expense in recent years is due in part

to the fact that proposed net salvage percentages included in the development of depreciation rates include estimates of future inflation and may not capture the economies of scale that would occur if large retirement activity occurred during a single year. Also, net salvage ratios included in depreciation rates, he contended, may be developed from limited retirement experience that is not typical. *Id.* at 7. Mr. Selecky stated that under PSI's methodology, if an asset with a service life of 50 years is retired in 2000, PSI compares the cost to remove the asset in 2000 dollars with the installed cost of the asset which, in this case, was measured in 1950 dollars. As a result, the net salvage ratio is developed in costs stated in dollars from different time periods. While the cost of the asset and the cost to remove the asset are stated in nominal dollars, the net salvage ratio provides an estimate of future inflation. As the result, according to Mr. Selecky, PSI's net salvage percentages require today's ratepayers to pay estimated costs of future inflation based on historic trends.

Mr. Selecky proposes that this Commission eliminate the net salvage ratio from the development of depreciation rates and include a net salvage provision as an operating expense. He recommends that a 10 year average actual net salvage expense be included as an operating expense in PSI's total cost of service. *Id.* at 10. He states that two other commissions have adopted this approach -- the Pennsylvania Utility Commission and the Missouri Public Service Commission. He proposed a reduction of \$23,460,000 in depreciation expense and an increase of \$3,879,000 in operating expense.

Mr. Selecky also claimed that the use of an inflation factor applied to Mr. Wendorf's dismantling studies was inappropriate in that this would require today's customers to pay for inflation that may not occur. Mr. Selecky developed his own net salvage ratios for production plant. *Id.* at 18. In developing his proposed ratios, he excluded switchyard costs and contingency costs from the ratios. In his opinion, switchyard costs represent the costs associated with non-steam production investment and it would be inappropriate to recover these costs in depreciation rates developed for steam plant. He removed Mr. Wendorf's contingency because he believes it does not represent a true cost, and, he maintained that as more plants are dismantled, one would expect technological improvements over 2002 technology. This resulted in a proposed reduction to the steam production depreciation expense of approximately \$28,038,000.

Mr. Selecky also opposed PSI's use of the equal life group ("ELG") procedure and recommended that the Commission order PSI to revert to the use of the Average Life Group ("ALG") procedure to develop depreciation rates. Mr. Selecky claimed that use of the ELG procedure results in increasing the depreciation rates in the early life of an asset and implies a precision for allocating consumption of assets that does not exist. PSI-IG Ex. No. 2, p. 28.

Laura L. Cvengros, Assistant Director of the Electricity Division, for the Commission, also presented testimony with respect to depreciation. Ms. Cvengros performed a "reality check" on how PSI's \$84 million depreciation adjustment was derived. IURC Staff Ex. No. 2, p. 3. She reviewed the depreciation study sponsored by Mr. Spanos and compared that depreciation study to PSI's current depreciation rates. PSI current depreciation rates are based on the testimony and exhibits presented by the OUCC, which resulted of a settlement in a prior PSI rate case, Cause No. 39584 that carried the rates forward into PSI's last rate case, Cause No. 40003.

Ms. Cvengros testified that she compared various components of PSI's depreciation study with similar components of the OUCC's depreciation study in Cause No. 39584. Staff compared the net salvage ratios proposed by Mr. Spanos in this proceeding with those used by the OUCC and found them to be consistent except for five accounts. IURC Staff Ex. No. 2, p. 12. She also found that, generally, the average service lives used by Mr. Spanos in his study were longer than those used by the OUCC to develop PSI's current depreciation rates. Ms. Cvengros explained that the general lengthening of average service lives for most accounts would have the effect of reducing the depreciation expense for those accounts. Ms. Cvengros concluded that Staff does not believe that the increased depreciation expense in this Cause was caused by significant changes in methods/procedures from the depreciation study used to set PSI's current depreciation rates, and recommended that the Commission approve PSI's proposed depreciation rates. *Id.* at 9 and 13.

Mr. Spanos testified in rebuttal to the testimony of Messrs. Majoros and Selecky. He first discussed why the ELG procedure should be preferred to the ALG procedure. He opined that the ELG procedure, contrary to Mr. Selecky's opinion, can be viewed as an accurate form of book depreciation. Pet. Ex. II, p. 2.

In Mr. Spanos' opinion, the ELG procedure correctly matches depreciation expense of the straight line allocation of service value over the period the assets are in service and avoids the back-end loading of the ALG procedure. Under the ALG procedure, he observed, the depreciation for each property group is based on the average service life of the account or vintage. As a result of using an average, the cost of short term lives is not fully accrued by the time of their retirement and the service value of long lived items is more than fully accrued in order to make up for the under accruals of the short lived items. Mr. Spanos testified that the ELG method has been known to experts for many years but its widespread use was constrained by the large amount of computation required. Because the ALG procedure can be readily performed, it became the choice of experts by default prior to the use of computers due to ease of understanding. *Id.* at 3. With the advent of modern computer equipment, however, this constraint has been removed and this procedure, which is more accurate, is available to all companies.

Mr. Spanos stated that his service life estimates were based on a number of factors, including judgment. *Id.* at 8. According to Mr. Spanos, Mr. Majoros should have incorporated other considerations and made better use of industry data. Mr. Spanos stated the retirement rate method is the most commonly used life analysis when age retirement data are available. It develops historical indications of the rate of retirements by age intervals. The Geometric Mean Method, included in Mr. Majoros analysis, was used many years ago according to Mr. Spanos, to analyze un-aged data before the development of the simulated plant record method. It is no longer used to analyze un-aged data and was never used when age retirement data was available.

Mr. Spanos then discussed Mr. Majoros' use of industry data. *Id.* at 9. Although Mr. Majoros presented several statistics, Mr. Spanos stated he used only the maximum life or the upper limit as a measure of the reasonableness of his estimate. This use of the maximum

recorded lives, in Mr. Spanos' opinion, is not appropriate. According to Mr. Spanos, the purpose of comparing the results of statistical analysis with other electric utilities' data is to ascertain whether the results fall within a range of reasonableness. Typically, when defining the range of reasonable service life estimates for an account, Mr. Spanos excludes several estimates of both the low and upper end of the range. In contrast, Mr. Majoros relied on the very longest service lives used in the industry to justify his estimates, Mr. Spanos observed. Mr. Spanos described in detail a number of examples where he believes Mr. Majoros inappropriately used industry data. *Id.* at 9-11. Due to these problems, Mr. Spanos concluded that all the bases used by Mr. Majoros are flawed and his recommendations as to survivor curve estimates must be rejected. *Id.* at 12.

In response to the recommendations of Mr. Majoros and Mr. Selecky with regard to net salvage for accounts other than production, Mr. Spanos indicated that these witnesses have proposed a radical change in the basis for determining PSI's allowance for net salvage for transmission, distribution and general plant. He noted that Mr. Majoros also proposed this treatment for the production plant accounts. *Id.* at 13. Their proposal is that the net salvage be removed from the calculation of depreciation and be included as an operating expense. Mr. Spanos characterized this proposal as one of net salvage costs incurred in the past, related to retired plant that served customers in the past, to be collected from current customers in the same manner as current operation and maintenance expense is collected. *Id.* at p.13.

Mr. Spanos was not aware of any authoritative text on the subject of depreciation that supports their proposal to expense net salvage costs. He stated that the two depreciation texts most often cited by depreciation experts as authoritative support the traditional approach that he used here. Addressing Mr. Majoros' statement that state commissions have adopted his approach, Mr. Spanos said that the Pennsylvania Commission does use the five-year net salvage amortization, because it was required to under a 1962 court order interpreting a Pennsylvania statute. Mr. Spanos agreed that the Missouri Commission adopted the Majoros approach in a case. He noted, however, that Mr. Majoros failed to mention that this approach was not used in a later case by the Missouri Commission but, rather, the traditional approach used by Mr. Spanos in this matter was used. As to the two Kentucky cases cited by Mr. Majoros, Mr. Spanos stated that the two utilities were small cooperatives that did not maintain detailed records of costs of removal and gross salvage by account. In other Kentucky cases where the utility maintains detailed records of net salvage, as PSI does, Mr. Spanos noted the traditional methodology had been used. He concluded, by stating that 47 state utility commissions use the traditional method of incorporating net salvage in determination of annual depreciation rates. *Id.* at 15.

Mr. Spanos stated why it is more appropriate and equitable to recognize net salvage costs during the life of the plant. He said the net salvage value cost of an item of plant is part of its service value and, therefore, is part of the item's cost of providing service. That cost, he said, should be collected from the customers that receive the service. Thus, an allocable portion of the net salvage costs should be recovered each year from the customers receiving the value of the service rendered by the item of plant. *Id.* at 15-16. In his opinion, this approach is equitable in that the customers are responsible for the costs of plant that provides them with service. In contrast, Mr. Spanos said, expensing net salvage after the item has been removed from service recovers an entire element of an item's cost of service from customers who do not receive service

from that item, or if a customer has received service from the Company for a number of years, that customer has received only a portion of the item's service value. These results are not equitable, he contended, and violate the principle that customers should pay the cost of plant that serves them.

Mr. Spanos also disagreed with the position of Mr. Selecky and Mr. Majoros that net salvage costs for accounts other than for production plant that may occur in the future should not be collected from customers until they occur. Mr. Spanos testified that the amount of net salvage that should be included in the annual cost of service, and collected from current customers, is a portion of the net salvage related to the current plant in service as a result of allocating these costs to each year of service rendered by the plant. The amount should not be limited only to the current net salvage costs. Current net salvage costs are related to plant that previously rendered service. *Id.* at 18. Mr. Spanos stated that allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accord with sound ratemaking principles. In his opinion, delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service, and as a result of the delay of recovery, also results in higher revenue requirements.

Mr. Spanos said that the current net salvage accruals are larger than current salvage costs because current cost experience is related to plant retirements that largely come from an older plant base that was constructed to serve fewer customers, while current net salvage accruals relate to plant presently in service that serves a much larger customer base. *Id.* at 23. In his opinion, it is appropriate for PSI to recover amounts for future net salvage costs that are greater than the amounts currently expended for such costs because the amount that PSI spends for plant additions is far greater than the amount it proposes for recovery of original costs. For example, according to Mr. Spanos, in the year 2001 PSI total plant additions were over \$236,000,000. Adding the net salvage costs of \$6.5 million for that year to this amount results in a total expenditure of over \$240 million in 2001. This total expenditure is approximately \$60 million greater than the proposed level of depreciation expense that includes recovery of past original costs and future net salvage costs. *Id.* at 23. In Mr. Spanos' opinion, basic equity requires that customers pay for the service value, original cost less net salvage of the plant, from which they receive the service. The fact that this results in accruals for net salvage that are greater than the current experience is neither unfair nor unusual. It is reality, according to Mr. Spanos.

In response to Mr. Majoros' discussion of SFAS 143 and FERC Order 631, Mr. Spanos stated these accounting pronouncements do not control ratemaking. *Id.* at 24. He said that, in general, GAAP in recent years has moved away from the matching principle in favor of an asset and liability based approach for purposes of improving potential investors' ability to ascertain a company's financial condition. Mr. Spanos said blind compliance would set standards for ratemaking purposes that would violate principles of customer equity by expensing the cost of retiring plant, resulting in charges to today's customers for plant that served past customers. Mr. Spanos added that although utilities may not have a legal obligation to remove plant, they nevertheless do so on a regular basis and will continue to do so in the future.

Mr. Spanos also testified that it is not appropriate to develop net salvage percents for production plant based on the estimated costs of dismantling in current dollars as Mr. Selecky did. Pet. Ex. II, p. 28. He stated that the net salvage costs to be recovered from current customers are those costs that will be incurred when the plant currently providing service is retired. Mr. Spanos escalated the dismantling cost developed by Mr. Wendorf to the year of probable retirement as a factor to be considered in the estimation of net salvage for production plant account. Mr. Spanos stated that the use of current dollar amount to cover future dismantling costs will result in under recovery and customer inequity. Mr. Spanos also considered the indication of net salvage developed from historical retirements, most if not all of which represent interim retirements, and compared these results to the escalated costs from Mr. Wendorf's dismantlement studies. The historical data, he said, also supports the net salvage percent that he has estimated for the accounts. He said that the net salvage percents that he developed result in an estimate of future net salvage costs that are less than the sum of the probable future net salvage costs related to both interim and final retirement. *Id.* at 29.

Mr. Spanos also stated, contrary to Mr. Selecky's position, that it is appropriate to expect that costs of dismantling will escalate at a rate of 3% per year. He noted the long term inflation rate as measured by the Consumer Price Index has averaged approximately 3%. He noted that the Handy Whitman Index for all steam production plant has increased at an average rate of 5.1% during the past 30 years. Therefore, in his opinion, it is more likely the dismantling costs will escalate at a rate greater than 3%.

Mr. Wendorf also presented rebuttal testimony on behalf of PSI. He first discussed Mr. Selecky's exclusion of the contingency factor that Mr. Wendorf included in his demolition estimate. Mr. Wendorf stated that this contingency factor was intended to cover unknowns and that experience teaches that almost every complex project, such as demolition of a generation station, ends up with unknowns. Many unknowns do not become apparent until detailed engineering proceeds immediately prior to actual demolition activities and still others will not be identified until actual demolition activities commence. *Id.* at 2.

Mr. Wendorf noted that his estimates assumed that all underground piping, electric duct and foundations would remain in place, an unlikely event if the sites are reused. Mr. Wendorf looked at the resulting increased costs for one station, Cayuga, if these assumptions were changed. If below ground items have to be demolished and moved, PSI would have to backfill the voids and the debris would have to be disposed off-site. This simple change, according to Mr. Wendorf, results in a significant increase (over \$15 million) in the estimated cost to demolish the Cayuga station. This change alone is approximately double the 25% contingency (\$8,139,000) included in the demolition estimates which Mr. Selecky removed. *Id.* at 4.

In response to the position of Mr. Majoros, that his estimates assume returning the sites to a "Greenfield" condition, Mr. Wendorf stated that a key assumption in his demolition estimates was that PSI would not have to remove the contents at the ash ponds at the stations. He assumed that the ash ponds at all these stations could be pumped dry and covered with two feet of soil and seeded. He stated that, contrary to the position set forth by Mr. Majoros, the use of two feet of soil to cover several years of bottom and fly ash does not constitute a return to a Greenfield

condition. Pet. Ex. JJ, p. 5. Mr. Wendorf investigated what it would cost if PSI were required to remove and dispose of all stored ash from the existing ash pond at Cayuga to an off site landfill designed to contain the material in an environmentally acceptable manner. He assumed that such a landfill could be required and constructed within 10 miles of the Cayuga site. Changing this assumption about ash removal according to Mr. Wendorf, would add more than \$100 million to the estimated cost of demolishing the Cayuga site. *Id.* at 5. Mr. Wendorf sponsored an exhibit detailing his analysis and that exhibit demonstrates that the incremental costs of demolishing the Cayuga station would be at least \$155 million as compared with the original demolition cost estimate of \$37,544,000. *Id.* at 6. He believes that the demolition estimates that he has developed in this proceeding are conservatively low with the 25% contingency factor included.

In response to Mr. Majoros' conclusion that, as certain boilers have been retired in place, PSI will never dismantle these plants to Greenfield conditions, Mr. Wendorf indicated that the only retired in place boilers on the PSI system are the recently retired boilers at Noblesville and the Wabash River Unit 1. *Id.* at 7. The turbines associated with all three of these boilers are still in service as part of the Noblesville Repowering Project or the Wabash River Coal Gasification Repowering Project. This situation is entirely different from a completely retired plant, he observed. Removal of these boilers while the remainder of the plant continues in operation would be a very complicated and expensive matter, with no real benefit, since there are interconnecting pipelines and electrical cables located in the area of this boiler which are still in use. Before demolition could begin on a single boiler it would be necessary to determine which of these pipelines and cables would have to be protected, terminated, capped or rerouted to allow continued operation of the remaining units. This process would require extensive engineering and field investigatory work. *Id.* at 8.

Mr. John Roebel was the Company's final rebuttal witness on the subject of depreciation. He responded to Mr. Majoros' assertion that PSI will not dismantle certain generating stations at the end of their useful lives. Pet. Ex. KK, p. 2. Mr. Roebel stated that, in his opinion, demolition will take place, because it is the reasonable thing to do. He stated that he believes that PSI will dismantle these stations in order to reuse the sites as future generating stations. According to Mr. Roebel, the Commission is well aware of the public concern that has accompanied some attempts to construct new generation in Indiana and elsewhere. In contrast, Mr. Roebel noted that there was virtually no local opposition to the recent Noblesville Repowering Project. These sites were selected originally because they were good sites for generation stations with access to water and to fuel supplies. He noted that there are not many good generating sites that are not already being used today and that he is not aware of any open sites that could be used for a major generation station without significant expenditures for new transmission facilities alone.

Mr. Roebel then discussed PSI's experience with regard to dismantling generating units and re-using sites. He stated the Company had completely retired one major generation station, its Dresser Generating Station, located near Terre Haute. PSI, he said, had dismantled that station and is now using the site for a machine shop. *Id.* at 3. He also noted that PSI has constructed additional generation at existing sites. PSI's Cayuga CT Peaking Unit was built at the Company's Cayuga Station site, the Wabash River Coal Gasification Repowering Project was constructed at the Wabash River Station reusing the existing Unit 1 turbine and other facilities

and most recently PSI has reused the Noblesville site and many existing facilities and infrastructures as part of the Noblesville Repowering Project.

(ii) Discussion and Findings. In evaluating the merits of this issue we are faced with various proposals from expert witnesses in response to depreciation expenses proposed by PSI. In undertaking our review of this issue, the Commission recognizes our evaluation of depreciation expenses involves the examination of many variables. The U.S. Supreme Court identified the uncertainties associated with the use of depreciation expenses in *Lindheimer v. Illinois Bell Telephone Company*, 292 U.S. 151, 168-170, 54 S.Ct. 658, 665-666 (1934), in which it stated:

If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.

Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the behavior of large groups of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.

Id.

Our determination of appropriate depreciation rates is important, as excessive depreciation rates produce excessive depreciation expense. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement that is ultimately passed on to ratepayers.

As alluded to by various witnesses in this proceeding, PSI's current depreciation rates are a result of a Settlement Agreement in Cause Nos. 39584 and 39584-S-2 (*Ind. Util. Reg. Comm'n*, February 17, 1995), the terms of which were subsequently incorporated into Cause No. 40003. While we have been presented with a wealth of testimony on this issue, we

recognize that the determination of appropriate depreciation levels is far from an exact science, and decisions on this issue must be made on a case-by-case basis.

To assist us in our evaluation of the issues, we were presented with a traditional Depreciation Study ("Depreciation Study") prepared by Mr. Spanos. A second study, in response to the Depreciation Study, was prepared by Mr. Majoros. In response to PSI's testimony, Mr. Selecky and Mr. Majoros both proposed to remove some amount of net salvage from depreciation rates and proposed to treat such costs as expenses. The most contentious issue with regard to the determination of depreciation rates and expense in this proceeding was the proper treatment of dismantling costs. Mr. Spanos testified that dismantling costs should be included in current depreciation rates. Mr. Majoros disagreed and indicated that he does not believe that PSI will dismantle its generation stations and return them to Greenfield conditions, as it has no legal obligation to do so.

In our consideration of this issue we note that PSI's estimates are not based on the cost of returning these generating station sites to Greenfield conditions. In addition, we do not find testimony, that indicated that three boilers located at operating generating stations were retired in place, controlling in our consideration as to whether these stations will be demolished at the end of their useful lives. The rebuttal testimony of Mr. Wendorf and Mr. Roebel make it clear that it is much more expensive and difficult to remove a single boiler and associated equipment while other units at a generating station are still in operation than to do so when the entire plant is demolished. This Commission is aware of the controversy that can be generated when a public utility proposes to construct a generation facility on a new site. It appears reasonable for PSI to maintain its current generation sites for future use as generating stations. Therefore, this Commission concludes dismantling costs should be included in fixing PSI's depreciation rates.

The next issue is the timing of the collection of such costs. The parties did not disagree that dismantling costs are a part of the cost of current facilities providing current service. They disagreed as to the timing of the collection of such costs and their amount. This Commission can either find that current customers should pay a share of dismantling costs, which will not be incurred for a number of years, or, in the alternative, conclude that these costs should be passed on to a future generation of customers. This Commission does not believe that the latter alternative constitutes sound regulatory policy, or is based on sound ratemaking principles. Current customers are receiving service from PSI's generation facilities. A part of the costs of those facilities is dismantlement upon retirement. Therefore, we do not believe it would be appropriate for the Company to backload the dismantlement costs for future ratepayers to pay when the facilities associated with these costs are providing service to current customers. Rather, we find it is appropriate that these costs be shared by all customers that received service from PSI's generation facilities. Accordingly, this Commission finds that dismantlement costs are properly included in determining the depreciation rates approved in this cause.

The only challenge to the estimated costs of dismantling PSI's generating stations, presented by Mr. Wendorf, was Mr. Selecky's proposal to eliminate the 25% contingency. We believe that Mr. Wendorf's testimony on this issue provides an adequate explanation as to why such a contingency is needed. Mr. Wendorf also demonstrated that minor changes in

conservative assumptions could more than use up the contingency. Therefore, based on the facts presented in this Cause, we find that Mr. Wendorf's approach is acceptable to the Commission.

The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorf's dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analyses of historical, or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, a sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.

Turning to the net salvage values for transmission, distribution and general plant, Mr. Selecky and Mr. Majoros urged this Commission to utilize historical average of actual net salvage expense incurred by PSI for determining the net salvage to be utilized for these accounts and then expense these averages as a separate cost of service item. In effect, they are proposing that net salvage values be eliminated from the depreciation rates determination in this proceeding.⁹ In contrast, Mr. Spanos took the traditional approach and utilized estimated net salvage values for these accounts based on historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or required costs to remove. Pet. Ex. II, p. 20. Mr. Majoros recognized that Mr. Spanos' approach was not abnormal, but he and Mr. Selecky cited a number of state commissions where an historical average approach had been adopted.

Based on our review of the decisions cited by Mr. Majoros and Mr. Selecky, we note that only one state commission, the Pennsylvania Public Service Commission, following the directive in a decision by the Pennsylvania Supreme Court, has implemented the historical average approach. While the Missouri and Kentucky Public Service Commissions have utilized the historical approach to net salvage values in some cases or on a trial basis, subsequent decisions have adopted the approach advocated by Mr. Spanos.

We believe that there is a sound basis for the traditional approach on this issue that is utilized by a majority of states. Utilizing historical averages as an item to be expensed to current customers means that these customers will be paying for salvage costs at levels that may not be sufficient. That means that the next generation of customers will be paying for salvage costs

⁹ Mr. Selecky proposed a 10-year average, while Mr. Majoros used a 5-year average. Mr. Majoros made the same proposal with regard to production plant.

related to facilities from which they may never have received service. The use of best estimates of future salvage costs addresses this inequity. Moreover, use of historical averages for dismantling costs does not take into account the current configuration of PSI's system with regard to its production, transmission, distribution and general facilities. Facilities in service 40-50 years ago did not take into account the significantly enhanced customer base that PSI now serves, nor the current configuration of PSI's facilities that serve these customers. It seems appropriate to utilize best cost estimates for net salvage values taking into account specific facilities now serving PSI's customers in developing depreciation rates that today's customers should pay. Accordingly, we find that the use of historical averages for net salvage values with regard to transmission, distribution and general plant for the purpose of expensing them outside the context of the depreciation determination should be, and hereby is, rejected.¹⁰

With respect to the use of the ELG or ALG methodologies to determine average service lives, we note that Mr. Selecky advocates the use of ALG to determine average service lives as opposed to Mr. Spanos' ELG methodology. This Commission on numerous occasions has accepted the use of the ELG methodology. *See, Indiana-American Water Co.*, Cause No. 40703, 1997 Ind. PUC LEXIS 429 (*Ind. Util. Reg. Comm'n*, December 11, 1997). Therefore, based on our review of the testimony we find that Mr. Spanos' use of the ELG methodology is acceptable.

Based on our review of the record on this issue, we find that the depreciation rates developed in Mr. Spanos' Depreciation Study and proposed by PSI for approval by this Commission are reasonable and appropriate and should be approved and used to determine PSI's *pro forma* operating expenses in this case. In approving PSI's proposal in this Cause, we recognize the complexity of this issue, and the fact that it will be necessary for us to carefully review this issue on a case-by-case basis in future proceedings before the Commission.

(b) Accelerated Depreciation on NO_x Equipment.

(i) Evidence. In its case-in-chief testimony, PSI requested authority to apply a 15-year depreciation rate to its NO_x compliance projects for the purpose of providing assurance of equipment cost recovery. Pet. Ex. C, p. 24. In particular, the Company would apply this accelerated depreciation rate to the same equipment approved by this Commission for use by PSI in Cause Nos. 41744, 41744-S1, 42061 and 42061-S1. Subsequently, PSI altered its request to seek authority to apply an 18-year depreciation rate to its NO_x compliance equipment. Pet. Ex. OO, p. 4.

The only party to oppose this request was Kroger. Mr. Higgins testified that PSI's request would result in a depreciation rate of 6.67% instead of the 3.52% rate derived from the depreciation study sponsored by PSI witness Spanos, and the revenue requirement related to this

¹⁰ With respect to another area of contention related to average service lives for a few accounts, Mr. Majoros proposed longer lives than those used by Mr. Spanos for six accounts. We find Mr. Spanos' testimony provides an adequate explanation on this issue and we decline to substitute the calculations of Mr. Majoros for only those few accounts.

difference was \$10.5 million. Mr. Higgins testified that he believed that this request should be denied as it would compound the cost burden to customers at a time when the Company was seeking a 15% rate increase. Kroger Ex. No. 1, p. 21.

(ii) Discussion and Findings. We find PSI's request to be in accordance with the law and reasonable. IC 8-1-2-6.7(b) permits PSI to seek Commission approval of a 10-year depreciation rate for equipment deemed to be clean coal technology. We believe PSI's proposal is reasonable, will ensure cost recovery of Commission approved projects to which PSI is statutorily entitled, and should be approved. Therefore, we find that PSI should be authorized to utilize an 18-year life over which to depreciate its Commission-approved NO_x equipment. We note that our decision here is entirely consistent with our November 25, 2003 Order in Cause No. 42411.

(2) Purchased Power. In opposing PSI's proposed Summer Reliability Tracker, the OUCC contended that PSI's 2003 level of purchased power expense should be included in base rates. In response, Mr. Esamann indicated that the inclusion of the OUCC's proposed level of purchased power expense in PSI's base rates would require the Commission to use an abnormally low level for the expense, given that the Company's 2003 purchased power costs were by far the lowest level of forward reliability purchased power costs experienced by PSI since prior to 1999 (less than \$2 million). Pet. Ex. DD, pp. 18-19. He said, this low level of purchased power expense is likely to be temporary, given the expected gradual increase in wholesale power prices and the approximately 100 MW of annual demand growth PSI is experiencing on its retail system. *Id.* at 19. Accordingly, Mr. Esamann said, if the Commission were to include a base amount in PSI's rates, he would recommend the use of an average of the last two years' forward reliability purchased power costs, which amounts to \$10.5 million. *Id.* That level, he said, is still lower than PSI's estimated annual purchased power costs over the next few years. *Id.*

Consistent with our discussion of the issue below, we find that PSI's purchased power costs are variable and therefore appropriate for tracking treatment. Accordingly, we decline to include an amount of purchased power costs in base rates. The details of our finding on this issue are set forth below.

(3) PowerShare® PowerShare® is a peak load managing program that provides PSI's commercial and industrial customers with two options, CallOption and QuoteOption. Under CallOption, the customer contractually commits to reduce its load under certain prescribed circumstances in exchange for a premium. In addition, at times of system peak when the customer is called on to reduce its load, and the customer complies, the customer receives an energy credit. The QuoteOption program is similar, except that the customer is not required to reduce its load when called upon. Pet. Ex. AA, pp. 11-12. Therefore, QuoteOption customers receive only the energy credits if they are called to reduce load and they comply. *Id.*

PSI proposed that the test period level of PowerShare® expense should be included in base rates, in an amount of approximately \$1 million. No party objected to the base level amount of PowerShare® expense. PSI also proposed that PowerShare® costs be tracked as part

of the Summer Reliability Tracker, so that only actual PowerShare® costs are collected from ratepayers. While we discuss the entirety of the Summer Reliability Tracker below, we find that that PSI's base rate amount of \$1,023,000 million of test year expense is reasonable and should be approved as an appropriate level of PowerShare® expense.

(4) Service Company Allocations.

(a) Evidence. PSI witness Barry F. Blackwell, Director of Cost Accounting and External Reporting for Cinergy Services, Inc., (the "Service Company") provided testimony regarding the processes used to assign costs between PSI and its affiliate companies, pursuant to various service agreements which PSI has entered into with those affiliates. Pet. Ex. L, p. 2. Mr. Blackwell testified that the Service Company updates the cost allocation ratios it uses in allocating costs to its client companies by performing a cost study at least annually, taking into consideration specific changes that are fixed, known and measurable. *Id.* at 10-12. Mr. Blackwell cited as an example of such a change the Financial Accounting Standards Board's ("FASB") Emerging Issues Task Force ("EITF") Issue 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities ("EITF 02-3"), which requires that all revenues and expenses on energy trading derivatives be presented on a net basis beginning January 1, 2003. *Id.* at 12-13.

Mr. Blackwell stated that this change will result in substantial reductions in reported operating revenues, purchased and exchanged power expenses and gas purchased expenses. *Id.* Mr. Blackwell explained that prior to this accounting change, these revenues and expenses were recorded on a gross basis, with no offset of energy trading revenues against energy trading costs. *Id.* In Mr. Blackwell's opinion the accounting changes mandated by EITF 02-3 comport with cost causation principles, because costs will be allocated to Cinergy's trading operations in a manner more closely aligned with the services that they receive from the Service Company. *Id.* at 13-14.

OUCG witness Carver testified in opposition to PSI's adjustment related to changes in the allocation ratios, citing three issues with the allocation methods used by the Service Company: 1) use of net versus gross revenues in determining allocation factors; 2) the Service Company's derivation of the peak demand allocator; and 3) consideration of newly acquired and sold properties. Mr. Carver recommended that PSI back out \$3.045 million in *pro forma* adjustment to test year operating expenses related to costs allocated to PSI by the Service Company. Pub. Rev. Ex. No. 3, Sch. C-17.

With respect to Mr. Carver's first issue, the net versus gross revenue issue, Mr. Carver believes that PSI's reliance on EITF 02-3 in developing its proposed allocation factors inconsistently applies net versus gross revenue recognition in developing revenue-related allocation factors. Mr. Carver asserts that when net revenue is used to derive allocation factors for trading operations, the same approach should be used in deriving allocation factors for non-trading operations. Mr. Carver argued that the approach of using net revenues for trading operations but gross revenues for regulated operations means that a disproportionate share of costs are allocated to regulated operations. Pub. Ex. No. 1, p. 96.

With respect to Mr. Carver's second issue, the derivation of the peak demand allocation factor, Mr. Carver testified that PSI erred when it adjusted this allocation factor to add the capacity of the Madison and Henry County generating units to PSI's actual system peak demands. *Id.* at 97. Mr. Carver stated that this adjustment is contrary to the Utility Service Agreement, which states that the electric peak load ratio should reflect the domestic firm electric maximum system demands for the immediately preceding 12 calendar months. According to Mr. Carver, the Utility Service Agreement requires the allocation to be based on demand, not capacity or supply levels. *Id.* at 98.

Turning to Mr. Carver's third issue, the full year effect of properties newly acquired or sold during 2002 and 2003, Mr. Carver cited, as one example, a discontinued operation that had been removed from the development of allocation factors as its operations were winding down in 2002 and was expected to have little or no activity in 2003. *Id.* at 99-100. In contrast, he cited a newly acquired property that began operations in 2002, but the allocation study only included three months of revenue for this property. *Id.* The effect of this inconsistency, according to Mr. Carver, is that more costs are allocated to regulated operations than appropriate. *Id.* Mr. Carver argued that these types of transactions should be fully and consistently recognized on a forward-looking basis. *Id.* Mr. Carver concluded that PSI should perform a new allocation study, with updated numbers consistent with the fixed, known and measurable provisions of the Prehearing Conference Order so that, in his view, more appropriate allocation factors could be developed. *Id.*

Testifying in rebuttal, Mr. Blackwell addressed the three issues raised by Mr. Carver. Pet. Ex. NN, p. 1. Mr. Blackwell criticized Mr. Carver's proposal to use revenues from non-trading operations net of fuel and purchased power costs to derive revenue-based allocators. *Id.* at 2-5. He noted that many of Cinergy's companies do not have fuel purchases and purchased power costs. Thus, Mr. Blackwell pointed out, utilizing Mr. Carver's methodology of using revenues, net of fuel and purchased power costs, would result in just the sort of mixing of net and gross revenues that Mr. Carver claimed to be seeking to avoid. *Id.* That is, Mr. Carver is recommending that the Service Company use gross revenues for affiliated companies that do not have fuel and purchased power costs and net revenues for those that do. *Id.*

Mr. Blackwell observed that fuel and purchased power costs should be treated differently in non-trading operations than they are in trading operations, because fuel and purchased power are real costs of power furnished to end-use customers. *Id.* Mr. Blackwell explained that fuel and purchased power costs represent real costs of goods sold in a traditional sense when incurred in serving end-use customers, while on the other hand, financial trading transactions are simply financial transactions, with no physical goods flowing from one party to another. *Id.* at 3. Mr. Blackwell testified that EITF 02-3 recognized this distinction by requiring all physical trading activity be presented on a gross revenue basis and financial trading activity to be presented on a net revenue basis. *Id.* at 2-5. Moreover, as explained by Mr. Blackwell, the same issue arises in the cost allocation process, where gross revenues from trading operations do not accurately convey the extent of services being provided to these trading operations. *Id.* Mr. Blackwell produced a chart (Pet. Ex. NN-1) illustrating a trend in which a decreasing level of costs are

allocated to the Service Company's utility company affiliates, including PSI, during a time in which PSI's business, and presumably the amount of services it utilizes from the Service Company, has not changed to a significant degree. Pet. Ex. NN, p. 7.

Regarding Mr. Carver's issue with the derivation of the peak demand allocator, Mr. Blackwell conceded that the Service Company had deviated from the allocation methodology set forth in the Utility Service Agreement. Accordingly, Mr. Blackwell stated, the Service Company revised its system peak demand allocation ratios to conform to the requirements of the Utility Service Agreement. PSI adjusted its earlier *pro forma* to reflect this change. Pet. Ex. NN, p. 7; Pet. Ex. PP, p. 3.

With respect to Mr. Carver's third issue with the Service Company's cost assignment practices, that of the consideration given to newly acquired and/or sold properties, Mr. Blackwell disagreed with Mr. Carver. *Id.* at 7. Mr. Blackwell explained that, in accordance with the Utility Service Agreement, the Service Company performs an annual cost allocation study, based on historical data gathered during the third quarter. *Id.* at 7 – 8. He said that when the Service Company knows of companies that are winding down their operations and will no longer be taking services from the Service Company, it excludes from its calculations of the allocation factors the data associated with these companies. *Id.* Mr. Blackwell testified that when an acquisition of a company occurs outside the annual study timeline, the Service Company determines the effect of the acquisition and updates the appropriate allocation factors where such effect is expected to be material. *Id.* He testified that the Service Company reviewed all revenue/sales based allocation factors, picking up twelve months of data for various entities sold/purchased/discontinued in 2002 and 2003, as requested by Mr. Carver, and determined that the amount of costs allocated to PSI based on these allocation factors would have been merely \$90,000 less, which in Mr. Blackwell's opinion is not material in PSI's case. *Id.* at 9 – 10.

(b) Discussion and Findings. Other than the three issues identified by the OUCC, there were no issues raised with respect to the assignment of costs between PSI and its affiliates. Regarding the first issue raised by OUCC, the derivation of revenue-based cost allocation factors on net revenue versus gross revenue basis, this Commission finds that the methodology proposed by PSI is reasonable. The evidence supports PSI's proposition that there is a sound basis for distinguishing between revenues generated from trading operations and revenues generated from other types of operations. The FASB has required that financial trading transactions should be accounted for on a net revenue basis, whereas physical trading transactions should continue to be accounted for on a gross revenue basis. Although Mr. Carver argues that consistency requires that net costs be used for both, PSI's testimony demonstrated that Mr. Carver's approach, while resolving one set of inconsistencies, introduces another set of inconsistencies. This Commission is aware of the possible concern of the financial community regarding measuring financial trading operations based on gross revenues, and agrees that deriving allocation factors based on these gross revenues can distort the apparent extent of trading operations and the amount of services they may take from the Service Company. Ultimately, whether or not an allocation methodology allocates more costs to utility affiliates, as opposed to non-utility affiliates, is not the issue. The determination that must be made is

whether the costs incurred by the Service Company are allocated properly to those affiliates that cause the costs to be incurred.

With respect to Mr. Carver's second issue, the derivation of the peak demand allocation factor, Mr. Blackwell conceded that Mr. Carver correctly determined that PSI erred when it adjusted this allocation factor to add the capacity of PSI's new generating units (Madison and Henry County) to PSI's actual system peak demands, in a manner contrary to the Utility Service Agreement. Mr. Blackwell indicated that he revised the system peak demand allocation ratios to conform to the requirements of the Utility Service Agreement. Therefore, as Mr. Blackwell corrected this error there is no pending dispute between the parties on this issue.

With respect to Mr. Carver's conclusion that a complete updated cost allocation study, based on the acquisition or dissolution of properties is needed, we find that while Mr. Carver raises legitimate concerns on certain aspects of this issue, based on the totality of the evidence presented in this Cause we question the overall cost/benefit of doing such a study. Based on our review of the evidence presented, it is apparent that PSI reviewed all revenue/sales based allocation factors, picking up twelve months of data for various entities sold/purchased/discontinued in 2002 and 2003, and determined that the amount of costs allocated to PSI would have been merely \$90,000 less. There is no indication in the record that a complete updated study would yield a materially different result than that used by PSI here. Furthermore, at the Evidentiary Hearing in this Cause, Mr. Howe observed that in order to include all changes in test year operating expenses related to changes in allocation factors which were fixed, known, and measurable by September 30, 2003 (12 months after the test period), as allowed by the Prehearing Conference Order, PSI could not begin the required cost allocation study until October 1, 2003, when the latest data through September 30, 2003 would have become available. Since such a study takes several months to complete, it clearly could not have been completed by the date of PSI's rebuttal prefilings, or even the date of the evidentiary hearing. Tr. at Y30 – Y31.

In any event, the issue before this Commission is whether the cost allocation methodology utilized by the Service Company is representative of future costs to be properly allocated to PSI, when the rates determined in this proceeding will be effective. Other than the three issues raised by OUCC, there were no issues raised with regard to the assignment of costs between PSI and its affiliate companies. We find that the costs assigned to PSI represented in this proceeding are just and reasonable and should be fully recoverable by PSI.

(5) Sale of Accounts Receivable/Forfeited Discounts/Uncollectible Expense.

(a) Evidence. In February 2002, Cinergy replaced an existing accounts receivable sales agreement with a newly structured receivables sales facility that has a maximum funding capacity of \$400 million. Under this Agreement, PSI, along with Cinergy's other utility operating companies, sells its accounts receivable to an affiliate, Cinergy Receivables Company, LLC ("Cinergy Receivables"). The receivables purchased by Cinergy Receivables are then used as collateral for Cinergy Receivables to secure non-recourse loans from third party lenders. The purpose of these loans is to enable Cinergy Receivables to purchase the accounts receivable. PSI sells its accounts receivables in order to receive upfront cash, rather than waiting until the

accounts receivables are collected. This cash helps the Company preserve its various bank lines of credit to meet other short-term financing needs. Pet. Ex. QQ, p. 8.

Summarizing the Company's own adjustment in computing *pro forma* operating income under current rates, Mr. Farmer said that the Company eliminated all test period expenses related to the sale of accounts receivable other than uncollectible accounts expense totaling \$5.7 million. *Id.* at 13. Uncollectible accounts expense was not eliminated, he said, because the Company recognized that a portion of *pro forma* revenues included in this case would not be realized, because they would be uncollectible. PSI developed a factor, based on a four-year average relationship of uncollectible accounts expense to revenues that was applied to *pro forma* test period revenues. The effect of PSI's adjustment was to adjust test period uncollectible accounts expense for changes in revenue levels in addition to the elimination of all costs not directly related to non-payment by customers.

OUCC witness Carver sponsored OUCC Adjustment C-5, which increased PSI's test period revenues by \$5,419,000, the test year's level of forfeited discount revenues, which PSI had proposed to exclude. Pub. Ex. No. 1, p. 17. Forfeited discounts and late payment fees are merely different names for the same revenue (*i.e.*, customer charges due to late bill payment). Mr. Carver stated that it was his view that the ratepayers should be no worse off as a result of PSI selling its accounts receivable than would be the case if the account receivable sale had never occurred. *Id.* at 21. Mr. Carver testified that if the effect of the sale is a good deal for the regulatory participants, it would be reasonable to expect the arrangements to positively improve the utility's operating income and cash flow, and ratepayers should reasonably expect to participate in these benefits. However, in Mr. Carver's view, the net impact of the Company's arrangement to finance its receivables with an affiliate was detrimental to the ratepayers.

Mr. Carver conceded that it is certainly possible that the receivable sales agreement could accelerate PSI's cash realization to the point that this annual cost could be reasonable. However, the only way, he said, to determine the benefit of cash flow acceleration is through a lead-lag study, which PSI has not done. *Id.* at 24-25. Instead, he said, PSI's rate base calculation assumes that "zero" is a reasonable approximation of PSI's cash working capital requirement that would result from a detailed lead/lag study. In Mr. Carver's opinion, such an assumption is inappropriate because a properly conducted lead/lag study could result in a negative cash working capital requirement. Mr. Carver indicated that a zero cash working capital assumption is inappropriate where ratepayers are asked to bear the additional costs of the "zero" cash working capital requirement assumption, but receive no benefit from the receivable sales agreement.

Mr. Carver calculated that Cinergy Receivables realized net income of about \$4.4 million in 2002, before income taxes. He stated that OUCC Schedule A-1 recognizes both forfeited discount and uncollectibles in the development of the revenue conversion factor, while the Company recognized only the uncollectibles. He added that if the Commission concludes that the forfeited discount should be removed from test year revenues and excluded from the revenue conversion factor calculation, then the Commission should also revise PSI's tariff to remove all provisions for charging late payment fees to its customers.

Mr. Farmer testified in rebuttal to Mr. Carver's adjustment. He stated it would not be proper to credit the cost of service with forfeited discount revenues, because under the Cinergy Accounts Receivable Purchase and Sales Agreement, PSI does not retain the right to keep revenues received from customers due to late payments. Rather, he observed, PSI has transferred that right to the purchaser of the receivables. However, he pointed out, PSI's customers *have* received significant benefits from the sale of accounts receivable in the form of cost savings. Pet. Ex. QQ, p. 7. Mr. Farmer explained that by selling accounts receivable the Company is able to accelerate the recovery/realization of billed revenues by converting receivables (a non-earning asset) immediately into cash. He stated that if PSI did not sell these receivables, it would incur costs to finance the lag between the time when revenues are billed and payment is received from customers. Accordingly, without the accounts receivable sales agreement, PSI would incur a permanent financing requirement that would likely be met by issuing commercial paper, borrowing against credit lines, or reflecting increased equity and/or debt borrowing in PSI's capital structure. By selling the accounts receivable, PSI is able to eliminate this payment lag. PSI and its customers will benefit to the extent that the fee charged by the purchaser of the receivables is less than the cost that would have been incurred if the Company were to finance the receivable itself. *Id.* at p. 8-10.

Mr. Farmer gave examples of ways in which PSI customers have benefited from such accounts receivable sales. *Id.* One example was the Company's use of the proceeds from its initial sales of account receivables to retire/redeem preferred stock and first mortgage bonds, as part of the financial restructuring that took place in the late 1980's. In addition, the Company used some of the cash to finance capital investments. However, Mr. Farmer pointed out that the primary benefit of selling accounts receivable is to utilize the cash received from such sales to meet ongoing working capital needs. If a utility has working capital needs due to the lag in the cash realization of billed revenues relative to the payment of operating costs incurred by the Company, that capital need is generally recognized in the setting of rates by including a cash working capital allowance in the rate base. However, because of its accounts receivable sales, Mr. Farmer stated, the Company has not requested, and is not requesting, that a cash working capital allowance be reflected in the rates approved in this case. *Id.* at 8-10.

Mr. Farmer noted that in order for Mr. Carver's contention that customers have not benefited from the sale of accounts receivable to be accurate, the Company's cash working capital needs must be negative. This statement, according to Mr. Farmer, is incorrect because PSI's accounts receivable balance (an indicator of potential cash working capital needs) is approximately \$175 million. At the hearing on PSI's rebuttal testimony, Mr. Farmer was questioned about the level of profit earned by Cinergy Receivables as a result of its sale of accounts receivable agreement with PSI. Mr. Farmer indicated that approximately 40% of the \$4.4 million (*i.e.*, \$1.76 million) of profits in 2002 was attributable to the purchase of PSI's accounts receivable Tr. at Y123-Y124. The remainder of the \$4.4 million is attributable to the purchase of accounts receivable from CG&E.

Mr. Farmer pointed out that Mr. Carver agrees that PSI, under its arrangement with Cinergy Receivables, has transferred, and, therefore, does not own the rights to forfeited

revenues. At the same time, Mr. Carver observed, PSI also no longer incurs costs associated with late payment by its customers. Mr. Farmer stated that if one were to accept Mr. Carver's adjustment, the cost of service used to set rates in this proceeding would be credited with revenues that PSI does not retain. Mr. Farmer disagreed with Mr. Carver's position that if the Commission accepts PSI's adjustment, it should revise PSI's tariff to remove all provisions for charging late payments to its customers. Pet. Ex. QQ, p. 15. Mr. Farmer stated that there is a cost when a customer makes a payment late that is not changed, regardless of which party is bearing that cost. In this case, PSI has passed the risk of late payment to the purchaser of its accounts receivable, and it is appropriate that the purchaser receive the late payment revenues.

(b) Discussion and Findings. The effect of Mr. Carver's adjustment is to credit PSI's revenues with \$5.4 million that is not in fact retained by the Company. Based on our review of the record it appears that PSI will not realize its account receivable revenues, because they have been sold to an affiliated entity. Mr. Carver does not dispute the terms and conditions under which the account receivables are being sold to Cinergy Receivables. Nor does Mr. Carver disagree that if the deal is a good one for PSI, then customers will share in the benefits. Mr. Farmer testified that historically PSI customers *have* benefited from the Company's sale of account receivables, as PSI has used the revenues from previous sales to refinance preferred stock and long-term debt and finance construction investments.

In the current proceeding, Mr. Farmer made it clear that selling the account receivables has enabled the Company not to request working capital as a component of its rate request, even though PSI's account receivables total \$175 million. This level of receivables is a strong indication that PSI would not have a negative working capital allowance as suggested by Mr. Carver, even if we recognized a negative cash working capital requirement, which we do not. We find that there is a cash working capital benefit to PSI and customers that results from PSI's sale of accounts receivable, albeit one that is not quantified. Accordingly, we do not accept Mr. Carver's recommendation that PSI be credited with \$5.4 million in revenues. At most, the record reflects that a \$1.76 million credit to revenues might be justified to reflect the level of annual profit earned by Cinergy Receivables by virtue of its agreement with PSI. However, even that amount of credit fails to recognize that PSI does not retain those revenues, and for this reason we will decline to make any adjustment to PSI's proposed *pro forma* revenues. We also decline to revise PSI's tariff to remove all late payment charges, as there is a cost associated with the late payment of bills, and this cost should be recovered from the late payees to address these costs.

(6) Production O&M Expenses.

(a) Evidence. OUCC witness Brosch proposed two adjustments with regard to PSI's production O&M expenses. OUCC Adjustment C-7 reduced production, non-fuel O&M expenses related to PSI's Madison, Henry County, Edwardsport and Noblesville production facilities. Mr. Brosch claimed that the costs included by PSI for the Madison and Henry County stations are based upon budget values that are not fixed, known and measurable and in his opinion, overstate the expenses related to actual cost levels experienced at those stations. He stated that his Adjustment C-7 reflects the adjustments that are needed to restate the Madison and

Henry County related O&M increases, based upon actual 2002 expense levels, in lieu of the Company's budgeted values.

OUCC Adjustment C-8 was made, according to Mr. Brosch, to correct and restate amounts within PSI's adjustment for NO_x expenses sponsored by Mr. Farmer. Pub. Ex. No. 2, p. 90. According to Mr. Brosch, the Company's proposed adjustment is predicated entirely upon budgeted costs for ammonia and contractors' services anticipated to be incurred due to the addition of the SCR equipment at Gibson Units 2, 3 and 4. The OUCC's Adjustment C-8, he said, substitutes actual SCR O&M cost information for the estimates utilized by the Company. Mr. Brosch stated that the largest differences between the Company's adjustments and OUCC's Adjustment C-8 relates to the difference in ammonia costs. Mr. Brosch concluded that an allowance for ammonia of \$141,000 for each of the Gibson SCR units is appropriate.

Mr. Farmer presented rebuttal testimony in response to the OUCC's Adjustments C-7 and C-8. Mr. Farmer noted that, as a practical matter, a utility must estimate annual costs of new projects which have not been in-service during all 12 months of the test year. Pet. Ex. QQ, pp. 16-18. With regard to Adjustment C-7, Mr. Farmer stated that Mr. Brosch had made a mathematical error and had double counted a \$380,000 reduction. After correcting for this error, Mr. Farmer determined that the difference between the O&M expenses related to this issue as presented by PSI were only 17% greater than the actual 2002 expenses, recommended by Mr. Brosch. Pet. Ex. QQ, pp. 16-18. In order to test the reasonableness of PSI's estimates for purposes of reflecting an ongoing level of production O&M, Mr. Farmer compared PSI's estimates to the actual, non-labor O&M incurred for the 12 months ended August 31, 2003 at the Madison and Henry County facilities. This comparison showed a difference of only 9%. Given this small difference, Mr. Farmer concluded that the Company's *pro forma* cost level was reasonably representative of an ongoing cost level. In Revised Schedule C-7, Mr. Brosch corrected the double counting error, but still proposed lower O&M costs for the Madison and Henry County Stations.

With respect to the OUCC's Adjustment C-8, Mr. Farmer confirmed that the NO_x O&M costs included in the case are primarily driven by costs incurred to operate the Gibson SCRs. The SCRs were operated in 2002 and are being operated in 2003 in order to generate early reduction NO_x credits. *Id.* at 18-20. He noted that Gibson Units 2 and 3 SCRs were declared commercial in July, 2002 and that the Gibson Unit 4 SCR was declared commercial in July, 2003. He stated the in-service dates are significant to the issue of determining annual O&M costs, because in both 2002 and 2003 the SCRs were declared commercial two months into the NO_x compliance season of May-September. Accordingly, because the SCRs were in service during only a portion of the NO_x compliance season and not the normal five months, the 2002 data used by Mr. Brosch to make his adjustment is not representative of normal ongoing cost levels.

Mr. Farmer testified that SCR operating expenses are primarily driven by the costs of ammonia and that Mr. Brosch's ammonia costs are predicated on information provided by PSI in response to OUCC Discovery Request 23-565. At the time the responses were provided, the latest available month was May, 2003, and the Company's response set forth an *average* price

paid in 2002 up to that time of \$170.09 per ton. However, that same data response stated that the price paid in May was \$322.70 per ton, an increase of 90% when compared to the average 2002 price. Mr. Brosch did not take into account, Mr. Farmer pointed out, the higher prices for ammonia in 2003, compared with 2002, which were set forth in the data response.

To test the reasonableness of Mr. Brosch's ammonia costs and PSI's projected ammonia costs utilized in its adjustment, Mr. Farmer looked at current information based on actual deliveries and costs of the ammonia used at the Gibson Station. The Company's invoiced cost of ammonia purchased for 2003 was \$1,107,659, excluding the cost of one tanker load, which remained outstanding at that time. Pet. Ex. QQ, p. 20. Given the fact that the Gibson Unit 4 SCR ran for only a part of the season, Mr. Farmer concluded that the Company's \$1,141,000 initial estimate of annual ammonia expense for a normal five-month compliance period at today's prices is reasonable and more representative of ongoing cost levels. In contrast, Mr. Farmer noted that Mr. Brosch's allowance for annual ammonia expense of \$423,000 would grossly understate the costs being incurred by PSI in operating its Gibson Units. In Revised Schedule C-8, Mr. Brosch revised his *pro forma* adjustment to accept PSI's proposed ammonia costs. However, Mr. Brosch maintained his lower O&M Material, and Contractor Labor amounts.

(b) Discussion and Findings. We find that PSI's estimates of the subject costs are reasonable. In making OUCC Adjustment C-7, regarding PSI's production non-fuel O&M expenses, Mr. Brosch utilized actual 2002 data in an effort to demonstrate that PSI's adjustment was overstated. Mr. Farmer utilized more recent data in an effort to show that Mr. Brosch's adjustment was understated. The difference between the actual twelve months ended August 31, 2003, and PSI's original *pro forma* adjustment amount was only 9%. Given the apparent variability in non-labor O&M costs, as evidenced by the fact that the twelve months ended August 31, 2003 for the Henry County Plant was \$158,000 less than the actual 2002 costs, this Commission finds that PSI's estimate represents a reasonable approximation of an ongoing level of production, non-fuel O&M expenses and it should be approved.

The lack of a full test year of operating data also was present in determining the ongoing level of production O&M expenses related to the operation of the Gibson SCR units. Mr. Farmer explained that the SCRs were not declared commercial until July 2002 and July 2003, and the normal NO_x compliance five-month season is May 1 through October 1. Thus, actual O&M expense for 2002 data used by Mr. Brosch was understated. Mr. Farmer, again utilizing more recent data than Mr. Brosch, testified that it could cost PSI \$1,316,700 for the cost of ammonia, alone, to operate these SCR units using actual 2003 ammonia prices. PSI had proposed a total annual production O&M expense for NO_x equipment of \$1,333,000. With Mr. Brosch's acceptance of PSI's proposed ammonia expense, the difference between PSI's proposed adjustment and the OUCC's proposed adjustment is only \$170,000. Because PSI used more recent data, we find that Mr. Farmer's estimate of production O&M costs for operating the Company's SCR facilities is not unreasonable.

(7) Software Amortization Costs.

(a) Evidence. OUCC witness Carver sponsored OUCC Adjustment C-12, which reduced PSI's amortization expense by \$1,257,489. Mr. Carver explained that this adjustment recognized the August, 2003 termination of certain software investment amortizations. Pub. Ex. No. 1, p. 33. He stated that in general the Company records its software investment as Intangible Plant and then amortizes the investment over its anticipated useful life, normally five or ten years. Mr. Carver noted that PSI's July 31, 2003 update filing removed amortizations that expired by May 31, 2003. Mr. Carver opined that his adjustment to remove all amortizations that will expire by September 30, 2003, was in accord with the Prehearing Conference Order, which allowed for fixed, known and measurable adjustments through the twelve months following the end of the test year.

On rebuttal Mr. Farmer pointed out that he believed that Mr. Carver was applying inconsistent standards in making his adjustments to Intangible Plant and Tangible Plant. For purposes of depreciation expense, Mr. Farmer noted, Mr. Carver had utilized plant balances as of May 31, 2003, which Mr. Farmer observed was consistent with his reading of the Prehearing Conference Order. Pet. Ex. QQ, pp. 29-31. Mr. Farmer testified that, at a minimum, intangible and tangible plant should be treated alike. If PSI's depreciable plant were updated to August 31, 2003, PSI's investment in depreciable plant, excluding plant subject to amortization, would increase by \$25,675,000 and amortizable plant would decrease by \$6,598,000. He also stated that if the depreciable plant were so updated to September 30, 2003, as Mr. Carver updated plant subject to amortization, the increase in PSI's depreciation expense may be even higher, due to additional depreciable plant investment. *Id.* at 31-32. Mr. Farmer stated that the cut-off date should be the same for items as interrelated as depreciation and amortization expense associated with PSI's rate base.

(b) Discussion and Findings. Based on our review of the testimony it appears that Mr. Carver applied inconsistent standards to plant subject to depreciation and plant subject to amortization. For the former, he used plant balances as of May 31, 2003. For the latter, he used plant balances at September 30, 2003. This resulted in the update of an expense that was decreasing, without a corresponding update to an almost identical expense that was increasing. We find that adjustments to test year results of the same basic cost items should be done in a consistent manner. Therefore, in this case we agree with Mr. Farmer that it makes sense to use the general rate base cut-off date of May 31, 2003 which was agreed to by all parties, and to also update depreciation and amortization expense which constitute a *return of* that same rate base amount.

(8) Public Safety Advertising.

(a) Evidence. PSI proposed an adjustment to test year expenses in the amount of \$619,000 related to the Company's public safety advertising program. Pet. Ex. Y-18. In support of that adjustment, PSI witness Leigh J. Pefley testified that, beginning in 2003, PSI significantly stepped up its public safety advertising. Pet. Ex. J, p. 10. She stated that through periodic radio advertising, PSI intends to build public awareness of where power lines are

located and the need to stay clear of them. She said that the initial phase of the campaign consisted of a nine-week schedule, beginning in March, of radio advertisements in the major markets of Indianapolis, Terre Haute and Lafayette as well as over 27 non-major markets. The second phase of the project will consist of ten weeks of radio advertising during the months of June through November. She stated that PSI plans to continue its public safety awareness advertising on an annual basis. Ms. Pefley was of the opinion that it was important to convey to PSI's customers how to be safe around electricity and that the Company's program accomplished that goal.

OUCC witness Carver stated that while the OUCC encourages public utilities to conduct public safety awareness campaigns, in his opinion, there were too many uncertainties surrounding the annually recurring magnitude of PSI's campaign, implemented in 2003, to fully justify the adjustment. Pub. Ex. No. 1 p. 64. He testified that PSI did not provide any studies or quantitative analyses to support the decision to implement the new safety advertising program. *Id.* at p. 64. Instead, the Company appears to have decided to increase its public safety advertising based on recent incidents involving public contact with electrical facilities, where the victims may not have been aware of the existence of electrical facilities or the dangers posed by electricity—however, specific information regarding incidents of this nature had not been provided by PSI. *Id.*, at 64-67. Mr. Carver added that PSI also had expended less than \$10,000 in public safety advertising during the six-year period ending with calendar year 2002. He stated that PSI's affiliates similarly expended little on public safety advertising, even though significant levels of advertising expense appear to have been included in PSI's last Indiana retail rate case. *Id.* at 68-71. Given this history, Mr. Carver was concerned that, absent assurance otherwise, PSI's safety advertising expenditures could again be reduced following this rate case. *Id.*, at 72-73. Mr. Carver proposed that if PSI is allowed to recover some level of safety advertising expense in retail rates, the Company's adjustment should either be reduced by 50%, or PSI should be required to make an annual filing with the Commission, with copies to the OUCC, explaining any reduction in public safety advertising expense greater than 10% of the allowed amount.

Mr. Esamann submitted rebuttal testimony in response to Mr. Carver's testimony. He described the Company's 2003 campaign and said that by the end of August, 2003, PSI had incurred actual expenditures of \$408,000. Pet. Ex. DD, pp. 40-41. Mr. Esamann also gave assurance that PSI is committed to a multi-year public safety campaign. He said that PSI has already undertaken steps to develop a media schedule for 2004, with the creation of at least two additional media spots for 2004. Mr. Esamann stated that these costs were prudently incurred and should be fully reflected in the ratemaking process. He also said that PSI would have no objection to filing an annual report as suggested by Mr. Carver. *Id.* at 42.

(b) Discussion and Findings. Based on the evidence presented on this issue, we find that PSI should be allowed to recover some level of public safety advertising expense and that it should not be necessary for PSI to report to the Commission regarding the ongoing level of these expenditures. Through its testimony, PSI demonstrated the importance of undertaking an ongoing public safety advertising campaign and we believe that PSI should, and will, utilize the full amount allocated by the Commission for this purpose.

Mr. Carver does not contest the level of the \$619,000 expense or the actual expenditures made by PSI in 2003, but believes that the Company did not fully demonstrate the need for the recurring level of such costs. While Mr. Esamann's rebuttal testimony provides some assurance that PSI plans to continue its public safety advertising program in the future, our review of the historic level of these expenditures indicates that even if the amount requested by PSI is reduced as Mr. Carver proposed, it would still represent a dramatic increase in expenditures for this purpose. Therefore, we agree with the OUCC that a 50% reduction in the amount proposed by PSI is warranted and find that PSI should be allowed to recover \$310,000 of program costs. We also find that the Company should not be required to submit annual reports regarding its expenditures on public safety advertising campaigns.

(9) Salaries, Wages, Benefits, and Incentive Compensation.

(a) Evidence. PSI proposed a *pro forma* adjustment which reflected an annualized level of salaries, wages, and benefits at the May 31, 2003 cut-off date. In the end, there was no challenge to PSI's proposed adjustments. Tr. at P50. We find that PSI's proposed salaries, wages and benefits should be approved. In addition, PSI also seeks recovery of \$12,883,000 in incentive pay expense. Pet. Ex. PP-8, Sch. C-3.17, p. 2. Mr. Verhagen testified in support of PSI's level of incentive. He stated that PSI began using incentive pay in 1987 and described the Company's major incentive pay programs: (1) the Cinergy Corp. Annual Incentive Plan ("AIP"); (2) the Energy Merchant Business Unit Annual Incentive Plan ("EMBU AIP"); (3) the Cinergy Corp. Non-Union Employee Incentive Plan ("NEIP"); (4) the Cinergy Corp. Union Employee Incentive Plan ("UEIP"); and (5) the Cinergy Corp. 1996 Long-Term Incentive Compensation Plan ("LTIP"). Pet. Ex. R, p. 10.

According to Mr. Verhagen, the AIP is a short-term incentive plan that allows employees to receive cash payments as certain performance goals are attained during the preceding calendar year. The AIP is available to selected exempt employees of PSI and Cinergy Services. The purpose of the AIP is to attract, retain and motivate employees, enhance teamwork and high levels of achievement and to facilitate the accomplishment of specific corporate business units and individual goals. Employees are selected to participate in the AIP. Mr. Verhagen stated that the compensation committee of the Cinergy Corp. Board of Directors monitors on an ongoing basis the AIP performance goals and the level of compensation paid through the AIP. Performance goals are the objective that the relevant business unit and individual employees must attain in order for the employees to receive payment under the AIP. Mr. Verhagen stated that for the Regulated Business Unit ("RBU") employees participating in the AIP, the individual goals and the employee's business unit goals were weighted equally. *Id.* at 11-12. In 2002, the business unit goals of the RBU were based on the following factors: (1) electric SAIDI; (2) electric CAIDI; (3) gas CAIDI; (4) lost time accident rate; (5) number of traffic accidents; (6) customer satisfaction score results; (7) O&M expense levels; and (8) capital expenditure level. *Id.*

The EMBU AIP, according to Mr. Verhagen, is another short-term incentive plan that provides cash payments to employees if certain performance goals are met. Like the AIP, the

EMBU AIP is available to selected employees, but these employees do not participate in the AIP. The performance goals for the EMBU AIP consist of a corporate earnings component and EMBU earnings component. Performance goals are related to the business segment of the EMBU to which the employees are assigned individual performance goals. Mr. Verhagen noted that PSI's rates reflect labor expense from Cinergy Services and Cinergy Power Generation Services employees who allocate time to PSI and who participate in the EMBU AIP because they work at PSI's generating stations, provide generation support and provide back office support. The EMBU AIP goals for the generation business segment are based on the actual performance of Cinergy's generation fleet and the individual generating station where the respective employees work. *Id.* at 12-14.

The NEIP is available to exempt and non-exempt employees of PSI and Cinergy Services who do not participate in another incentive plan. The NEIP is a short-term incentive plan, according to Mr. Verhagen, that allows employees to receive cash payments if Cinergy Corp. attains certain corporate performance goals during the calendar year. Mr. Verhagen testified the purpose of the NEIP is to attract, retain and motivate employees, enhance teamwork and achieve high levels of corporate goals. This plan, like the others, is monitored by the compensation committee. The NEIP uses the same performance measures as the AIP's corporate performance measure. *Id.* at 14-15.

Mr. Verhagen testified that the UEIP is available to union employees of PSI, Cinergy Services and CPGS who do not participate in another incentive plan. Like the other plans described, the UEIP permits union employees to receive cash payments if Cinergy Corp. attains certain performance goals or if their business unit attains certain performance goals during the preceding calendar year. *Id.* at 15-16.

The purpose of the LTIP is to assist in attracting, retaining and motivating executives by keeping Cinergy's compensation package competitive and to align a portion of the executive compensation with corporate interests by encouraging and enabling executives to acquire Cinergy stock. Mr. Verhagen stated that under the LTIP certain employees may be granted an incentive and non-qualified stock options, stock appreciation rights, restrictive stock, dividends equivalent to opportunity to earn performance based shares and certain other stock-based awards. *Id.* at 17-18.

Mr. Verhagen testified that this Commission has previously considered PSI's incentive compensation plans. He said that PSI's current AIP and LTIP are similar to the AIP and performance share plans previously reviewed in Cause No. 40003. In addition, PSI's AIP and performance share plans were considered in Cause Nos. 37414-S2 and 38809 (1989) and Cause Nos. 39584 and 39584-S2 (1994). He stated that in each case the proceedings resulted in PSI's rates reflecting incentive compensation costs. *Id.* at 19. Mr. Verhagen stated that incentive compensation is a necessary component of any company's compensation and benefit package in order to keep total compensation competitive. He pointed out that many utility companies and non-utility companies offer these types of incentive compensation plans. PSI must offer such plans in order to remain competitive and be able to attract and retain a high caliber workforce. In addition, PSI's incentive compensation plans pay out reasonable levels of incentive

compensation. For these reasons, Mr. Verhagen believed that it is appropriate for PSI to reflect these costs in its rates. *Id.* at 20.

Mr. Verhagen also discussed the allocation of the costs of the various compensation plans to PSI. He said that PSI recognizes that this Commission has required shareholders to bear a portion of the incentive compensation costs. He also recognizes that Cinergy's shareholders, as well as its customers, benefit from the achievement of the goals used in these incentive compensation plans. Mr. Verhagen stated that the costs of the corporate goals under the AIP and EMBU AIP, were allocated 50% to the shareholders, 50% to the customers. The individual goals and the RBU goals under the AIP were allocated 100% to the customers. The EMBU AIP earnings goals were allocated 50% to the shareholders and 50% to the customers. Like the AIP, the EMBU business segment goals and the individual goals were allocated 100% to the customers. For the LTIP, Mr. Verhagen stated that the total shareholder return was allocated on a 50%/50% basis. Mr. Verhagen allocated 100% of NEIP and UEIP costs to PSI's customers. *Id.* at 21-22.

The OUCC did not propose any adjustment to PSI's proposed level of incentive compensation expense to be included in PSI's rates. Mr. Carver presented detailed testimony discussing our past treatment of incentive compensation in Indiana rate cases. Pub. Ex. 1, pp. 77-80. His testimony also highlighted the significant escalation in PSI's incentive compensation costs in relation to the amount PSI has proposed to include in cost of service. *Id.* at 80-82. Mr. Carver further testified that it was unnecessary for the Commission to create unique shareholder incentive mechanisms in order to focus individual employees on achievements that enhance corporate financial objectives. Any additional shareholder incentives would not directly influence the day-to-day activities of individual employees who, on average, have about 9.8% of their compensation "at risk" through the incentive plans discussed by Mr. Verhagen. *Id.* at 82-83.

CAC presented the direct testimony of Dr. Michael Sheehan, who testified that he had five problems with PSI's executive incentive program. First, he said, the levels appeared to be excessive. Second, the underlying premise that high levels of incentive pay produce high levels of corporate performance has not been substantiated. Third, he said, not only do incentives appear not to work, in fact they have a tendency to produce bad behavior on the part of a significant number of executives. Fourth, he said, even if the incentives proposed by PSI might work in theory, they are usually tied to goals that have flaws or lead to misdirection. Finally, he maintained that building incentives into rates means that ratepayers are charged for incentive payments even when the incentives are subsequently not justified by performance or are not paid to employees of the utility.

Dr. Sheehan noted that under the allocation of the incentive programs proposed by Mr. Verhagen, 75% of the costs of these programs are being allocated to PSI's ratepayers which in his opinion is not appropriate, at least as the programs are applied to executives. CAC Ex. C, p. 64. First, he said the incentive programs are primarily directed to the goals of maximizing the financial performance of the holding company, Cinergy, which, in his opinion, is not an appropriate goal and embodies an intrinsic conflict of interest for PSI employees. He said that

this Commission should not allow any cost of recovery at all for the costs associated with Cinergy's financial performance. *Id.* at 64.

In support of his argument that the costs of executive incentive plans should not be allocated to PSI, Dr. Sheehan cited three articles, from researchers at the Wharton School of Business, Indiana University, and Harvard University, respectively. *Id.* at 66-68. Dr. Sheehan claimed that these studies tended to show that substantial incentives have motivated counter-productive behavior. He said that the provision of substantial incentives to Cinergy executives on loan to PSI to maximize the returns to PSI, could, in his opinion, lead to predatory behavior against PSI. *Id.* at 69. He said that if the Commission approves the allocation of the costs to PSI, it should only be done in conjunction with the creation of a tracker or true-up mechanism. Otherwise, in cases where the goals are not met and the anticipated ratepayer benefits are not forthcoming, and thus the costs are not offset, the ratepayers will still have to fund the full cost of the incentive programs and Cinergy will "pocket the money." Dr. Sheehan conceded during cross-examination that he had not read the Wharton study prior to preparing his testimony, and that these studies did not support his opinions in several key respects. For example, he indicated that the Harvard study was based on the "rent extraction" theory, which is a minority theory in the field of incentive compensation. In addition, the Indiana University study did not differentiate whether the stock options it studied were paid as part of a base compensation package or incentive pay to motivate a desired behavior.

In response, Mr. Verhagen pointed out that Dr. Sheehan performed no analysis of the programs involved in this case. On the other hand, Towers Perrin Company ("Towers") had analyzed Cinergy's executive compensation programs and concluded that: (1) Cinergy's total annual executive compensation is competitive with the proxy peer group at the 50th percentile; and (2) the long-term incentives paid by Cinergy in 2002 were only 66% of the level of long-term incentives paid by the proxy peer group at the 50th percentile and 33% of the long-term incentives paid by the proxy peer group at the 75th percentile. In Mr. Verhagen's opinion, these studies show that Cinergy's compensation programs result in reasonable levels of compensation when compared to its proxy peer group. Pet. Ex. MM, p. 2.

Mr. Verhagen pointed out that Dr. Sheehan presented no evidence to support his conclusion that the structure of PSI's incentive compensation program is flawed because it motivates executives to accomplish goals contrary to PSI's best interests. Mr. Verhagen said that PSI's interest and Cinergy's interests are interwoven and inseparable. He noted that the AIP for the RBU has performance goals based on electric service reliability, safety and customer satisfaction and that these goals are obviously in the best interest of PSI customers. *Id.* at 3-4.

Mr. Verhagen stated that Dr. Sheehan erred in contending that performance goals based on the corporate performance and total shareholder return are contrary to the interests of PSI's customers. Over the long term, he said, Cinergy Corp. could not favor shareholders interest over the interest of PSI customers. Doing so would ultimately cause PSI's service level to deteriorate, which would produce widespread customer dissatisfaction. This would ultimately reduce Cinergy Corp. net income and total shareholder return. *Id.* Mr. Verhagen also responded to Dr. Sheehan's statement that the portion of the incentive expense allocated to PSI is not appropriate.

Mr. Verhagen stated that PSI's *pro forma* adjustment strikes a reasonable balance as the costs of AIP performance goals related to corporate performance and the total cost of the LTIP are allocated 50% to shareholders and 50% to customers. He said such an allocation is reasonable given that the performance goals provide inexplicably intertwined benefits to shareholders and customers and these incentive programs result in total compensation levels that are reasonable and necessary to attract talented employees.

(b) Discussion and Findings. It is commonly accepted that incentive compensation plans may be necessary in order for utilities to attract and retain highly qualified individuals. Dr. Sheehan does not dispute this fact. Instead, he generally objects to PSI's *pro forma* executive compensation adjustment on two grounds: (1) there is no showing that executive compensation plans enhance employee performance; and (2) the percent of the expense allocated to PSI is not appropriate.

Dr. Sheehan cites three business journal articles in support of his conclusion that there is not a link between incentive compensation and corporate performance. The first article surveyed several studies on the relationship between corporate performance and the levels of equity ownership by a firm's management and concluded that the studies were mixed as to whether increased equity ownership produced improved firm performance. The second article was admittedly a minority view and was predicated on the "rent extraction theory" in executive compensation. The final article cited by Dr. Sheehan is also a minority view, which leads us to the conclusion that the majority view is that there is a direct link between executive compensation and improved corporate performance.

As to Dr. Sheehan's objections regarding the level of costs assigned to the PSI shareholders, we have previously approved the recovery of incentive compensation costs through rates where: (1) the incentive compensation plans are not pure profit-sharing plans, but rather incorporate operational as well as financial performance goals; (2) the incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. PSI's incentive compensation plans incorporates operational goals as well as pure profit sharing goals. The Towers study demonstrates that these incentive compensation plans are not excessive and are reasonable to attract and retain the employees required to manage and operate PSI. Accordingly, we find that PSI's *pro forma* adjustment for employee incentive compensation is appropriate and should be approved.

(10) Voluntary Early Retirement Program Expense.

(a) Evidence. PSI proposed an adjustment to its test year Voluntary Early Retirement Program ("VERP") expense. It proposed to eliminate the actual 2002 VERP expense of \$19,100,000 and replace it with a representative level of annual VERP expense of \$5,389,000. Pet. Ex. Y-6, Sch. C-3.9. Mr. Howe sponsored this adjustment on the basis that all related employee expense levels in this case reflect the reduced number of employees resulting from PSI's VERP. It is only appropriate, he said, to reflect the corresponding costs of those employee reduction programs over the years for which rates approved in this case will be in effect,

especially when such costs are less than the corresponding cost savings (benefits) proposed to be reflected in PSI's rates. Pet. Ex. Y, pp. 6-7.

Mr. Verhagen testified that from 1995 through 2001, PSI offered five different VERPs to reduce employees. Pet. Ex. R, pp. 38-39. In 2002, he said, PSI offered three separate VERPs which essentially offered enhanced retirement benefits to those employees who accepted early retirement. *Id.* at 39. Mr. Verhagen stated that of the 425 employees eligible to participate in the Company's 2002 VERPs, 302 employees accepted the Company's offer.

OUCG witness Carver proposed to eliminate PSI's VERP adjustment, thereby eliminating from rates any VERP expenses. Pub. Ex. No., 3, Adj. C-13. Mr. Carver did not dispute the wisdom of, or need for, VERPs. Pub. Ex. No. 1, at 40. Nor did he question the recurring nature of these expenses. Tr. at P62-P63. Rather, the basis for his disallowance was his opinion that because the reduced expenses have been experienced since 2002, but will not be reflected in rates until April, 2004, PSI's shareholders have already received some of the benefits of the VERPs. *Id.* at 41. Mr. Carver claimed that the Company was seeking a deferral and amortization of the actual 2002 VERP expenses, and that it was not appropriate to recover from customers the costs of the VERPs on a prospective basis when PSI does not propose to flow through to customers the related savings on a retroactive basis. Mr. Carver estimated these retroactive savings to be \$16.9 million. As an alternative to complete disallowance, Mr. Carver proposed that PSI be allowed to amortize over four years the difference between the 2002-03 expense of \$21.554 million and the pre-2004 savings estimate of \$16.9 million.

In response, Mr. Howe pointed out that PSI's salaries and wage expense in this case eliminated all of the former employees who elected to take the 2002 VERP, even if those people had not yet left the Company. Pet. Ex. PP, pp. 5-6. He clarified that PSI was not seeking a deferral and amortization of the actual 2002 VERP expenses, but rather, PSI was seeking to have a representative level of VERP expenses built into future rates. At the hearing on PSI's rebuttal case, Mr. Howe indicated that he has checked the reasonableness of his proposed annual VERP amount. He indicated that PSI has conducted six VERP offerings in the last five years, with an average annual cost of approximately \$5.6 million. He also noted, that since PSI filed its case-in-chief testimony, the Company has instituted another VERP program in 2003 at a cost of about \$4 million. Mr. Howe indicated that this evidence supports PSI's proposed annual VERP expense of approximately \$5.4 million. Tr. at Y34 – Y35.

(b) Discussion and Findings. In order to frame the issue for our consideration, PSI proposed to eliminate the actual 2002 VERP expense of \$19,100,000 and replace it with a representative level of annual VERP expense of \$5,389,000. Pet. Ex. Y-6, Sch. C-3.9. The OUCG's proposed adjustment, taken in conjunction with PSI's adjustment, would serve to eliminate VERP expenses from rates. Pub. Ex. No., 3, Adj. C-13. In order to undertake our review of this issue, we accept PSI's VERP adjustment as the appropriate starting point for our consideration and resolution of this issue.

Based on our review of the evidence presented on this issue, PSI appears to have premised its pro forma adjustment on a methodology that would effectively amortize the cost of

its 2002 VERP over a four-year period. While we recognize that costs rise and fall between rate cases, the pro forma adjustment developed by PSI, which projects future costs (but not savings) from programs that may or may not occur, fails to fully address many issues, including: the anticipated level of any future workforce reduction programs; the costs associated with the programs; and, the anticipated level of overall savings associated with the implementation of future VERPs.

In evaluating PSI's request for a *pro forma* adjustment for VERP expenses, we recognize that implicit in undertaking VERPs is the expectation that there will be short term costs and possible long term savings associated with the programs. Accordingly, in undertaking our review of this issue we must consider the anticipated future level of such programs in conjunction with any cost savings that may occur as a result of the programs. Based on the evidence presented, we cannot determine, with any degree of certainty the actual level of costs and savings associated with the possible implementation of future VERPs. Therefore, we accept the OUCC's adjustment and find that VERP expenses should not be included in rates.

(11) Property Taxes.

(a) Evidence. PSI's *pro forma* operating expenses included an adjustment of \$151,000 to test period property taxes. Pet. Ex. X-23, as revised by the August 31, 2003 cut-off date update filing. PSI witness Farmer sponsored this adjustment and included the tax law changes noted in the testimony of PSI witness Charles J. Winger.

Mr. Winger explained that the 2002 Indiana General Assembly legislated changes in the manner that required Indiana property taxes to be re-calculated for the actual 2002-pay 2003 tax year. Pet. Ex. Q, p. 7; Pet. Ex. X, p. 29. Mr. Winger testified that property tax is a function of two basic factors: (1) the assessed value of real and personal property; and (2) the property tax rate. Pet. Ex. Q, p. 11. PSI estimated the assessed value of its real and personal property to be \$1,301,708,000, which represented actual plant balances as of September 30, 2002, plus *pro forma* adjustments for plant additions, retirements and estimated changes in material, supplies and fuel inventories, as determined by Mr. Farmer. Mr. Winger estimated the tax rate to be 2.49%. He started with the actual 2001-pay 2002 average tax rate for PSI of 2.64% and adjusted it downward by 5.7%. This downward adjustment was determined by comparing the average Indiana statewide net tax rate for the 1994-pay 1995 to the same rate for the 1995-pay 1996, the last time that Indiana experienced a statewide reassessment of real property.

Mr. Farmer took into account the information provided by Mr. Winger and accounted for the *pro forma* plant additions and retirements listed on Schedule B-2, the adjustment to the coal stock inventory from Schedule B-4 and the adjustment to the material and supplies inventory from Schedule B-6. He also estimated a payment in lieu of taxes applicable to the Madison Generating Station, in the amount of \$952,000, and he eliminated 50% of the Child Care Center property taxes. These changes resulted in a *pro forma* total property tax expense of \$31,421,000 and an adjustment to test year operating expense of \$151,000. Pet. Ex. X-23, updated October 6, 2003.

OUCU witness Carver proposed the elimination of Mr. Farmer's adjustment to test year property taxes. Pub. Ex. No. 3, Adj. C-19. Mr. Carver did not necessarily disagree with PSI's calculations. Rather, he said, the basis for his disallowance is the delay that has been experienced statewide in the finalizing of assessed values, tax rates and tax bills. Pub. Ex. No. 1, p. 104. Mr. Carver's adjustment was a "placeholder" until more complete property tax data becomes available in August and September, 2003, he said. Mr. Carver proposed that the property tax annualization be updated as an exception to the Prehearing Conference Order. Pub. Ex. No. 1, pp. 107-108. He proposed that: (1) PSI update its calculations for actual tax bills; (2) update Schedule WPC-3.38c to reflect final and provisional tax bills; (3) if any provisional tax bill exceeds 50% of the previous tax bill, reduce such amount to reflect the lesser of 50% of the prior tax bill or the 2001 total tax bill adjusted to reflect the composite net increment/decrement for all other counties with final tax bills; and (4) identify all counties that have failed to provide final or provisional tax bills and the annualization for these counties should be based on the 2001 tax bill adjusted in the manner called for in item (3).

Mr. Farmer opposed Mr. Carver's proposal and noted that the 2001 tax liability is primarily based upon the assessed value of property at December 31, 2000. Pet. Ex. QQ, pp. 34-37. The problem with Mr. Carver's proposal is that these assessed values will not be matched or synchronized with the value of plant included in this case and therefore will likely not be representative of an ongoing level. Mr. Farmer further observed that changing the property tax valuation method to fair value will not have a significant impact on PSI property assessments, because over 90% of PSI's assessed value is made up of property referred to as "state board distributable" property. The assessed value of such property is predicated on the net tax basis of the property (net book value) as recorded on the Company's books. In Mr. Farmer's view, it would be inappropriate to use the net book values as of December 31, 2000, as proposed by Mr. Carver, given that the test period in this case is based on a 2002 test period pro forma into 2003. Mr. Farmer opined that the December 31, 2000 property evaluation and assessments are stale and do not provide the proper matching of plant costs included in the rate base in this case. *Id.* Mr. Farmer also testified that Mr. Carver's proposal to use the lesser of 2001 pay 2002 tax or the 2001 tax adjusted for some net increment/decrement is also flawed because the basic presumption behind Mr. Carver's proposal is that the 2002 pay 2003 tax bills in all counties will change from the prior year by the same percentage relationship.

As an alternative to Mr. Carver's proposal, Mr. Farmer proposed that the Company's proposed retail jurisdictional portion of property tax expense (\$30,100,000) should be included in PSI's base rates. *Id.* at 38-39. If the jurisdictional portion of any future annual property tax expense, using allocators approved in this case, is less than \$30,100,000, PSI will return to customers the amount by which the base level exceeds the jurisdictional portion of property tax actually billed and charged to expense. PSI will return any excess amount to customers through one of PSI's tracking mechanisms that allocate costs based on demand allocators, since property tax is allocated based on demand. (*i.e.*, CWIP tracker, Clean Coal Operating Cost tracker, or Summer Reliability Tracker). This credit mechanism would continue until the first year that PSI's actual property tax expense exceeds the amount included in base rates, at which time the crediting would end for that and all succeeding years.

(b) Discussion and Findings. This Commission is certainly cognizant of the uncertainty facing millions of property owners, including public utilities, created by the statewide reassessment mandated by the Indiana courts and the General Assembly. We appreciate the creativity of the parties in attempting to deal with these uncertainties. After considering all of the evidence, we are persuaded that Mr. Farmer's rebuttal proposal should be adopted. Importantly, this ensures that PSI's customers will pay no more than PSI's actual property tax expense for a given year. Another advantage of this proposal is the administrative ease by which it can be implemented and reviewed by this Commission and any party of interest. Given that PSI's actual 2001–pay 2002 tax is within \$151,000 of PSI's proposed property tax level, and that PSI has added significant taxable property since 2001, we find it reasonable for PSI to include its proposed property tax expense in base rates and to implement its proposed reconciliation and crediting mechanism, utilizing the CWIP tracker, Standard Contract Rider No. 62.

(12) Trading Expense.

(a) Evidence. PSI proposed an adjustment to test period expenses related to certain trading expenses. Mr. Farmer testified as to a representative level of trading expense based on actual test period amounts. Pet. Ex. QQ, pp. 39–40. He stated that PSI's July 31, 2003 update removed \$5,124,000 in trading expenses for trading floor rent, building expense and other trading related costs that were charged to test period expense. A portion of this *pro forma* adjustment (approximately \$3.9 million) was removed from test period expenses, not because it was not representative or properly allocated to PSI, but because of the existence of an explicit off-system sales profit sharing mechanism included in PSI's proposed Summer Reliability Tracker. PSI's rationale for excluding this portion of the trading expenses was that there were likely incremental O&M expenses embedded in its test period expenses associated with maximizing off-system sales profits. Because incremental O&M expenses associated with maximizing off-system profits are not separately identified or accounted for on PSI's books and records, these trading expenses are intended to serve as a proxy for the potentially embedded incremental O&M costs. PSI reasoned that, if the explicit off-system profits incentive sharing mechanism in its proposed Summer Reliability Tracker is approved and implemented, it would be appropriate to remove these “proxy” incremental O&M expenses. Conversely, PSI stated that if the proposed Summer Reliability Tracker is not approved, it would be appropriate to include these trading expenses in PSI's revenue requirements.

Mr. Farmer explained that these expenses represent personnel and systems costs that are properly allocated to PSI based upon PSI's use of trading personnel for both off-system purchases and sales. These expenses consist of costs related to power trading functions; rent and building expense; salaries, benefits and expenses for confirmation and billing functions; generation and supply scheduling; costs of transmission scheduling and congestion management; Information Technology support; trading expenses in the Midwest; and general management of trading activities. Mr. Farmer testified that these expenses result in a total cost of \$3,953,000. Mr. Farmer indicated that the remainder of the expenses eliminated by PSI in its July 31, 2003 update (\$1,171,000) did not support PSI's off-system sales activities and therefore should be

excluded from PSI's revenue requirements with or without approval of the Summer Reliability Tracker. Pet. Ex. QQ, p. 40.

The OUCC, while opposing the Summer Reliability Tracker and the explicit incentive sharing mechanism for off-system profits, made no corresponding adjustment for PSI's elimination of the related trading expenses. Mr. Brosch surmised that the trading cost exclusion remained appropriate even if PSI off-system sales are not tracked because the implementation of the JGDA results in PSI being more insulated from trading results in that all new off-system sales of PSI energy occur through intercompany transfers to CG&E.

(b) Discussion and Findings. Consistent with our determination that test-period off-system sales profits of \$18.7 million should be included in base rates, and that an amount for trading expenses should be reflected in a corresponding reduction of the amount included in base rates, we find that PSI's *pro forma* expenses shall include \$3,953,000 for trading expenses.

(13) Deferred Costs.

(a) Deferred Dynegy Buyout Costs.

(i) Evidence. In 1999, PSI and the OUCC entered into a Settlement Agreement pertaining to a buyout of PSI's Gasification Services Agreement with Dynegy Power Corp. – an agreement whereby Dynegy provided PSI with synthetic gas for use at PSI's Wabash River Coal Gasification Repowering Project ("WRCGRP"). This Commission, in an order dated September 9, 1999 in Cause No. 41468, approved the PSI/OUCC Settlement Agreement. Pursuant to this settlement agreement, PSI was authorized to recover the costs of the contract buyout fee, "Costs to Achieve" (additional costs to implement the buyout transaction, specifically, the costs involved in converting the WRCGRP to use both natural gas and syngas), and carrying costs on the unamortized balance of the buyout fee and the costs to achieve, over an 18-year period (the "Dynegy Buy-out Amortization"). Pet. Ex. X, pp. 22-23; Settlement Agreement, Cause No. 39312, pp. 3-4 (PSI Motion for Administrative Notice Filed May 30, 2003).

In this case, PSI proposed an upward adjustment of \$928,000 to the annual Dynegy Buy-out Amortization. Pet. Ex. X-14, Sch. C-3.25. Mr. Farmer explained that this adjustment reflects the transfer of certain plant installed in the WRCGRP conversion process from the Dynegy Buy-out Amortization amount to PSI's rate base, and the "true-up" of the costs to achieve to the actual costs incurred by PSI in connection with the buyout and conversion. Pet. Ex. X, p. 22.

OUCC witness Brosch, in OUCC Adjustment C-9, proposed a \$2,651,000 reduction in PSI's total Dynegy Buy-out Amortization expense, citing a number of perceived problems with PSI's calculations underlying the unamortized amount. First, Mr. Brosch objected to the capitalization of labor costs within the deferred costs to achieve, theorizing that such capitalization could lead to a double recovery of labor costs that were reflected in PSI's rates in

Cause No. 40003. Pub. Ex. No. 2, p. 79. Accordingly, Mr. Brosch removed \$981,608 in capitalized labor costs that were incurred to convert the facility to a dual fuel plant. Pub. Ex. No. 2, pp. 81-82. Second, Mr. Brosch objected to PSI's calculation of the Buy-out Amortization amount because he believed the Amortization amount should be calculated to reflect tax savings created by the deductibility of the one-time buy-out cost of \$246.7 million. *Id.* Mr. Brosch stated that PSI is calculating carrying costs on the entire buy-out amount of \$246.7 million, even though its actual cash outlay was \$146.7 million, by his calculations, after taking into consideration his estimate of the associated tax benefits. According to Mr. Brosch, customers have received no benefit from the income tax deferrals, because there has been no rate case to account for changes in capital structure and capital costs since Cause No. 40003. *Id.* at 84. Mr. Brosch thus calculated carrying charges on the buy-out amount *after* deducting his estimated tax benefits. *Id.* at 84-85.

In response, Mr. Farmer indicated that there is no double recovery, real or potential, of labor costs. Pet. Ex. QQ, pp. 22-24. He pointed out that labor costs associated with construction projects are capitalized and are not treated as an ongoing expense for ratemaking purposes – a point that Mr. Brosch generally agreed with on cross-examination. Pet. Ex. QQ, p. 22; Tr. at Q25-Q28. Mr. Farmer explained that Mr. Brosch's labor adjustment assumes that the labor force involved in the conversion came from the labor pool, the costs of which were expensed in the last rate case as non-construction, as opposed to the pool of employees the costs of which were capitalized. Mr. Farmer pointed out that Mr. Brosch has provided no support for this assumption. In fact, as Mr. Farmer explained, in PSI's last rate case, 22% of the Company's labor costs were capitalized. Mr. Farmer also pointed out that capitalized labor costs are ultimately recovered from customers over time in the form of depreciation expense. Hence, he said, there is no double recovery of labor costs because the labor costs incurred during the conversion are likewise recovered over time through the Buy-out Amortization, not as an ongoing level of expense. Pet. Ex. QQ, pp. 22-24.

As to Mr. Brosch's proposal to reflect tax benefits as a reduction in the amount to be recovered through the Buy-out Amortization, Mr. Farmer explained that the entire basis for Mr. Brosch's adjustment (*i.e.*, that customers have not benefited from the income tax deferrals because the transaction occurred between rate cases) is incorrect. Customers have, in fact, received benefits. Pet. Ex. QQ, p. 26. Mr. Farmer cites three changes in PSI's rates related to the recovery of carrying charges on qualified pollution control property that utilized PSI's updated cost of capital – including the tax benefits cited by Mr. Brosch. Mr. Farmer testified that each updated cost of capital included zero cost deferred income taxes as recorded on the Company's books, including the Dynegy deferred income taxes related to the Dynegy buyout. Mr. Farmer calculated this benefit as producing \$1,102,000 in annual savings to customers. Pet. Ex. QQ, p. 27. Mr. Farmer pointed out that if Mr. Brosch's adjustment were accepted, customers would receive benefits from Dynegy deferred taxes twice: once through the reduction in the amortization of the Dynegy regulatory asset, and a second time through calculation of CWIP revenues. *Id.* In addition, Mr. Farmer pointed out that Mr. Brosch only considered the cash flow implications of the Dynegy deferred income taxes up until the assumed order date in this proceeding, without looking beyond the cash flow implications after the order in this proceeding.

For example, Mr. Farmer explained that, the cash flow benefit of the Dynegy tax deduction decreases over time as the deferred taxes payback.

With regard to Mr. Brosch's elimination of depreciation expense when calculating interest and the regulatory asset amortization, Mr. Farmer observed that the Settlement Agreement in Cause No. 41468 clearly states that PSI is entitled to recover "costs to achieve" in addition to recovery of carrying charges on the unrecovered amounts. Pet. Ex. QQ, pp. 28-29. Thus, according to Mr. Farmer, PSI is entitled to recover a return on, as well as a return of, PSI's actual costs to achieve.

(ii) Discussion and Findings. The outcome of this dispute is determined by our approval of the provisions of the Settlement Agreement and basic utility ratemaking principles. The Settlement Agreement provides that PSI shall be entitled to recover, over an 18-year period, the Indiana retail jurisdictional portion of the Buy-Out Fee, including estimated costs to achieve. The Settlement Agreement further provides that PSI shall also be entitled to recover carrying costs on the unamortized balance of such amount. In short, this provision provides that PSI is entitled to a return of (*e.g.*, labor and depreciation expense), and a return on (*e.g.*, carrying costs), its investment associated with the Dynegy buy-out.

The Settlement Agreement expresses the intent that PSI be allowed to recover all of the costs associated with converting the WRCGRP to natural gas. To the extent that labor costs were incurred as part of the conversion project, Mr. Farmer demonstrated that such costs were capitalized and were properly recorded as costs to achieve. Pursuant to the Settlement Agreement, PSI is entitled to recover these labor costs through amortization. The same conclusion for depreciation (PSI's capital investment) is inescapable under the Settlement Agreement. In fact, Mr. Brosch agreed on cross-examination that both labor and depreciation (capital investment) costs were incurred by PSI in connection with the conversion of the WRCGRP to natural gas use. Significantly, while Mr. Brosch proposed to exclude both labor and depreciation costs from the amortization calculations, he confirmed that depreciation costs were a part of PSI's initial 1999 estimate of costs to achieve.

In sum, we decline the invitation to reopen the Settlement Agreement entered into between PSI and the OUCC, and find that PSI's adjustment for the Dynegy Buy-out Amortization is reasonable and should be accepted.

(b) Merger Costs.

(i) Evidence. In this case, PSI proposed a *pro forma* adjustment of \$7,419,000 for unrecovered merger transaction costs and costs to achieve merger benefits incurred through October 31, 1996. This *pro forma* adjustment was designed to allow PSI to recover its total unrecovered merger-related costs of \$46,206,000 over a four-year period. Mr. Howe sponsored the annual amortization amount of \$11,559,000. Pet. Ex. Y-12, Sch. C-3.16.

PSI witness Steffen explained that this Commission, in Cause No. 40003, determined that PSI's deferred merger transaction costs were reasonable, and authorized PSI to recover the

merger transaction costs deferred through January, 1995 (\$23.7 million) over a 10-year period (\$2.4 million per year), beginning October 1, 1994. Pet. Ex. C, p. 25. He testified that as of the applicable cut-off date, PSI's unrecovered deferred merger transaction costs will approximate \$2.6 million. PSI proposes to amortize the projected unamortized balance of merger transition costs over four years.

Mr. Steffen further testified that this Commission in Cause No. 40003 authorized PSI to recover in rates its costs to achieve merger savings incurred up to August 31, 1995 (\$17.7 million), amortized over a 10-year period, and to defer, for subsequent recovery, its costs to achieve merger savings incurred after August 31, 1995 until October 31, 1996. Pet. Ex. C, p. 26. Mr. Steffen stated that the Company's incurred costs to achieve merger savings consisted primarily of the costs of voluntary workforce reductions programs, relocation, information systems consolidation and re-engineering efforts associated with the consolidation of operations. *Id.* He also testified that the recovery of such costs was reasonable and consistent with the Settlement Agreement and Orders in Cause No. 40003, because they were required to complete the merger and realize the related merger benefits reflected in PSI's proposed revenue requirement. *Id.* at 27.

OUCG witness Brosch proposed to significantly reduce PSI's proposed adjustment, so as to lengthen the recovery period from four additional years (PSI's proposal) to ten additional years – without carrying costs. Pub. Ex. No. 3, Adj. C-10. Mr. Brosch rationalized this additional 6-year recovery period on the basis that PSI retained the labor savings realized from 1997 through 2003 for its shareholders and now proposes to charge customers, over a 4-year period, the costs that generated such savings. Pub. Ex. No. 2, p. 97.

In rebuttal testimony, Mr. Howe disputed Mr. Brosch's proposal that PSI recover its merger savings costs over ten years, without carrying charges. Pet. Ex. PP, pp. 7-8. He noted that the Settlement Agreement and the related Commission Order in Cause No. 40003 approved a total amortization period of ten years, and that PSI's adjustment even increases the recovery period by one year. By comparison, he pointed out, Mr. Brosch's adjustment increases the recovery period to a total of 16 years.

(ii) Discussion and Findings. Pursuant to several settlement agreements and orders, we have previously recognized that PSI is entitled to recover merger transaction costs, and costs to achieve merger savings incurred up until October 31, 1996, over a 10-year period. Mr. Brosch does not dispute the reasonableness of these deferred merger savings costs, nor does he dispute the entitlement of PSI to recover these costs. Instead, Mr. Brosch argues that since the related merger savings were not reflected in the Company's rates during the deferral period, the amortization period agreed to by the OUCG in Cause No. 40003 should be extended by six additional years. As we have previously authorized PSI's recovery of these incurred costs over a 10-year period we find that the Company's proposed adjustment reflects a consistent application of the previously-approved settlement agreements and orders. Accordingly, we approve PSI's proposed *pro forma* adjustment on this issue.

(c) Amortization of Midwest ISO-Related Deferred Costs.

(i) Evidence. PSI proposed recovery, via a four year amortization, of the deferred MISO administrative costs, consistent with this Commission's December 1, 2002, Order in Cause Nos. 42257 and 42266, which authorized the deferral of certain costs incurred as a result of taking transmission service for retail customers under the Midwest ISO open access transmission tariff ("OATT"). In entering that order, we approved a Settlement Agreement among PSI, Vectren Energy Delivery of Indiana, Inc., Indianapolis Power & Light Company and the OUCG that allowed PSI and the other utilities to defer ongoing Midwest ISO Administrative Adder Costs (i.e., costs incurred under Midwest ISO Schedules 10 and 10-B), for subsequent recovery in a base rate case from Indiana retail customers, over a four-year amortization period. Pet. Ex. Z, pp. 29-30.

OUCG witness Mr. Carver originally opposed the recovery for the reason that the "MISO cost deferral and amortization recovery request does not appear to represent either the net cost incurred by the Company or ongoing expense levels." Pub. Ex. No. 1, pp. 51-53. Mr. Carver testified that, the Company experienced a rather notable increase in 2002 transmission revenues in comparison to 2001 and that this increase over 2001 appears to have been maintained during 2003. *Id.*, at 56. Mr. Carver concluded that because PSI had the benefit of these increased revenues, it should be denied recovery of the deferred costs.

On rebuttal, PSI witness Kent K. Freeman pointed out that the assumption upon which Mr. Carver based his position, namely that "PSI has realized a significant increase in transmission revenues," was unfounded. In comparing later periods to 2001, Mr. Carver had failed to include all transmission revenues which are included in two different account numbers, – accounts 447850 and 456850. Pet. Ex. RR, p. 2. Mr. Freeman observed that, if the overlooked revenue from account 447850 had been included for the calendar years 2001 and 2002 and year-to-date August, 2003, Mr. Carver would have seen that there was *not* a significant increase in transmission revenues in 2002 over 2001. *Id.* at 3. Indeed, including revenues from both accounts for all three periods showed that PSI transmission revenues had *decreased* in both 2002 and year-to-date 2003. *Id.*

Additionally, Mr. Freeman observed that Mr. Carver, failed to take into account the substantial benefits that the Midwest ISO has provided to PSI's customers, as discussed in the testimony of PSI witness Ronald R. Jackups, Pet. Ex. M, pp. 23-26, and as observed by this Commission in its final order entered in Cause Nos. 42027 and 42032 (*Ind. Util. Reg. Comm'n*, December 17, 2001), approving the transfer to the Midwest ISO of functional control of operation of PSI's transmission facilities. These benefits, he said, include, among other things, the substantial benefits of increased market competition and elimination of pancaked transmission rates within the Midwest ISO. *Id.*

In reaction to Mr. Freeman's testimony, Mr. Carver presented a Revised Pub. Ex. No. 3, which, in effect, accepted PSI's amortization of deferred MISO costs. Mr. Carver admitted that his adjustment to Schedule C-14 was intended to allow PSI recovery of the full amount of its

proposed MISO amortization. Tr. at P70. On direct examination at the hearing, Mr. Freeman indicated that it was his understanding that Mr. Carver had intended to accept PSI's proposal, but that in order to do so, Mr. Carver needed to make one minor adjustment to his schedule. Mr. Carver had made an adjustment to the *pro forma* level to eliminate the portion related to PSI's wholesale customers. However, when the deferred balance was updated through August 31, 2003, PSI had removed the wholesale portion from the account, correcting the error. Thus, Mr. Carver's adjustment was no longer necessary.

(ii) Discussion and Findings. It appears based on the foregoing, that there is no current dispute over the appropriateness of including the four-year amortization of deferred MISO expenses. We therefore accept PSI's adjustment in this case to recover over four years its deferred Midwest ISO-related administrative costs.

(d) Post-In Service (Deferred) Depreciation and AFUDC.

(i) Evidence. Mr. Carver sponsored OUCC Adjustments B-1 and C-18. Adjustment B-1 adjusts PSI's Schedule B-3, which includes in PSI's rate base an estimate, subject to true-up, of the August 31, 2003 book balance related to the post-in-service capitalization of carrying costs and depreciation expense. Adjustment C-18 adjusts the Company's Schedule C-3.37, which reflects the Company's *pro forma* amortization of deferred depreciation and AFUDC/carrying cost continuation on estimated deferral balances as of August 31, 2003.

(ii) Discussion and Findings. The sole basis for these adjustments was Mr. Carver's utilization of Mr. Majoros' depreciation rates instead of the depreciation rates sponsored by Mr. Spanos. Public's Ex. No. 1, p. 103. Given our findings above with respect to PSI's depreciation in this order it is not appropriate to make further adjustments.

(14) Interest Synchronization. Mr. Carver sponsored OUCC Adjustment C-20, which synchronized the interest deduction for income tax purposes with the OUCC's weighted cost of debt and rate base recommendations. As Mr. Carver made clear, however, the only reason for this adjustment is that the OUCC utilized a different rate base and cost of capital than PSI. Pub. Ex. No. 1, p. 111. He indicated that if the Commission ultimately adopts a rate base and cost of capital different than that proposed by the OUCC or PSI, interest synchronization should be recalculated, using the Commission's findings. Thus, there is really no issue here. The Commission's revenue requirement ultimately approved here will include interest synchronization that is consistent with the rate base and cost of capital approved herein.

E. Conclusion. On the basis of the foregoing, we find that PSI's *pro forma* jurisdictional electric net operating income under present rates, adjusted to a level which fairly represents its current operations, is \$196,564,000, summarized as follows:

Operating Revenues	\$1,284,140,000
Operating Expenses and Taxes:	
Fuel Expense	378,286,000
Purchased & Exchanged Power Expense	(5,228,000)
Other Operation and Maintenance Expense	386,214,000
Operating Revenue Deduction	(28,917,000)
Depreciation and Amortization Expense	218,316,000
Taxes Other than Income Taxes	58,415,000
Federal and State Income Taxes	80,491,000
Total Operating Expenses and Taxes	<u>\$1,087,576,000</u>
Net Operating Income	<u>196,564,000</u>

When applied to the fair value rate base determined for Petitioner in Finding No. 4C above, this operating income produces a return of only 4.05%, which is outside the range established in Finding No. 5C. In addition, the return on Petitioner's original cost depreciated rate base would be 5.37%, which is below the Commission's determination of 7.30%. Accordingly, on the basis of the evidence and the foregoing determinations, we find that the electric operating income to Petitioner, under its present rates for the electric utility service rendered and to be rendered by it, is not sufficient to provide Petitioner a fair return upon the fair value of its electric properties used and useful for the convenience of the public. Therefore, Petitioner's current rates are unjust and unreasonable.

7. **Rate Level to be Authorized.** We find that a net operating income of \$267,500,000 is hereby found to be a fair return upon the fair value of Petitioner's electric property used and useful and reasonably necessary for the convenience of the public. This provides a fair rate of return of approximately 5.51% which is within the range of reasonableness established in Finding No. 5C. In order to provide such utility operating income, an increase in Petitioner's gross annual retail electric operating revenues to \$1,406,596,000 is required. The increase in revenues will give rise to increased tax expense and as a result, total operating expenses will be \$1,139,096,000. On that basis, we find that Petitioner's *pro forma* operating results will be:

Operating Revenues	\$1,406,596,000
Operating Expenses and Taxes:	
Operation and Maintenance Expenses	731,041,000
Depreciation and Amortization Expenses	218,942,000
Taxes Other than Income Taxes	60,129,000
Federal and State Income Taxes	128,984,000
Total Operating Expenses and Taxes	<u>\$1,139,096,000</u>
Net Operating Income	<u>\$267,500,000</u>

Our findings as to the appropriate level of *pro forma* operating results are based on the evidence of record and giving appropriate weight to the need for Petitioner to maintain and support its credit, to attract capital necessary to discharge its public duties and to earn a return commensurate with that earned by enterprises of corresponding risk. We find that rates estimated to produce these results are just and fair and should allow Petitioner the opportunity to earn a reasonable return on its property dedicated to providing electric utility service to the public. Accordingly, on the basis of all of the evidence and the foregoing determinations, we find that the retail electric rates authorized herein for the electric utility service rendered, and to be rendered, should provide a fair return on the fair value rate base of its electric properties used and useful for the convenience of the public, and therefore are just and reasonable.

8. Revenue Allocation.

A. Jurisdictional Separation and Retail Cost of Service Studies.

(1) Evidence. PSI submitted the results of its jurisdictional separation and retail cost of service studies, prepared by Kent K. Freeman, PSI's Manager, Rates Services. In performing these studies, Mr. Freeman utilized the average of the 12 monthly coincident peak demands on its system ("12-CP") methodology to allocate production and transmission demand-related plant costs and expenses. Mr. Freeman testified that use of the 12-CP methodology allocates production demand related costs to each customer class on the basis of its contribution to the average of the 12 coincident monthly peaks during the test year. Pet. Ex. Z, pp. 3, 5, 19, 22 and 23. This is the same methodology that PSI has utilized, and this Commission has accepted, on numerous occasions since 1971. According to Mr. Freeman, the 12-CP method is also consistent with the FERC's allocation guidelines in PSI's case.

In performing his separation study, Mr. Freeman said that he first segregated PSI's customers into three categories: (1) one customer who purchases high pressure steam from PSI's Cayuga Generating Station; (2) wholesale customers who purchase firm power from PSI and resell it to ultimate consumers or to their members for resale (*e.g.*, WVPA and IMPA); and (3) retail electric customers who purchase firm power from PSI as ultimate consumers. *Id.* at 6. Thereafter he allocated costs among PSI's retail customers, utilizing the 12-CP method to allocate production demand related costs. Pet. Ex. Z-7 summarizes the resulting jurisdictional separation based on Mr. Freeman's studies. Pet. Ex. Z-13 summarizes the results of PSI's retail cost service study, after reflecting a proposed 33% subsidy/excess reduction. *Id.* at 28.

Nicholas Phillips testified for the PSI-IG and proposed an alternative cost of service study methodology. His methodology was based on the average of the coincident peaks in the four summer months ("4-CP"), which he contended, because PSI has been a summer peaking system in recent years, "more accurately reflect PSI's electric system and cost structure." PSI-IG Ex. No.1, p. 10. He contended that the 12-CP method is appropriate only for a system with a flat load pattern in which each of the monthly coincident peaks is relatively equal. PSI-IG Ex. No.1, p. 10.

OUCC witness Michael Brosch, supported Petitioner's use of the 12-CP method to allocate production demand related costs. He discussed the "peak and average" method to allocate such costs, which includes an energy weighting in the development of the production demand allocator, but accepted the use of the 12-CP methodology, as a "compromise between usage of fewer peak hours and utilization of an energy weighted methodology such as Peak and Average." Pub. Ex. No. 2, pp. 100-106.

In response to Mr. Phillips' proposition to utilize the 4-CP method to allocate production demand related costs, Mr. Freeman indicated that this Commission has recognized that a utility's ability to utilize valley period months to perform scheduled maintenance is a reason to use the 12-CP approach. Pet. Ex. RR, p. 12. In that regard, this Commission has stated, "the 12-CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements." *Indiana Michigan Power Company*, Cause No. 39314, (*Ind. Util. Reg. Comm'n*, October 15, 1997, at 171). Mr. Freeman defended his continued use of the 12-CP methodology and was critical of Mr. Phillips for having analyzed only system demand, without taking into account these other considerations. Pet. Ex. RR, p. 12. Mr. Freeman noted that the 4-CP methodology is used by PSI where it is appropriate -- in the tracking of purchased power costs incurred for the summer months only. Pet. Ex. RR, p. 13.

Mr. Freeman testified that the utilization of a cost allocation methodology has a major impact on the total cost of service assigned to the retail jurisdiction and then among retail customer classes. Pet. Ex. RR, p. 12. It similarly has a significant impact on rate groups and, thus, even if one were to agree with Mr. Phillips that PSI's loads have changed, he did not believe that such a fact would automatically lead to a reallocation of all past investments in production facilities. He observed that a majority of PSI's production facilities were in service during the last PSI retail rate case test period and the 12-CP methodology was utilized in the retail cost of service study underlying the rates approved in that case. He thought it inappropriate now to in effect "reallocate" those facilities in this case." Pet. Ex. RR, pp. 12-13.

(2) Discussion and Findings. We find that PSI's use of the 12-CP methodology to allocate production demand related plant and operating costs is reasonable, based on the testimony of Messrs. Freeman and Brosch. While qualified experts may differ on which methodology is the best fit, based on the evidence presented in this Cause, we cannot conclude that PSI's choice of the 12-CP is unreasonable. We agree with Mr. Freeman that a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where, as here, so much of PSI's plant was in service at the time of its last rate case and costs were assigned using the 12-CP methodology in that case. We find that the results of PSI's jurisdictional separation and retail cost of service studies should be accepted and utilized to allocate operating revenues among customer classes and to design PSI's retail electric rates.

B. Reduction in Subsidy/Excess Revenues.

(1) Evidence. PSI proposed a 33% reduction in the current levels of subsidy/excess revenues between rate groups as its movement towards fully reflecting its cost of service. Mr. Freeman explained that a review of the Company's four major rate groups shows a narrow band of current levels of subsidy/excess revenues. Further, Mr. Freeman testified that the Company's current retail cost of service study shows that the Company's current rates are substantially within the reasonable bounds of cost-based rates. Pet. Ex. Z, p. 29, and Pet Ex. RR, pp. 8-10.

Mr. Brosch recommended that PSI's rate class RS be "assigned no more than the overall percentage increase in total retail revenues ultimately ordered by the Commission." Pub. Ex. No. 2, pp. 108-109. Mr. Freeman concluded that Mr. Brosch's approach would decrease revenues from Rate RS by approximately \$6.5 million if the Company's rate request were approved in this case, which then would have to be allocated to other customer groups. *Id.* Mr. Freeman pointed out that such a shifting of cost responsibilities would negate the Company's proposed 33% reduction in inter-class subsidies, and move RS away from producing a return at virtually the system average rate of return, to a rate below the system average, as shown on Pet. Ex. RR-2, p. 2, and Pet. Ex. RR, p. 10.

(2) Discussion and Findings. We do not accept Mr. Brosch's invitation to ignore existing subsidies disclosed by Mr. Freeman's cost of service study in this case. We find that the 33% reduction in those subsidies is appropriate and should be ordered. This will be a significant step in achieving equity among rate classes, and it is consistent with past orders of this Commission on this subject. The rates as approved herein shall produce substantially the revenue shown in the columns under Column L in Pet. Ex. Z-13, filed as part of PSI's October 15, 2003 workpapers.

9. Rate Design.

A Cost and Revenue Adjustment Mechanisms. The Petitioner proposed three mechanisms to track costs and revenues that it contends are substantial, variable and largely outside of its control. They include a Summer Reliability Tracker (proposed new Standard Contract Rider 70); a NO_x Emission Allowance rate adjustment mechanism (initially proposed new Standard Contract Rider 69); and, a Midwest ISO-Related rate adjustment mechanism (proposed new Standard Contract Rider 68). PSI also proposed minor changes to its existing fuel adjustment ("Rider 60") and SO₂ emission allowance (Rider 63) tracking mechanisms, which were unopposed. We approve each of these cost and revenue tracking mechanisms as discussed below.

(1) Petitioner's Proposed Summer Reliability Tracker.

(a) Background. Mr. Esamann explained that, since 1999, PSI has had to make substantial forward reliability power purchases for the summer months to maintain adequate reserves to meet anticipated customer peak load requirements. Pet. Ex. B, p. 41.

Because of these substantial purchased power needs, in 1999 PSI petitioned this Commission for approval of a purchased power cost tracking mechanism. This Commission initially approved PSI's purchased power tracking mechanism (PSI Standard Contract Rider 67) on a limited basis in Cause No. 41448. *Id.* at 42. In our April 2001 Order in Cause No. 41448-S1, this Commission approved the extension of that mechanism through 2002. In March 2002, in Cause No. 42200, PSI petitioned this Commission and requested the indefinite extension of its purchased power tracker. Alternatively, PSI requested that this Commission extend PSI's purchased power tracker for a 2-year period in Cause No. 42200, and ultimately resolve the design of PSI's tracker in this rate case. *Id.* at 43-44. In our June 2003 Order in Cause No. 42200, we approved the extension of PSI's purchased power tracker through 2004, and determined that the ultimate resolution of the future use of the tracker would be made in this rate case.

PSI implemented its PowerShare[®] program in 2000, in the wake of the Midwest capacity shortage and the resulting 1998 and 1999 wholesale power market price spikes. *Id.* at 44. PowerShare[®] CallOption creates demand reductions through customer commitments to reduce load during times of system peak. Customers are compensated for this commitment to reduce demand in two ways: (1) an option premium payment, which gives PSI the right to call for load reductions within certain parameters, and (2) an energy payment based on actual load reductions. The payments are provided in the form of customer bill credits. *Id.* Mr. Esamann said that although no contractual load reduction commitments are provided under PSI's QuoteOption, the latter is also capable of reducing demand, through appropriate pricing signals to its customers. *Id.* at 45. Under the QuoteOption, customers are compensated by means of energy credits when they choose to reduce load in response to these price signals. *Id.*

With respect to off-system sales, Mr. Esamann testified that in Cause No. 40003, \$6 million of off-system sales profits were built into PSI's base rates. Accordingly, in each year since 1996, PSI retail customers have received the benefit of this annual \$6 million credit through rates.

(b) Petitioner's Proposal. PSI's proposed Summer Reliability Tracker consists of the three components discussed immediately above – purchased power costs, PowerShare[®] costs, and off-system sales profits. With regard to the purchased power component, PSI proposed that the tracker apply to PSI's actual purchased power costs (demand components only) for forward reliability purchases (*e.g.*, monthly or weekly forward purchases) made for the summer months of June through September in order to maintain an adequate PSI reserve margin (15% to 17%). These forward reliability purchased power costs would be eligible for recovery via the tracker, subject to PSI's demonstration to the Commission that its purchase decisions were reasonable at the time made. The energy components of such purchase costs would be eligible for recovery via PSI's fuel adjustment charge tracker. Pet. Ex. B, at p. 46. Under PSI's proposal, no level of purchased power costs would be reflected in PSI's base rates. Pet. Ex. CC, pp. 1-9.

With regard to the PowerShare[®] component of the Summer Reliability Tracker, PSI proposed that the tracker allow recovery of PSI's actual June through September PowerShare[®]

CallOption and QuoteOption costs above (or below) the \$1,023,000 test period level to be included in base rates. Mr. Bailey testified that the test year contains \$1,023,000 of expenditures in the form of bill credits related to PSI's PowerShare® CallOption program, and that even with PSI's proposed transition of this program to more traditional DSM pricing, PSI believes that program expenditures will be at or above this level. Pet. Ex. AA, p. 14; Pet. Ex. CC, pp. 1-9.

With regard to the off-system sales profits component of the Summer Reliability Tracker, PSI initially proposed to flow back to customers 100% of PSI's actual June through September off-system sales profits, plus 25% of actual PSI off-system sales profits earned in the non-summer months (October through May). In response to other parties' concerns, in rebuttal PSI modified this sharing proposal to a 50%/50% sharing of off-system sales profits achieved on a year-round basis. In the early years of the tracker's existence, PSI believes that this feature could result in the net impact of the tracker being a credit, rather than a charge, to customers. Pet. Ex. B, p. 47. Pet. Ex. CC, pp. 1-9.

Similar to the process that has been utilized for its current purchased power tracking mechanism (PSI Standard Contract Rider 67), PSI proposed on an annual basis, in the spring, to present to the Commission its June through September forward purchased power and PowerShare® arrangements. After the close of that summer period, PSI would present the Commission with its actual June through September purchased power, PowerShare®, CallOption and QuoteOption costs, as well as its annual off-system sales profits. After the Commission has completed its review, the net impact (credit or charge) of these June through September costs, along with 50% of PSI's annual off-system sales profits, would be passed through to retail customers via the Summer Reliability Tracker. *Id.* Pet. Ex. CC. p. 8.

Under PSI's proposal, the Summer Reliability Tracker credit or charge will be allocated to all firm retail customers based on their contribution to the summer peak demand, and the credit or charge would be refunded or collected over a 12-month period. Non-firm or interruptible customer loads would not be allocated any of the costs or credits related to the Tracker. The credit or charge would be reconciled to actual at the end of the 12-month cycle to ensure that only the approved credit or charge was ultimately refunded or collected through the Tracker. Pet. Ex. CC, pp. 3-4; Pet. Ex. CC-1.

In connection with its Summer Reliability Tracker proposal, PSI requested corresponding accounting relief, specifically, authority to defer for subsequent recovery or credit, its June through September purchased power and PowerShare® costs, and its off-system sales profits. Pet. Ex. CC, p. 9.

(c) Rationale for PSI's Proposal. Mr. Esamann indicated that he believes that a continuation of a purchased power tracking mechanism, such as that incorporated into PSI's proposed Summer Reliability Tracker, is desirable. The continuing volatility of the wholesale power market; PSI's increasing need for purchased power to maintain an adequate reserve margin; the positive credit quality implications of such a mechanism; and, sound regulatory policy reasons support having such a tracker in place. Pet. Ex. B, at 49. Mr. Esamann testified that the wholesale power market continues to present the potential for high prices, volatility and

price spikes. As recently as March 2003, he related, wholesale market prices spiked to \$135 per MWH. *Id.* at 50. He pointed out that almost 130,000 MWs of power plant projects have been cancelled since the beginning of 2000, with the majority of those cancellations occurring in the Eastern Interconnect region. As projects are cancelled and demand grows, demand will catch up or overtake supply, leading to increasing prices, he predicted. *Id.* at 51. Mr. Esamann concluded that he cannot envision a Midwest wholesale power market that, for many years into the future, does not have some price spikes. *Id.* at 52. According to Mr. Esamann, the question is not whether there will be price spikes, but how frequently and how high they will be. For this reason, PSI believes that it is far more appropriate to address its purchased power costs via a tracker mechanism, rather than attempt to build a representative level into base rates.

Mr. Esamann next turned to the issue of PSI's continuing need for purchased power. He emphasized that PSI customers' demand for electricity continues to grow. Mr. Esamann testified that, even during this period of economic downturn, the PSI system experienced a new peak record demand in the Summer of 2002, after experiencing a 3.6% increase in peak in 2001. *Id.* He explained that even with the addition of the Noblesville Repowering Project (representing approximately 200 additional MWs) and the Madison and Henry County Generating Stations (approximately 663 MWs combined), PSI's projected planning reserve margins for 2003 and beyond, without forward reliability purchases, are well below PSI's 15% minimum reserve margin. PSI's projected reserve margins range from just below 11% in 2003, down to 8.3% in 2006, and 11.4% in 2010 -- a deficit of several hundred megawatts in almost every year for the next eight years. *Id.* at 53. Thus, he said, PSI will need to continue to purchase several hundred megawatts of forward power to satisfy its reserve margin needs for the next several summers. By 2006, he said, PSI's purchased power needs will rise to almost 450 MWs. *Id.*

Mr. Esamann also addressed the positive credit quality implications associated with the purchased power tracking component of the Summer Reliability Tracker. He observed that Commission approval of PSI's continued use of a purchased power tracking mechanism will give investors and credit rating agencies assurance that PSI will have an opportunity to recover the majority of its purchased power costs incurred to provide reliable service to customers, and this assurance should assist PSI in attracting necessary capital at reasonable costs. *Id.* at 55. Maintenance of credit quality is important both for utilities and their customers, he observed. *Id.* at 56. Reduced credit quality results in higher debt costs that, in turn, will result in higher rates charged to customers in the future. *Id.*

Mr. Fetter underscored the credit quality implications associated with tracking and recovery of purchased power costs. According to Mr. Fetter, the financial community relies on the presence of fuel and purchased power adjustment mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. These mechanisms mitigate a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into a utility's credit profile as a negative element. Pet. Ex. H, pp. 25-26.

Mr. Fetter noted that Standard & Poor's stated in November 2002 its opinion concerning the importance of electric utilities having the opportunity to recover fuel and purchased power expenses:

When assessing the importance of productive regulation to the credit strength of an electric utility, something to consider is the means by which the utility can expect to recover variable expenses, particularly fuel and purchased-power expenses, which have highly erratic unit costs. Recent, and in some cases, extreme volatility in the U.S. wholesale electricity markets, as well as in the natural gas markets, underscores this importance. It is no coincidence that utilities with stronger fuel and power cost recovery mechanisms typically enjoy loftier credit ratings.

Pet. Ex. H, at pp. 26-27.

Mr. Esamann offered a number of regulatory policy rationales in favor of the use of purchased power tracking mechanisms. For example, a utility should have a reasonable opportunity to recover the prudently incurred costs associated with meeting its obligation to provide adequate and reliable service to its customers. Moreover, a basic principle of ratemaking is that reasonable costs of providing utility service should be reflected in the prices charged for that service. In Mr. Esamann's opinion, consistent with these principles, tracking mechanisms are appropriate regulatory tools for reflecting costs that are volatile, substantial, and largely outside of the utility's control. Mr. Esamann noted that another way to encourage cost-effective supply decisions is to set up regulatory mechanisms that encourage the utility to plan in advance and to hedge against spot market price volatility and availability risk. PSI believes strongly that encouraging advance planning and hedging strategies will align customer and shareholder interests in achieving reliable and cost-effective electric utility service.

As to the PowerShare[®] component of the Summer Reliability Tracker, Mr. Esamann noted that PSI's PowerShare[®] program impacts are analogous to purchased power and, as such, should be treated the same as purchased power for ratemaking purposes. In PSI's experience, PowerShare[®] costs tend to be highly variable from year to year, and thus lend themselves to tracking treatment. Having a tracker, and assurance of cost recovery for prudent PowerShare[®] costs, will also provide PSI with an incentive to maximize the use of the PowerShare[®] program. Pet. Ex. B, at p. 57.

With regard to the off-system sales profit component of the Summer Reliability Tracker, Mr. Esamann testified as to why he believes that tracking, rather than base rate treatment of such revenues is appropriate, and why an explicit incentive sharing mechanism should be included. Because off-system sales profit can be variable, unpredictable, and largely outside of the utility's control, Mr. Esamann explained that it makes sense to use a tracking mechanism for such credits to customers, rather than building an ongoing level into rates. Pet. Ex. B, pp. 57-58. He noted that off-system sales profits will vary widely from year to year, depending upon a number of

factors such as wholesale market conditions, the performance of PSI's generating system, and PSI native load customer demand and energy requirements.

As for the 50/50 incentive sharing proposal, Mr. Esamann testified that allowing PSI the opportunity to earn and retain a portion of off-system sale profits will encourage PSI to maximize off-system sales opportunities. In Mr. Esamann's view, such a sharing aligns customer and shareholder interests in maximizing off-system profits for the benefit of all stakeholders. Mr. Fetter shared this view, emphasizing that such activities, which are outside the sphere of PSI's traditional regulated operations, deserve to be encouraged with the benefits being shared by both customers and shareholders. Pet. Ex. B, pp. 61-62. Mr. Esamann testified that PSI takes on potential costs and risks whenever it transacts business in the wholesale market and without the opportunity to retain a portion of off-system sales profits, a rational utility would work to ensure that its native load customer demands are met, but would not necessarily take on the potential incremental costs and risks necessary to maximize the use of its generation in the off-system sales market. Pet. Ex. B, pp. 58-61.

Finally, Mr. Esamann testified that off-system sales represent one area where a utility can work to actually earn a return that approximates the net operating income authorized by the Commission in the utility's rate order. Allowing PSI to retain a portion of off-system sales profits achieved will give PSI a more realistic opportunity to earn its authorized return, while still remaining subject to the fuel adjustment charge statute's earnings test. Pet. Ex. B, pp. 60-61. Mr. Esamann concluded that PSI's proposed Summer Reliability Tracker is designed with symmetry and balance, with appropriate consideration to risk and reward. Customers will pay for PSI's costs of forward reliability purchases and PowerShare® costs for the summer months (subject to PSI's demonstrating the reasonableness of its forward purchases), while throughout the year customers will receive the benefits of off-system sales profits generated from PSI generation. Pet. Ex. B, p. 59.

(d) Positions of OUCC, Intervenors, and Testimonial Staff. The OUCC opposed the totality of PSI's proposed Summer Reliability Tracker, while other Intervenors opposed certain aspects of the proposal. The OUCC took the position that tracking treatment was neither necessary nor desirable for PSI's purchased power costs, for PSI's PowerShare® costs, or for PSI's off-system profits. Rather, the OUCC proposed that a test period base level of such costs and revenues be built into PSI's base rates in this case, with no tracking mechanisms for fluctuations between those base levels and actual levels experienced by PSI in the future. Additionally, the OUCC opposed the Summer Reliability Tracker's explicit sharing mechanism for off-system sales profits. Pub. Ex. No. 2, p. 28.

OUCC witness Brosch testified that tracking treatment is not necessary for several reasons. First, he argued that tracking is no longer necessary because PSI has recently added capacity to its system, thus reducing its purchased power needs, and because wholesale market prices have moderated since PSI's purchased power tracker was first approved in 2000. He also argued that revenues from load growth should be sufficient to compensate PSI for any increased purchased power expense it experiences going forward. Pub. Ex. No. 2, pp. 32-33. OUCC witness Endris added his view that "a request to track a cost [of purchased power] that represents

only 1% of the test year fuel expense is insubstantial and undeserving of tracker treatment." Pub. Ex. No. 6, p. 8. Instead of tracking treatment, the OUCC argued for base rate treatment of PSI's purchased power costs, based on PSI's actual Summer 2003 purchased power costs (approximately \$2 million). As for PSI's PowerShare® costs, OUCC witness Endris took the position that "The CallOption program expense is similarly negligible compared to total fuel expenses. ..." Pub. Ex. 6, p. 8.

OUCC witnesses Brosch and Endris also testified on the off-system sales component of PSI's proposed Summer Reliability Tracker. Mr. Brosch opposed tracking off-system profits and recommended building in a base level instead. He offered his opinion that the test period level of off-system profits achieved by PSI of approximately \$18.7 million appeared to be representative of an ongoing level of such profits and even possibly conservative since the test period level did not include the availability of new generation added by PSI (Madison, Henry County, and Noblesville Repowering). Pub. Ex. No. 2, pp. 41-43. In further support of the OUCC's position that PSI's off-system sales should be addressed through base rates rather than through a tracking mechanism, Mr. Endris testified that in his opinion PSI native load customers likely would not receive as much benefit through the Company's proposed off-system sales profit sharing mechanism as they would get through continued traditional ratemaking treatment that includes actual test year results in setting rates. Pub. Ex. No. 6, p. 5.

With respect to PSI's proposed sharing of off-system sales profits, Mr. Brosch testified that PSI needs no special incentive to make off-system sales. In his view, the better answer would be an approach where there is no tracking, whereby the Company would have the opportunity to retain for shareholders 100% of any incremental profits earned on such sales between rate cases. Public's Ex. No. 2, p. 43. Mr. Brosch also noted that, since the 2002 implementation of the Joint Generation Dispatch Agreement, PSI's off-system sales have generally been limited to system energy transfers of surplus hourly energy to CG&E, which in Mr. Brosch's view insulates PSI from market and profitability risks. Finally, Mr. Brosch stated his opinion that there is simply no shareholder entitlement to additional returns, since shareholders are not "at risk" for plant production costs. Pub. Ex. No. 2, p. 44.

Mr. Endris also testified that PSI does not need any further incentives to maximize profits from off-system sales. Pub. Ex. No. 6, pp. 16-19. PSI has engaged in off-system sales activity in every year subsequent to the Commission's order in Cause No. 40003, without any special treatment tracking off-system sales. One can only conclude based upon actual results that the current traditional method, with 100 percent retention of all changes in profits, provides adequate incentive to PSI to engage in reasonable off-system sales effort. Pub. Ex. No. 6, p. 23. Mr. Endris also claimed that the dollars, volumes, and types of sales to be included in the proposed sharing mechanism are difficult to reconcile with actual historical results. *Id.* at 9. This kind of confusion, he maintained, should lead the Commission to reject PSI's proposal and instead determine that test period off-system sales profits of \$18.7 million, or some other reasonable *pro forma* projection, should be reflected as a credit to revenue requirements." *Id.* at 16.

Mr. Endris was also concerned that the transaction documentation and analysis involved in determining off-system sales profits is voluminous, complex and contentious and will lead to

frequent and difficult litigation. Pub. Ex. No. 6, p. 26. He believed the required audits would be costly and resource-intensive, which costs, he suspected, would be borne by the ratepayers, either as a drain on the very profits to be shared or as an expense hitting the FAC earnings test. *Id.* at 26-27. He concluded, as Mr. Brosch did, that PSI should "receive traditional ratemaking treatment of appropriate off-system sales profits as a reduction to revenue requirements and let PSI retain 100% of profits thereafter." Pub. Ex. No. 6, p. 32. Such treatment, he contended, would provide PSI "its desired incentive to maximize the use of the PSI generating resources to achieve off-system sales margins while not subjecting ratepayers to this insufficiently-supported sharing mechanism." *Id.*

The OUCC's alternative was to propose that a base amount of expected purchased power costs and off-system sales profits, such as the \$2 million of Summer 2003 purchased power costs and the \$18.7 million of test period off-system sales profits, be included in base rates, and that PSI shareholders and customers share in costs and profits above or below this amount, with 90% going to PSI's customers and 10% to its shareholders, on an annual basis. This alternative approach, the OUCC claimed, would properly credit customers for the burden of capacity costs included in base rates, as well as incentivize PSI to economically maximize the pursuit of both purchased power and off-system sales profits. Pub. Ex. No. 1, p. 37; Pub. Ex. No. 2, p. 61.

Intervenor PSI-IG was supportive of the continuation of PSI's purchased power tracker, but opposed tracking PowerShare[®] costs above or below the level included in base rates. PSI-IG Ex. No. 1, p. 25. As for the off-system profits component of the Summer Reliability Tracker, Mr. Phillips took the position that customers should be credited with the profits from off-system sales in PSI's base rates, because PSI is allowed to earn a return on all of its generating stations. *Id.* Mr. Phillips also testified that eliminating any off-set for off-system sales from base rates shifts all of the risk to the customers and provides PSI with no incentive to make such sales. He said that to the extent PSI earns more from off-system sales than the amount included in its base rates, the profits should be shared with its customers through a tracking mechanism separate from the Summer Reliability Tracker. Mr. Phillips recommended that this Commission approve only the minimum recovery of purchased power costs in the tracking mechanism without the PowerShare[®] credits or other provisions PSI has requested. *Id.* at 26.

Intervenor Kroger took issue only with the off-system profits component of the Summer Reliability Tracker, and specifically the incentive sharing mechanism. Kroger witness Kevin C. Higgins testified that, assets that are being used to make these profits possible are being fully funded by ratepayers -- and ratepayers should receive a significant share of any benefit. The Company's share should be limited to the amount needed to provide it with adequate incentive to make profitable off-system sales transactions. He proposed that the \$18.7 million in profits from off-system sales during the test period be credited against base rates for the rate-effective period and on either side of this \$18.7 million there should be a reasonably-sized deadband. Mr. Higgins proposed that as long as the annual amount of off-system sales profit remained within the deadband, no further rate adjustments would be made. In the event that profits from off-system sales fall below or rise above the deadband, he recommended that some sharing of incremental benefits or decremental shortfall take place, implemented through a tariff rider. Mr. Higgins proposed a 50/50 sharing of incremental benefits or decremental shortfall outside the

deadband and a deadband of + or -\$3 million. This approach, Mr. Higgins claimed, fully aligns the interests of shareholders and ratepayers, and provides the Company with ample incentive to make profitable off-system sales. Kroger Ex. No. 1, pp. 6-8.

Intervenor CAC opposed certain aspects of the Summer Reliability Tracker. CAC witness Bruce E. Biewald contended that the proposed tracker will reduce or eliminate the incentive for the Company to manage costs and risks associated with the tracked costs. Mr. Biewald also predicted a net cost to customers from the proposed Summer Reliability Tracker beginning in 2004, and he claimed that the system for accounting and tracking of transactions is complex and prone to abuse. More specifically, Mr. Biewald recommended that this Commission disallow the Summer Reliability Tracker's off-system sales profit sharing mechanism and require the Company to credit all such profits to customers. Mr. Biewald recommended that this Commission approve a modified version of the Summer Reliability Tracker that allows customers to retain 100 percent of off-system sales profits in all months of the year. Modifying the tracker in this manner, he claimed, would greatly increase the probability that customers would indeed receive a net credit from the tracker. CAC Ex. B, pp. 4-5, and 20.

Testifying on behalf of the Commission's Testimonial Staff, Dr. Borum and Ms. Cvengros indicated that they were generally supportive of PSI's proposed Summer Reliability Tracker. Ms. Cvengros observed that, while somewhat unwieldy as packaged together as a single tracker, the components of the Summer Reliability Tracker are all well-defined elements. IURC Staff Ex. No. 2, p. 28. Both Dr. Borum and Ms. Cvengros agreed that tracking treatment for PSI's summer purchased power costs was appropriate, so long as the tracker procedures called for upfront Commission scrutiny and approval of PSI's purchased power decisions, and as long as the tracker included a mitigation credit feature, whereby customers can be credited with profits derived from off-system sales made from the purchased power capacity. The Testimonial Staff believes that PSI's proposed Summer Reliability Tracker contains these essential elements and is an acceptable purchased power tracking mechanism. IURC Staff Ex. No. 2, p. 31.

On the subject of purchased power cost tracking, Dr. Borum characterized the costs to be tracked as largely outside of the control of management. In Dr. Borum's view, purchased power is a primary example of such uncontrollable costs. Dr. Borum opined that the use of trackers "reduces regulatory lag, and thus limits the utility's incentive to keep costs low." However, he observed, continuation of a pre-approval process for forward power purchases is necessary to meet PSI's summer reliability requirements and continuation of the pre-approval regulatory process connected with the Summer Reliability Tracker will reduce financial uncertainty and risks for PSI, in return for an up-front review and input by interested groups in the resource planning and acquisition processes implemented by PSI. Staff, he said, believes that treating forward purchases similar to the regulatory treatment of building additional generation capacity will promote a resource portfolio planning process in which forward purchases are appropriately considered. Additionally, Staff witness Cvengros noted that, while PSI's purchased power needs in the near term may be relatively small when compared to previous years, PSI's growing customer load will require increasing quantities of purchased power at about the time an order would be expected in this Cause. As a consequence, denying PSI's proposed Summer Reliability

Tracker on the grounds that PSI does not currently have to make substantial purchases would probably require the Company to file another petition for a purchased power tracker shortly after an order is issued in this Cause. IURC Staff Ex. No. 3, pp. 5, 13, 17, IURC Staff Ex. No. 2, p. 28.

With regard to the PowerShare[®] component of PSI's Summer Reliability Tracker, Ms. Cvengros opined that the PowerShare[®] costs above or below the amount to be included in PSI's base rates are not likely to be excessive and PSI would not suffer a financial hardship were they to be excluded from the Tracker. On the other hand, she explained that Staff views the PowerShare[®] program as being analogous to a purchased power option contract, whereby the Company pays an upfront demand premium in exchange for the right to have access to power when needed at specified prices. The only difference is that PowerShare[®] provides curtailable power, instead of deliverable power – but both have the same effect in maintaining an adequate reserve margin during peak periods. In sum, Staff believes the PowerShare[®] program costs are legitimate expenses that should be recovered by the Company, and the Summer Reliability Tracker provides an acceptable, but not the only, method of recovering such costs. IURC Staff Ex. No. 2, pp. 28 and 29.

With regard to the off-system profits component of the Summer Reliability Tracker, Staff witness Cvengros explained that Staff views the off-system sales profit sharing component as an expansion of the mitigation credit that has been employed in connection with PSI's existing purchased power tracker. In Ms. Cvengros' view, PSI's sharing proposal explicitly addresses a sharing of off-system sales profits, in contrast to the implicit sharing that occurs today with a base level of off-system profits included in rates. Staff believes that an explicit sharing mechanism provides a better incentive to the utility to make economically efficient off-system sales, as well as easier review and monitoring of the shared profits. IURC Staff Ex. No. 2, p. 28.

While not opposed to PSI's proposed off-system sales sharing mechanism, Ms. Cvengros did offer some alternatives for the Commission's consideration. For example, if the Commission believes that the proposed 50%/50% sharing of off-system profits is inadequate, Ms. Cvengros noted that an adjustment of the shared portion of profits between 50%/50% and 80%/20% to customers' favor would be reasonable, and should not cause a financial hardship on the Company. Alternatively, Ms. Cvengros noted that the Commission could include a base amount of off-system sales in PSI's rates, with or without some sharing of profits above that base amount. Based on PSI's estimate of its test period off-system profits without an explicit sharing mechanism, Ms. Cvengros recommended \$13 million as an appropriate base amount of off-system profits to be included in rates should the Commission prefer that approach. IURC Staff Ex. No. 2, p. 31, Attachment K.

In response to other parties' criticisms concerning the complexity of identifying off-system sales profits for purposes of sharing, Ms. Cvengros agreed that the process is complex, but noted that the process for determining off-system profits is the same process necessary for determining fuel costs for the FAC. Dr. Borum concurred on this point, explaining that the JGDA dictates how off-system sales costs and revenues must be allocated between PSI and its affiliate, CG&E. IURC Staff Ex. No. 1, pp. 26-33; IURC Staff Ex. No. 2, p. 27.

(e) PSI Rebuttal. Mr. Esamann testified that PSI continues to believe that cost tracking mechanisms are appropriate for costs that are substantial, variable or volatile, and largely outside of the control of management. Just as important, he said, PSI continues to believe that cost tracking mechanisms benefit both customers and the company in numerous ways -- by allowing the utility to recover its prudently-incurred costs of providing service, no more and no less; by helping to level the playing field between competing options (capital versus expense options), thus encouraging the most economic choices; by eliminating artificial disincentives to pursuing the most economic choices (again, capital versus expense options, or forward versus spot market choices); by encouraging advance planning and hedging as opposed to reliance on volatile spot markets, thus aligning customer and company interests in reliability and price certainty; and by allowing the utility to defer the need for repeated general rate cases. Pet. Ex. DD, p. 17.

He maintained that PSI's purchased power and PowerShare[®] costs are collectively significant, variable, and largely outside of its control -- similar to fuel costs. Tracking treatment, he said, assures that the utility will recover these costs of providing service on a timely basis, no more and no less, while base rate treatment, alone, of these cost items would inevitably result in an over or under recovery. Pet. Ex. DD, pp. 17-18.

He emphasized that tracking treatment goes a long way toward leveling the playing field between capital and expense options -- maintaining that a utility can mitigate its purchased power and peak load management risks by building additional "iron-in-the-ground" capacity, and if the reserve margin is large enough, the utility can virtually eliminate the need for any reliance on purchased power or peak load management programs. But, he said, a total long-term reliance on on-system generation may not be the most economic option for the utility's customers. A purchased power and PowerShare[®] tracking mechanism gives the utility the flexibility to rely on the power market when appropriate and encourages the utility to make the most economic choice, by allowing the utility an opportunity to recover its out-of-pocket purchased power and peak load management costs. Pet. Ex. DD, pp. 17-18.

Mr. Esamann criticized the OUCC's proposed level of purchased power expense to be reflected in PSI's base rates as an alternative to PSI's proposal. He observed that the Company's 2003 purchased power costs were by far the lowest level of forward reliability purchased power costs experienced by PSI since prior to 1999 (less than \$2 million). *Id.* at 18-19. Moreover, he said, this low level of purchased power expense is likely to be temporary, given the expected gradual increase in wholesale power prices and the approximately 100 MWs of annual demand growth PSI is experiencing on its retail system. *Id.* at 19. Accordingly, he said, if this Commission were to include a base amount in PSI's rates, he would recommend that this Commission use an average of the last two years' forward reliability purchased power costs, which amounts to \$10.5 million. That level, he noted, is still lower than PSI's estimated annual purchased power costs over the next few years. *Id.*

To the OUCC's argument that tracking treatment is not necessary for off-system sales profits and, instead, off-system sales profits of \$18 million should be included in base rates, Mr.

Esamann pointed to the variability associated with off-system sales profits -- a variability that is in large part outside of PSI's control and dependent, instead, on market prices, weather and customer demands. He added that the test period level of \$18 million in off-system sales profits experienced by PSI was by far the highest level of off-system sales profits earned by PSI from 1996 through the test period. However, he said, if the Commission decides to include a level of off-system sales profits in base rates, PSI believes that a reasonable level of trading expenses should also be included in PSI's base rates. In its case-in-chief PSI excluded certain of its trading expenses from its rate increase request, essentially in exchange for an explicit off-system sales sharing mechanism. Pet. Ex. DD, pp. 19-20.

With respect to the OUCC's contention that PSI needs no special incentive to make off-system sales, Mr. Esamann testified that PSI continues to believe that incentivizing it to maximize off-system sales profits through a sharing mechanism makes sense for both customers and the Company. In Mr. Esamann's view, an incentive sharing mechanism will increase the overall size of the "pie" (the off-system sales profits), with benefits created for both customers and the Company. Pet. Ex. DD, pp. 20-21. Mr. Esamann observed that although it is easy to say that a utility should always seek to maximize off-system sales profits for the benefit of native load customers, it is important to keep in mind that there are costs and risks associated with maximizing such sales profits. If the utility has no upside opportunity, there will naturally be a disincentive for the utility to incur those incremental costs and risks. Pet. Ex. DD, p. 21.

He emphasized that there are incremental costs and risks associated with having and keeping the Company's generation available for off-system sales opportunities, even when it is not anticipated to be needed for native load customers' demand requirements. There are, he said, different levels of costs that are incurred to serve anticipated native load customer demands, versus serving anticipated native load customer demands plus anticipated off-system sales opportunities. Such costs include costs associated with committing, ramping up, and dispatching the units -- and different levels of these costs will be incurred to serve anticipated native load customer demands, versus serving anticipated native load customer demands plus anticipated off-system sales opportunities. There are also costs associated with maintaining and repairing the utility's power production facilities that may not need to be incurred for native load customers purposes. If PSI concluded that sufficient off-system sales opportunities were available, and if PSI were incented to get that unit back on-line and running in order to capitalize on wholesale market opportunities, PSI would likely incur such extraordinary O&M costs, he said. Pet. Ex. DD, pp. 21-22.

Mr. Esamann went on to explain why there is likely to be a difference in the level of off-system sales achieved with and without an incentive sharing mechanism, observing that if PSI lacked a meaningful incentive opportunity in this area, PSI would likely commit its system differently than it does today. It would of course continue economic dispatch, but would commit its units to meet anticipated native load requirements, rather than to meet native load requirements plus wholesale market opportunities. In any given hour, he said, PSI may have surplus energy available to sell into the wholesale market, depending on actual native load demands versus the level of demand anticipated the day-before. Nevertheless, he estimated that

this difference in unit commitment would result in a decrease in off-system sales profits on the order of magnitude of \$4 million annually. Pet. Ex. DD, p. 23.

Moreover, Mr. Esamann emphasized that there are other benefits to native load customers associated with having PSI's generating units committed to meet native load demands plus wholesale market opportunities. If native load demands should exceed expectations, or if PSI experiences a generating unit outage, the "market-committed" generation can instantaneously be used to meet native load customer demands, because that generation is already ramped up and running and native load customers have "first call" on PSI generation. Under the alternative, "native load only" commitment scenario, however, native load customer demands would need to be partially met through potentially higher cost hourly market purchases until such time as incremental PSI generation could be ramped up and committed. Pet. Ex. DD, pp. 22-24.

(f) Commission Discussion and Findings. Pursuant to IC 8-1-2-42(a), this Commission has the legal authority to approve tracking mechanisms for fluctuating costs. As a general rule, IC 8-1-2-42(a) states that: "A public, municipally owned, or cooperatively owned utility may not file a request for a general increase in its basic rates and charges within fifteen (15) months after the filing date of its most recent request for a general increase in its basic rates and charges..." *Id.* However, this section goes on to indicate that: "The phrase 'general increase in basic rates and charges' does not include changes in rates related solely to the cost of fuel or to the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by the commission." Ind. Code § 8-1-2-42(a). The proposition that the Commission has the authority to approve the tracking of certain costs has also been affirmed by the courts. *See, City of Evansville v. SIGECO*, 339 N.E.2d 562, 593 (Ind. Ct. App. 1975); *L.S. Ayres v. Indianapolis Power & Light Co.*, 351 N.E.2d 814, 838-39 (Ind. Ct. App. 1976).

Against this legal and regulatory backdrop, we will now consider the evidence regarding tracking treatment of PSI's purchased power and PowerShare[®] costs. The evidence in this case establishes that the wholesale market continues to exhibit the potential for volatility, that it is reasonable to consider PSI's purchased power and PowerShare[®] costs collectively given their analogous functions, and that PSI's collective purchased power and PowerShare[®] costs are potentially significant. Moreover, the evidence indicates that even with the addition of incremental generating capacity in 2003, PSI continues to have a need for purchased power in order to maintain an adequate reserve margin, and that PSI's retail load continues to grow. While PSI's Summer 2003 purchased power costs were relatively low, the evidence suggests that PSI's purchased power needs and costs are likely to increase over time given PSI's load growth and expected wholesale market price increases and volatility.

Importantly, as we concluded in both our April 2001 Order in Cause No. 41448-S1 and our June 2003 Order in Cause No. 42200, a number of regulatory policy rationales support the continued use of purchased power tracking mechanisms. A utility should have a reasonable opportunity to recover prudently incurred costs associated with meeting its obligation to provide adequate and reliable service to its customers. Additionally, credit quality is of importance to both utilities and their customers, and there is a recognized connection between the periodic

review and adjustment of rates and positive credit quality. Last, but not least, a purchased power tracking mechanism is consistent with our goal of leveling the playing field among resource options and thereby encouraging pursuit of the most cost-effective options. We concluded in 2001 and 2003, and we conclude today, that continuation of a purchased power tracker mechanism for PSI will align the mutual interests of PSI's customers and shareholders in reliable and cost-effective electric utility service.

Notably, these same regulatory policy rationales support approval of tracking treatment for PSI's PowerShare® costs, albeit to varying degrees. We believe that approval of the PowerShare® component of the Summer Reliability Tracker will allow the recovery of prudently incurred costs associated with providing reliable electric service, and will provide PSI with an incentive to maximize the usefulness of its PowerShare® program. In sum, the law, the evidence, and regulatory policy all support approval of a tracking mechanism for PSI's purchased power and PowerShare® costs. Accordingly, we hereby approve the purchased power and PowerShare® components of PSI's proposed Summer Reliability Tracker. We also approve PSI's corresponding accounting request for authority to defer for subsequent recovery via the Tracker, its June through September purchased power and PowerShare® costs.

With respect to the off-system sales profit component of the Summer Reliability Tracker, the Commission recognizes that a number of options were presented to us for consideration by the various parties. In undertaking our review of this issue, the Commission recognizes that fair and reasonable asset optimization programs, that present corresponding benefits to ratepayers, should be encouraged. While the utilization of ratepayer funded resources in the pursuit of off-system sales profits should result in a corresponding reward to ratepayers for the risk being borne, the Commission is cognizant that PSI should have an appropriate incentive to optimize its generation assets. The Commission believes that balancing the interests of PSI and its ratepayers is appropriate and, if done properly, will provide a benefit that might not otherwise be possible.

In the present case, PSI achieved \$18.7 million of such profits during the test period and a significantly larger amount during calendar year 2002. Yet, Mr. Esamann testified that PSI projects *losses* in the area of off-system profits for both 2003 and 2004. We agree with PSI that off-system sales revenues are potentially significant, volatile or variable, and largely outside the control of the utility and may therefore be tracked. In reaching this conclusion we find that tracking off-system sales profits does not appear to be overly complicated and administratively burdensome. As Ms. Cvengros and Dr. Borum both pointed out, the same information that will be necessary to track off-system sales profits is already captured and analyzed in connection with PSI's fuel adjustment charge proceedings.

While we are granting approval to track off system sales profits, we do not believe that the 50%/50% sharing proposal put forth by PSI presents the optimum approach to addressing this issue. In presenting several options for our consideration, we note that Ms. Cvengros indicated that the Commission could include a base amount of off-system sales in PSI's rates, with or without some sharing of profits above that base amount. This approach was also recommended by the OUCC, Kroger, and PSI-IG. We are persuaded by the recommendation that we include a

level of off-system sales profits in base rates and find that this should be done in conjunction with the use of a 50/50 sharing mechanism.

In adopting this approach, we are cognizant of PSI's concern that the amount included should reflect a reasonable level of trading expenses which were not included in the explicit sharing proposal advocated by PSI in this Cause. While we are persuaded by the OUCC's proposal that we include \$18.7 million in rates for this purpose, this amount does not reflect trading expenses. Therefore, consistent with our earlier findings, we find that \$18.7 million of test-period off-system sales profits, minus \$3,953,000 for trading expenses, for a net value of \$14.747 million, should be included in base rates to reflect the test-period. We further find that off-system sales profits should be tracked from this amount and shared 50/50 between PSI and ratepayers. We also find that tracking should be above and below the net amount in base rates; PSI may not apply a net annual off-system sales profit of less than zero to the tracker; and, all off-system sales net income should be included as jurisdictional income for purposes of the FAC earnings test. In addition, PSI's corresponding request for accounting relief is also approved.

(2) NO_x Emission Allowance Tracker.

(a) PSI's Testimony. PSI witness Farmer testified that Petitioner's proposed NO_x emission allowance rider provides a rate mechanism for the recovery of charges to operating expense resulting from PSI's use of NO_x emission allowances ("EA") in order to comply with the federal and state NO_x SIP Call requirements. He explained that beginning in May 2004, PSI will be required to substantially reduce the amount of NO_x emitted from its power plants. Emission allowances will be consumed for each ton of NO_x emitted into the atmosphere during the months of May through September. Even though PSI will receive various allocations of zero cost NO_x emission allowances from the Indiana Department of Environmental Management ("IDEM"), PSI's future NO_x SIP Call compliance strategy includes the possibility of purchasing or selling NO_x emission allowances in order to minimize the cost of compliance to retail customers. PSI's proposed Standard Contract Rider No. 69 would allow for cost recovery of NO_x emission allowances as such allowances are consumed. Pet. Ex. CC, p. 10.

Mr. Farmer explained that the concepts incorporated within the Company's proposed NO_x Emission Allowance Adjustment are similar to the concepts embodied within its SO₂ Emission Allowance Adjustment, approved by the Commission in Cause Nos. 39584 and 39584-S2. Both riders, he said, are "zero based" riders, meaning that there are no costs being recovered in base rates. Both riders provide for the recovery of costs of emission allowances consumed due to the operation of the Company's own generating units used to serve native load customers, as well as the cost of emission allowances included in the cost of power purchased or transferred for economy, reliability, or operating purposes, to the extent such costs are specifically identified or can be reasonably estimated. Costs under both riders are allocated to retail customers based on kilowatt-hour sales. According to Mr. Farmer, both riders provide for the recovery or crediting of net gains and losses from the sale of emission allowances that have been allocated to the Company by the environmental agencies or emission allowances purchased by the Company on behalf of native load customers. Pet. Ex. CC, p. 11.

PSI initially proposed that Standard Contract Rider No. 69 provide for the sharing of net gains and losses associated with NO_x EA sales at a ratio of 80% to customers and 20% to the Company. However, in response to concerns raised by other parties, in rebuttal PSI modified its NO_x emission allowance cost tracking proposal in two ways: First, PSI changed its initial proposal to provide customers with 100% of net emission allowance sales proceeds; and second, PSI proposed to incorporate the NO_x emission allowance tracking features into PSI's existing SO₂ emission allowance rate adjustment mechanism (Standard Contract Rider No. 63). Pet. Ex. CC, pp. 10-22; Pet. Ex. QQ, p. 42.

(b) OUCC's, Intervenor's, and Testimonial Staff's Testimony. The OUCC's only objections to the proposed NO_x emission allowance tracker involved the 80%/20% sharing feature, and the use of a mechanism separate and apart from PSI's existing SO₂ mechanism. As mentioned above, PSI addressed both of these concerns in its rebuttal testimony.

Intervenor PSI-IG took the position that PSI should propose this tracker, if appropriate, if and when the costs are of significant magnitude to warrant another adjustment to customers' bills. Alternatively, PSI-IG was of the opinion that the NO_x emission allowance tracker should be treated the same as PSI's SO₂ allowance cost tracker (i.e., 100% of net sales proceeds should be credited to customers). PSI-IG Ex. No. 1, p. 27.

Testimonial Staff generally supported approval of rate adjustment mechanisms for the recovery of SO₂ and NO_x emission allowance costs incurred providing service to jurisdictional retail customers. Dr. Borum testified that Staff has no objection to the costs of NO_x emission allowances being passed to ratepayers through a tracker similar to the one being proposed by PSI for SO₂ allowances, but had concerns regarding the proposed 80/20 sharing between the Company and ratepayers of gains or losses from selling NO_x emission allowances. Staff recommended that the NO_x tracker be consistent with the SO₂ tracker, with all gains or losses from sales of the emission allowances going to ratepayers, rather than an 80/20 split. IURC Staff Ex. No. 3, p. 26.

(c) Commission Discussion and Findings. With PSI's rebuttal modifications to its NO_x emission allowance tracking proposal, there appears to be very little dispute among the parties on this topic. We conclude that it is reasonable to authorize PSI to track and recover NO_x emission allowance costs incurred in connection with providing retail electric service, and to authorize PSI to credit customers with 100% of net proceeds associated with any sales of jurisdictional NO_x emission allowances. Accordingly, we approve PSI's NO_x emission allowance proposal as modified in its rebuttal testimony.

(3) Midwest ISO-Related Cost and Revenue Adjustment Mechanism.

(a) PSI's Testimony. PSI also requested approval of a new Midwest ISO Management Cost And Revenue Adjustment Standard Contract Rider ("Midwest ISO Rider") to track, for recovery or credit, changes in the amount of PSI's Midwest ISO Management Costs and Revenues included in base rates as a result of this proceeding. PSI is proposing to track (i) costs billed to PSI by the Midwest ISO under Schedule 10 (ISO Cost Recovery Adder), or a

successor provision (including Schedule 10-FERC), of the Midwest OATT, or any successor Tariff for the Midwest ISO; (ii) costs billed to PSI by the Midwest ISO under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or a successor provision, of the Midwest OATT, or any successor Tariff for the Midwest ISO; (iii) costs billed to PSI by the Midwest ISO under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder), or a successor provision, of the Midwest ISO OATT, or any successor Tariff for the Midwest ISO; (iv) costs billed to PSI by the Midwest ISO for standard market design or other government mandated transmission costs PSI is required to pay on behalf of its Indiana retail electric customers; and (v) certain Midwest ISO transmission revenues assigned to PSI by the Midwest ISO. Pet. Ex. Z, pp. 30-31; and Pet. Ex. RR, pp. 13-14.

PSI proposed to include in its base retail rates \$5.554 million for Schedule 10 costs. As there are no current charges billed under Schedules 16 and 17, such Schedule 10 costs are the only costs that PSI proposed to include in base retail rates. PSI also proposed to include in the fixing of base rates Midwest ISO transmission revenues of \$10.905 million as a revenue credit, thus reducing base retail rates. The net of these two items resulted in a reduction in PSI's proposed base rates of \$5.351 million. Pet. Ex. Z, p. 31.

Mr. Freeman said that under the Midwest ISO Rider, the total of these cost categories would be added together and the transmission revenues subtracted to determine the net amount for each quarter. The difference between this net amount and \$1.337 million (one quarter of \$5.351 million) would be recovered or credited, whichever is applicable, to the customers through the Midwest ISO Rider. Mr. Freeman said that the annual retail electric jurisdictional costs to be incurred by PSI under Midwest ISO Schedules 16 and 17 are estimated to be approximately \$2.1 million. Consistent with PSI's Fuel Cost Charge Standard Contract Rider and PSI's Emission Allowance Charge Standard Contract Rider, PSI proposed to adjust the Midwest ISO Rider on a quarterly basis. To the extent that any costs to be recovered under the Midwest ISO Rider are not billed by the Midwest ISO to PSI pursuant to Midwest ISO Schedules 10, 16 or 17, PSI will demonstrate in its quarterly filing the amount and reasonableness of such costs. Pet. Ex. Z, pp. 31-33.

PSI witness Ronald R. Jackups emphasized that the proposed Rider addresses costs and revenues that are variable, substantial, and outside the control of PSI, but which result from PSI taking transmission service under the Midwest ISO OATT to serve PSI's retail electric customers. More specifically, Mr. Jackups explained that the costs and revenues covered by the proposed Rider are: (1) the result of the decisions of the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI (i.e., dependent upon the actions of the FERC, the Midwest ISO, customers and loads, etc.). Further, as federally set and imposed charges at retail, necessary in order to provide retail service, Mr. Jackups testified that the costs to be incurred are just, reasonable and necessary. Pet. Ex. M, pp. 46-48.

(b) OUCC, Intervenors', and Testimonial Staff's Testimony. The OUCC opposed PSI's proposed Midwest ISO Rider because such costs failed to meet the five (5) rate tracking criteria recommended by OUCC -- including its view that PSI's Midwest ISO's costs

are relatively stable and insignificant in the context of PSI's overall O&M expenses (only 0.678%, before tax). Although Mr. Carver's testimony specifically addressed the \$5.761 million of MISO Schedule 10 costs, the MISO charges are still immaterial even after considering the additional \$2.1 million estimated by PSI witness Freeman (Pet. Ex. Z, pp. 31-33) attributable to MISO Schedules 16 and 17. In lieu of PSI's proposed Midwest ISO rider, OUC would alternatively recommend the continuation of the deferral mechanism previously authorized by the Commission -- to the extent PSI does not separately recover any increased administrative costs through increased transmission revenues, MISO related efficiencies or through retail base rates. Pub. Ex. No. 1, pp. 57-59.

Intervenor PSI-IG opposed the tracking of Midwest ISO-related costs above or below the amount to be included in base rates, and opposed PSI's proposed Midwest ISO Rider as premature and probably inappropriate. PSI-IG witness Phillips said that PSI can request approval of this mechanism, if appropriate, when all matters regarding the MISO, costs, operations, rules and regulations are known. PSI-IG Ex. No. 1, p. 26.

Testimonial Staff endorsed PSI's proposed tracking of Midwest ISO related costs and revenues, including costs that are (1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI. Dr. Borum testified that, Staff agrees that these MISO-related revenues and MISO-related costs are appropriately recovered through a tracker, in that "PSI's proposal is balanced . . . designed to flow through to ratepayers MISO-related transmission revenues received by PSI . . ." Dr. Borum noted that PSI has very little control over these costs or revenues since they are incurred through MISO tariffs and schedules approved by the FERC. Staff Ex. No. 3, pp. 23-24.

(c) PSI Rebuttal Testimony. In rebuttal, PSI witness Freeman testified that the Midwest ISO Rider: (1) is not limited to just PSI's Schedule 10 costs; (2) covers costs that PSI is currently incurring and revenues that PSI is currently receiving; and (3) covers costs and revenues that have shown a significant variance (for example, an eight-month variance of over \$10 million in transmission revenues). Pet. Ex. RR, pp. 5-7.

(d) Commission Discussion and Findings. We find reasonable PSI's proposal to track Midwest ISO related costs and revenues, including costs that are: (1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI. PSI's proposal is balanced and designed to flow through to customers Midwest ISO-related transmission revenues received by PSI. Therefore, we find that PSI's proposal to track Midwest ISO related costs should be approved.

(4) Modifications to PSI's Existing SO₂ Emission Allowance Tracker. Separate and apart from its rebuttal proposal to incorporate NO_x emission allowances into its existing SO₂ emission allowance tracker (Rider 63), PSI also proposed a minor modification of its current Rider 63 SO₂ Emission Allowance Adjustment (originally approved in IURC Cause No. 40003). The purpose of this minor modification is to conform to the manner in which costs applicable to

native load customers are captured today. Mr. Farmer explained that this proposed conforming modification does not involve any substantive changes. The primary reason for the modification, he said, is the fact that the Company has various processes in place that are used to specifically identify emission allowance costs applicable to native load customers. Pet. Ex. CC, pp. 12-13.

No party objected to PSI's proposed modification to its SO₂ emission allowance tracking provisions, and as mentioned above, IURC Testimonial Staff supported continuation of SO₂ tracker. Accordingly, we accept PSI's proposed modifications and approve PSI's proposed modified Standard Contract Rider No. 63.

(5) Modifications to PSI's Existing Fuel Adjustment Charge Mechanism. PSI also proposed minor modifications to its existing fuel adjustment charge mechanism, Standard Contract Rider No. 60. Mr. Farmer explained that, since PSI's last retail rate case, there have been several significant proceedings relating to the fuel adjustment charge, such as this Commission's generic FAC case, Cause No. 41363, and cases interpreting the generic FAC case, such as SIGECO's and NIPSCO's FAC45 cases, and PSI's FAC56 case. PSI simply proposed to update Rider 60 to reflect current practices. Pet. Ex. CC, pp. 13-14. No party objected to these minor proposed changes to PSI's Rider 60. We find such changes to be appropriate in light of our various FAC orders issued since PSI's last rate case, and we hereby approve PSI's proposed modifications to its Standard Contract Rider 60.

B. Real Time Pricing ("RTP").

(1) PSI Proposal. PSI proposed to terminate its RTP program (Standard Contract Rider No. 21), which consists of a two-part rate – an access charge for the customer's historic load ("CBL"), which is billed at standard tariff rates, and an energy charge for the customer's incremental or decremental energy usage that is billed at a real time price. Currently, 57 PSI customers participate in RTP, with an expected peak load reduction of about 15 MWs. Pet. Ex. AA, p. 15.

PSI witness Jeffrey R. Bailey testified that PSI began its RTP Program in 1996. Its primary objectives were to elicit load responses by customers in response to changes in price. To that end, it was reasoned that customers would reduce load during high priced periods and thereby produce demand savings to PSI. Similarly, customers could shift load to, or grow their load during, lower priced periods, creating demand savings or incremental revenue growth. *Id.* at 16. The Company's analysis, after more than seven years of experience, however, revealed that, on average, RTP customers were receiving a nearly 40% discount from tariffed rates for the RTP portion of their bills (*i.e.*, load above the CBL). For some customers the discount was even higher. Absent any modification of the RTP Program, this subsidy by PSI's other industrial and commercial customers would continue, Mr. Bailey observed. *Id.* As a result, he said, PSI has concluded that it and its other industrial and commercial customers were not receiving a proportionate amount of value from these RTP customers relative to other demand response programs. PSI's conclusion was to eliminate its RTP Program, effective with a final order in this Cause. *Id.*

Mr. Bailey testified that while the Company's analysis confirmed that *some* customers do respond to high prices, about two-thirds of the customers on the RTP program were only minimally responsive or not responsive at all. *Id.* at 17. Over the last couple of years, he said, market prices have been very low. Because the RTP commodity price is the lesser of the market price or PSI's marginal generation costs, PSI's low generation costs, combined with low market prices, has meant that customers have generally received low price signals and have not had an incentive to shift their load to lower priced, off peak periods. *Id.* So, he observed, while customers are receiving a big discount from tariff rates, PSI is not receiving the proportionate value created when customers shift load to off-peak periods. In essence, he said, the program is not cost-effective. *Id.*

Mr. Bailey said that PSI had investigated various potential ways to modify the program, including putting "fixed adders" on the commodity portion of the price and demand charges on the T&D portion of the price to improve cost recovery from the RTP customers, but that ultimately the Company determined that these actions were drastic enough to impact RTP customers nearly as much as termination of the program, altogether. Even after such changes, he observed the Company could not be certain the pricing mechanism would function satisfactorily. *Id.*

He added that the credits for load reductions under PowerShare[®] were far less than the discounts generated under RTP. *Id.* The Company concluded that a more appropriate valuation (*i.e.* credit or discount commensurate with value created) would be achieved through PowerShare[®], either through its CallOption or QuoteOption components. *Id.* Additionally, he said, PowerShare[®] has other features that make it preferable to the RTP program, including greater certainty in the amount of peak load reduction (customers contract to reduce a certain amount under CallOption). *Id.* In contrast, the Company under RTP must rely on the customer to reduce load voluntarily in response to price signals, with no upfront estimate of the load reduction the customer may be able to produce. *Id.*

As for the impact of termination of the program on customers, Mr. Bailey testified that, on average, customers will experience bill increases of about 8% before the increase requested in this cause. *Id.* at pp. 8-9. He added that a small number of customers will see bill increases exceeding 20% before the rate increase requested. *Id.* Recognizing that this is a potential hardship for customers, the Company proposed to phase-out the RTP program over a two-year period. *Id.*, p. 20-21. The Company calculated the benefits received by customers under the RTP program relative to its base tariff and proposed to offer these benefits as credits on each RTP customer's electric bill during the phase out period. The initial credits, he said, would be based on 67% of the savings from the base tariff – as defined during the test period – at the time new tariffs are approved (Phase I), and would be reduced to 33% at the end of the first year (Phase II). At the conclusion of the second year, the credits would cease (Phase III). Pet Ex. BB, p. 9.

PSI proposes that its Rate LLF and HLF customers that are not on the RTP program provide a subsidy necessary to fund the bill credits during the two-year phase out period.

Accordingly, PSI would file three consecutive sets of tariffs for Rates LLF and HLF – Phase I, Phase II, and Phase III. The amounts of the subsidies required would be as follows:

RTP Credits			
	Total	Phase I	Phase II
Applicable to HLF	\$7,492,263	\$5,019,816	\$2,472,447
Applicable to LLF	\$ 187,694	\$ 125,755	\$ 61,939
Total	\$7,679,957	\$5,145,571	\$2,534,386

Id. at 9-10.

The Company proposed to transition RTP customers that do have the capability of curtailing usage to its PowerShare® program, and they would be eligible for the program even while they are getting bill credits from the RTP program phase-out. Pet Ex. AA, p. 21. Mr. Bailey observed that the Company's Time-Of-Use rate is another option that may be a good fit for some RTP customers.

Mr. Bailey added that there may be some customers who can create additional value by the nature of operations they adopt, citing as an example a customer that can consistently reduce its load during peak hours, which may create value for PSI that is in excess of the PowerShare® CallOption premiums. For these customers, he said, the Company will entertain a special contract, subject to Commission approval. *Id.*

(2) PSI-IG Position. The PSI-IG opposed elimination of the RTP rate. It argued that the rate is theoretically sound and accurately sets forth hourly rates based on PSI's hourly costs. PSI-IG Ex. No. 1, p. 21. To PSI's point that RTP customers do not adequately shed load at the time of PSI's summer peak, witness Phillips argued that the RTP rate should not be discontinued for that reason, arguing that their rate is not an interruptible rate, but a rate that charges customers an accurate price for each hour of the year. *Id.* He added that the customer has the option of paying an extremely high price during high cost hours or reducing purchases based on operational and economical considerations and that PSI should not be allowed to eliminate this rate because it does not agree with the choice made by its customers. *Id.* at 21-22.

Mr. Phillips argued that the current RTP has a 10% adder to hourly costs for HLF and a 25% adder to hourly costs for Rate LLF, which, he said, means that PSI always recovers actual hourly costs, plus a 10% to 25% adder to those actual hourly costs. So, he said, it is impossible for PSI to lose money with respect to the cost to serve its RTP customers. *Id.* at 22. He concluded that the elimination of this rate structure would be viewed as a backward step for providing customers with accurate price signals and an economic choice. *Id.*

(3) Kroger Position. Kroger disagreed with PSI's proposal to have rates HLF and LLF customers fund a subsidy to former RTP customers migrating to those rate schedules. Kroger witness Higgins observed "the irony of this situation is that the purpose of the subsidy is to shield the RTP customers from the immediate pain of paying these very same HLF and LLF

rates; so the customers who are already on these 'painful' rates are asked to pay even more, in order to 'ease the pain' of the RTP customers that are now joining them." Kroger Ex. No. 1, p. 22. Accordingly, Mr. Higgins recommended that PSI's subsidy proposal be denied, arguing that if Rates HLF and LLF are found to be just and reasonable, then there is no compelling reason to shield RTP customers from the pain of being on these rates. *Id.* at 23. Alternatively, he argued that if the RTP subsidy is adopted, it should be funded, 50% by PSI and 50% by all customer classes, in proportion to each class's base revenue requirement. *Id.*

(4) Testimonial Staff's Testimony. Staff witness Dr. Borum stated that the Testimonial Staff is not convinced that the RTP program should be terminated, rather than continued or modified. IURC Staff Ex. No. 3, p. 35. The problems cited by PSI, he maintained, are essentially financial. *Id.* He said that wholesale market prices have been low for the past few years and as PSI's on-system incremental costs are also low, RTP customers have not shifted load in response. *Id.* Thus, he observed, if PSI is getting no value from load shifting, putting these customers on regular tariffs allows the Company to collect more revenues. *Id.* In essence, he said, PSI wants to terminate the program because it is not receiving enough financial benefit in today's low price environment. PSI's financial concerns do not mean that the RTP program has no value, he argued. *Id.*

Dr. Borum said that he is convinced that retail prices that are designed to better reflect actual hourly wholesale market costs will benefit both customers and utility companies. Over time, he argued, customers shifting loads in response to these hourly wholesale market costs would benefit both the RTP program participants and the utility with lower overall costs. Thus, Staff believes PSI has put undue emphasis on immediate results and under-valued the likelihood of significant effectiveness of the RTP program over time. *Id.*

Dr. Borum noted that this Commission, in approving a previous version of PSI's purchased power tracker, directed PSI to explore all possible methods and resources of providing efficient and economical energy to its customers, including "innovative rate options." *Id.* at 35-36. As a result, he said, Staff recommended that "approval of the purchased power tracker be conditioned on PSI entering into a collaborative process with Staff and other interested groups to not only explore whether and how the RTP program should be modified, but to actively evaluate the feasibility of implementing other innovative rate options." *Id.* at 36.

(5) PSI Rebuttal. PSI's witness Bailey testified in response to Mr. Phillip's claim that the Company's proposals on the RTP and PowerShare[®] Programs would be reviewed as a backward step for providing customers with accurate price signals and an economic choice. He said that the Company's proposal to eliminate the RTP rider and transition its customers to special contracts or to the newly enhanced PowerShare[®] program would constitute an appropriate course to maximize the value of its peak load management program. Pet Ex. SS, p.2.

Responding to Mr. Borum, Mr. Bailey testified that PSI's track record shows continued experimentation with innovative rate and demand-side management options, and demonstrates that the Company is committed to the goal of reducing the need for additional generating capacity. He said that the Company is certainly willing to discuss with Staff and interested

parties real time pricing and other innovative rate options for the future. However, he believes that the current RTP program is so flawed that the only feasible option is termination. There is no clear solution, he said, to improve price signals from a market that currently does not adequately reflect the long-term cost of capacity. *Id.* at 3.

Regarding the contention that PSI's request to terminate the RTP is largely motivated by short-term financial concerns, Mr. Bailey responded that PSI's revenue requirement is derived completely independently of any of its optional rate programs, and would remain the same if the RTP program is retained or terminated. *Id.* PSI's direction, he said, is not motivated by financial self-interest, but rather by the fact that the program is not cost effective. *Id.* He added that retention of the program would cause other customers to bear the burden of a program that produces no tangible value for them. *Id.*

As to Mr. Phillip's complaint that PSI appears to be driven by some notion of revenue neutrality in its RTP proposal, Mr. Bailey responded that PSI *is* driven by the notion of revenue neutrality, pointing out that one only needs to read the RTP rider (Standard Contract Rider No. 21) to see that the design of the RTP program was to make customers "bill neutral" with respect to their historical usage. *Id.* Customers could then respond to real time prices accordingly, he said. *Id.* With respect to Mr. Phillip's contention that because PSI charges an adder to hourly costs, it is impossible for PSI to lose money with respect to the cost to serve its RTP customers, Mr. Bailey responded that even if PSI recovers the incremental costs of generation (*e.g.*, fuel), there is not sufficient remaining margin to support the cost of additional capacity that RTP customers are using. *Id.* at 5.

To Dr. Borum's contention that by eliminating the RTP Program PSI is no longer reducing the disconnect between wholesale and fixed retail prices and Mr. Phillips' opinion that the RTP is theoretically sound and accurately sets forth hourly rates, Mr. Bailey responded that a major point in the Company's case-in-chief is that the price signals being sent to RTP customers are *not* accurate. *Id.* He explained that the RTP pricing mechanism sends a price signal to customers based on the lesser of PSI's internal generation cost or the market. Whatever the signal attempted to be sent from wholesale prices, he said, is negated by a mechanism that allows the customer to always receive the lowest price of generation or market. *Id.* Mr. Bailey testified that the fact that the RTP program is voluntary, not mandatory, substantially influences the long-term cost effectiveness of the program, as customers have no long-term requirement to remain with the program and subject themselves to the volatility of the wholesale market. *Id.*, at 5-6.

PSI proposes to terminate the program, he said, because it does not produce its intended goal of price response. *Id.* at 7. A prerequisite, he said, to a customer's being placed on the rider was its ability to shift load from higher cost to lower cost pricing periods and to add new load during lower cost pricing periods. If such load shifting is not occurring, and PSI cannot depend on the program for peak load reduction, then the program is not fulfilling its intended purpose, Mr. Bailey testified. *Id.* Other options, he said, like special contracts or PowerShare[®], will save the customer money and produce a benefit to PSI and its remaining customers. *Id.* The Company's position, he said, is that if a customer is going to pay less than tariffed rates, then that customer must bring something of value to the Company, and non-participating customers.

However, under the RTP rider, the discount to participating customers is large while the benefit to the Company and remaining customers is small. *Id.* at 7-8.

Mr. Bailey also disagreed with Mr. Phillips' contentions that a separate cost of service study should be done for RTP customers, observing that RTP is a Rider to Rates HLF and LLF, and the customers on RTP are properly HLF and LLF customers who have chosen to participate in a voluntary rider available to those rates. *Id.* at 8. PSI, he observed, has numerous riders each of which is included with its base rate for cost of service purposes, citing examples PSI's Smart Saver® under Rate RS, Optional Commercial Electric Service under Rate CS, Total Electric Commercial Service under Rate LLF, and Time-of-Use options under both Rates LLF and HLF. *Id.* None of these riders, he pointed out, have ever been fully segregated from its base rate for the development of rates.

Defending the Company's proposed phase-out of the RTP credits to affected customers, Mr. Bailey said that the proposed phase-out, to mitigate the large rate increase the RTP customers will incur if the entirety of their load is immediately placed on Rates HLF or LLF, is something the Company has done in the past, with some success. He cited as an example, Cause No. 40003, where the Company used a three-year phase-in approach to mitigate the bill impacts to Rate MLF customers as that rate was combined with Rate HLF. *Id.* He said that while the Company believes that termination of the RTP program is proper, it also recognizes the hardship it may cause customers because of a large increase in their bill all at one time. A gradualism approach, he observed, is common in the industry and, in the Company's opinion, the right thing to do here. *Id.* at 8-9.

(6) Evidence at Hearing. On cross-examination by PSI at the November hearings in this Cause, Dr. Borum clarified that his testimony was not intended to call for the continuation of the RTP program as is. Rather, he believes that a collaborative process involving interested parties is the best way to examine the future of the RTP program and other innovative rate programs. He also indicated that a goal of any collaborative process concerning innovative rate options should be to increase the cost effectiveness of the rate options. Tr. at R107-R108.

(7) Discussion and Findings. This Commission and its regulated utilities have a responsibility not only to encourage experimental innovative rate options, but also to ensure that programs meet standards of cost effectiveness. Based on the evidence we find that it is apparent that the RTP program, as currently designed, has some serious flaws. No party presented evidence that the program was, in fact, cost effective. However, this Commission believes that innovative rate options such as real time pricing, which encourage customers to react to hourly wholesale market prices, are an important offering.

Consistent with the recommendation of Testimonial Staff, we find that the best venue to deal with the RTP problems would be a collaborative process involving PSI, Staff, and other interested parties. Before this pilot program is discontinued, we feel that the parties should consider ways that it can be redesigned or modified in order to make it an effective program. While the collaborative parties are meeting, the RTP program shall continue in place as is. However, our decision does not prejudice that continuation of the RTP program is necessary or

appropriate. Rather, the goal of the collaborative is to design rate options which will be effective while providing value to PSI, its participating customers, and PSI's non-participating customers (these options may or may not include some form of a real time pricing program). Additionally, we find that the collaborative process should be concluded by October 15, 2004. PSI shall file a report detailing the efforts of the collaborative process by November 15, 2004.

Because PSI has met its burden of proof in regards to the termination of the program *as it is currently designed*, we find that the RTP rider, Rider No. 21 should be extended until January 31, 2005, whereupon it will automatically terminate. However, we would expect that it will be replaced by one or more innovative pricing options developed during the collaborative, or that the majority of PSI's RTP customers will be transitioned to PSI's PowerShare[®] program.

In reaching the foregoing conclusions we also find that phase-out credits proposed by PSI are not necessary or appropriate. While we recognize that in many instances it might be appropriate to phase in the effect of rate changes when certain classes of customers are disproportionately affected by a certain change, we recognize that the very customers we would be seeking to protect through the phase out in this instance have already reaped financial benefits from a program that does not appear to be working as envisioned. As the program will not end until January 31, 2005, and may be replaced by an improved RTP program, current customers will have a sufficient opportunity to prepare for the change. Therefore, we find that phase out credits are not necessary and are hereby denied.

C. PowerShare[®] Program CallOption Pricing Change.

(1) Background. PSI's witness Bailey described PSI's PowerShare[®] program, offered under its Standard Contract Rider No. 23. This program, implemented in January, 2000, is currently a market-based program that provides financial incentives in the form of bill credits to industrial and commercial customers to reduce their electric demand during PSI's peak load times. Customers may choose to participate in either CallOption or QuoteOption.

CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. The strike price is selected by the customer based upon the customer's willingness and ability to comply with the call for load reduction. In return for this commitment to reduce when called, CallOption customers receive a monthly premium payment from PSI as a credit to their bill. In addition, when customers are called to reduce load, they receive an energy credit. PSI's standard CallOption product may be exercised by PSI when the next day's market prices are projected to be greater than the customer's selected strike price. The term of the standard CallOption program agreement is four months – June through September. Pet. Ex. AA, pp. 10-11. Mr. Bailey also described the QuoteOption component of PowerShare[®], which allows a customer to elect whether or not to reduce its load when called upon by PSI when prices reach a minimum price. No monthly premium is paid to QuoteOption customers since they may elect not to respond when called, but an energy credit is paid for load reductions made in response to PSI's calls.

(2) PSI Proposal. Mr. Bailey explained that since inception of the program, PowerShare® has been a market-based program, where the credits provided to customers for load curtailments have been based on the value of those curtailments in the short term wholesale energy market. Because market prices are highly variable, customer credits have varied dramatically from year to year. In 2000 and 2001, customer credits were relatively high and these credits produced excellent customer participation. However, recent low market prices have resulted in low credits for customers that have the ability to curtail load. These low credits have drastically reduced participation in the PowerShare® program, even as PSI has set new peak demand records and has installed additional generating capacity. So, while the PowerShare® program has great potential value to PSI in providing needed capacity, it has been valued less by customers because of the current low market-based credits. *Id.* at 13.

In an effort to reinvigorate the program, and to transition it to a stable program capable of producing consistent capacity value for PSI, the Company proposed to treat PowerShare® CallOption similar to PSI's regulated DSM programs, which are evaluated based upon the long-term avoided costs, rather than on short-term market prices for the summer ahead. In essence, PSI will be giving a long-term capacity value to the CallOption customer's agreement to curtail usage. Under this new pricing methodology, the credits offered to PowerShare® CallOption customers would be based upon the value of avoiding investment in a combustion turbine as opposed to the short-term, highly variable market value. This should, Mr. Bailey said, stabilize the credits PSI can pay customers at an attractive level to customers in exchange for an agreement to reduce their load when called upon. While this would be a material increase over current credit levels, the Company does not anticipate that such credits would exceed half the value of the annual avoided cost of a combustion turbine, he said. *Id.*

Mr. Bailey testified that the test year contains \$1,023,000 of expenditures in the form of bill credits related to PSI's PowerShare® CallOption program, and with the transition of this program to more traditional DSM pricing, PSI believes that program expenditures will be at or above this level. The change in philosophy which results in increased credits to customer should, he said, enhance customer participation levels. *Id.* at 14

(3) Positions of Other Parties and Testimonial Staff. Testimonial Staff expressed disappointment over PSI's proposal to move to a capacity avoidance cost standard for PowerShare® credits. Staff indicated that it is important that utilities find effective ways to provide price signals to end-use customers. The CallOption program was one means of providing price signals to customers who are sophisticated enough to understand and react to those price signals. Staff noted however, that with low market prices, came lower participation and the Commission should not take a negative view of the program when participation fluctuates widely due to the change in premium payments. IURC Staff Ex. No. 2, p.24. PSI-IG witness Mr. Phillips also recommended maintaining the short-term market pricing of CallOption premiums. He testified that using market prices would increase participation when the market prices were high, precisely when such load reduction is most needed. PSI-IG Ex. No. 1, pp. 23-24.

(4) PSI Response. PSI responded that the changes it is proposing to PowerShare® should enhance, rather than detract from the goal of providing price signals that result in changes in customer consumption patterns. Mr. Bailey observed that PSI's proposal merely replaces a short-term, volatile wholesale market price signal with a stable, long-term price signal for the CallOption component of the PowerShare® program. He emphasized that PSI will maintain *short-term wholesale market pricing* through the PowerShare® *QuoteOption* component. This change, he contended, will make PowerShare® an even more effective rate option than the current structure. Pet Ex. AA, p. 10.

(5) Discussion and Findings. We find PSI's PowerShare® proposal reasonable. The CallOption program requires a contractual commitment to reduce load and allows the Company to depend on the load reductions in its Integrated Resource Plan. Under the current proposal, customers would be paid the true value of that reduction. In the current wholesale market, as CallOption is currently structured, it does not appear that customers are getting paid any capacity value. Moreover, the QuoteOption aspect of the PowerShare® program maintains a short term market price based option. Thus, PSI can still benefit when prices are high through higher participation in the QuoteOption program. Therefore we approve the pricing change as proposed by the Company.

D. Line Extension Advance Deposit ("LEAD") Credit.

(1) Evidence. PSI witness Pefley testified in support of PSI's proposed change in its LEAD credit. Ms. Pefley testified that PSI's Standard Contract Rider No. 52, Line Extension – Advance Deposit, is patterned after 170 IAC 4-1-27(C) ("Rule 27") which provides that PSI will require a line extension advance deposit if the estimated cost of extending its facilities to serve a customer exceeds the estimated revenue from the customer over a period of 2 ½ years. Pet. Ex. J, p. 11. Ms. Pefley said that the Company has determined that the application of Rider 52 does not provide for a sufficient amount to allow the Company to earn an adequate return on its line extension costs. She pointed out that while the number of customers has increased by 16% since the end of the test period in the last rate case, PSI's net investment to connect such customers to its system has increased by more than twice this amount, with the result that new customers are not bearing the full costs of connecting to PSI's system. In these circumstances, she said, the unrecovered costs are being passed on to existing customers and results in regulatory lag for PSI between rate cases. PSI proposed to replace the 2½ years of revenue credit in Rider No. 52 with a credit equal to the actual net book value of the plant investment required to connect new customers as of the end of the test period in this proceeding. *Id.* at 13. For the residential class, the credit is a fixed dollar amount per customer. Ms. Pefley maintained that PSI's proposed approach is fair because it reflects the connection costs embedded in the distribution rates that the customer will pay.

OUCG witnesses Endris and Brosch opposed PSI's proposed change to Rider No. 52. Mr. Endris had three concerns with the proposal: (1) in his opinion, PSI has not sufficiently demonstrated that it needs the change; (2) PSI's proposal does not adequately reflect the benefits and contributions of new customers; and (3) PSI's proposal would impede economic growth. Pub. Ex. No. 6, p. 39. Mr. Endris argued that PSI provided no historical analysis demonstrating

that the experience since the last rate case is any different from the past. He said that Ms. Pefley failed to consider that some of the growth in plant investment is for replacement projects due to deterioration or obsolescence. In addition, Mr. Endris indicated that Ms. Pefley failed to show whether some projects contributed disproportionately to the increase in PSI's net plant investment.

Mr. Endris thought that PSI's proposal ignored the prediction of PSI witness Stevie that the 2003-2008 growth rate in kilowatt-hour sales will be greater than the growth rate in peak demand. If this is true, Mr. Endris argued, the new customers will be contributing to fixed cost recovery to a greater extent than their contribution to peak demand capacity requirements. Therefore, he maintained, the capacity cost recovery is likely to contribute to PSI's overall rate of return in a manner that would tend to offset increases in plant investment in the accounts identified by Ms. Pefley. *Id.* at 45.

Mr. Endris went on to testify that the proposed change also upsets the balance of customer and utilities' interests underlying Rule 27. Mr. Endris claimed that if the Commission had intended the line extension rule to result in no increases in rate base, it would not have utilized a revenue basis, but rather something linked to return on investment. Pub. Ex. No. 6, p. 47. Mr. Endris also argued that the Commission's balancing of interests has an impact upon economic development in the form of new housing growth. He said this Commission could have chosen to have the customer pay 100% of the hook-up charges, but instead chose to impose a lesser financial burden. According to Mr. Endris, PSI's proposed change upsets this balancing of interests. *Id.* at 48.

Mr. Brosch asserted that the proposed Rule 27 change ignores the revenues and profits to be contributed by the new customer. Pub. Ex. No. 2, p. 117. He pointed out that a new fixed credit of \$856 would be available for a new residential customer regardless of whether the projected revenue from that customer would justify capital expenditure. He also said the proposed credits do not reflect costs, because the net depreciated cost of plant balances used in Ms. Pefley's calculations are not the values included in the revenue requirements. *Id.* at 118. Finally, Mr. Brosch argued that the investments reflected in the depreciated plant accrual balances were made for different reasons, not just to connect new customers. These balances further include, he said, all prior vintages of construction, rather than the current period costs that might indicate what it actually costs to serve customers today. *Id.* at 119-120.

On rebuttal, Ms. Pefley disagreed with Mr. Endris' concern about PSI's proposal impeding economic development. Ms. Pefley observed that construction costs come in eighth in a list of site selection factors -- behind availability of skilled labor and labor costs. Pet. Ex. LL, p. 2. She also did not believe that the proposed Rider 52 change will significantly impact larger commercial or industrial customers locating in PSI's service territory. Ms. Pefley presented an analysis which showed that using PSI's proposed LEAD credit to several actual connections in PSI's Noblesville service territory, only one large commercial or industrial customer would have been required to pay a deposit in the amount of \$57. *Id.* at 3. With respect to the possible chilling affect on residential development predicted by Mr. Brosch, Ms. Pefley observed that the increase in the cost of a new home under PSI's proposal would be only approximately 0.5% for

the average non-electric space heating customer and 0.9% for the average electric space heating customer.

Ms. Pefley also disagreed with Mr. Brosch's characterization of PSI's proposal as being contrary to sound economic theory. She said that there is no rational economic theory that supports the provision of a credit against distribution construction costs based on fuel cost charge derived revenues that are a dollar-for-dollar pass-through, with no profit margin, as the current rule provides. *Id.* at 4. She observed that Rider 52 as proposed is consistent with the regulatory principle of cost causation, in that it provides a credit to each class of customers based on the distribution-related construction costs reflected in that class's rates. She also stated that Rider 52, if approved, would provide an "apples to apples" standard by crediting constructions costs to connect a customer with construction costs reflected in the rates that the customer will pay. *Id.* at 5. Ms. Pefley also rejected Mr. Endris' claim of a need to perform an analysis of individual work orders, observing that the problem of utility investors and existing customers subsidizing the connection costs of new customers is not new or unique to PSI. *Id.* at 6.

(2) Discussion and Findings. In support of her request in this Cause Ms. Pefley directed our attention to two specific provisions in the rule. The first provision is 170 IAC 4-1-27(C) which states as follows:

Each electric utility shall, upon proper applications for service from overhead and/or underground distribution facilities, provide necessary facilities for rendering adequate service, without charge for such facilities, when the estimated total revenue for a period of two and one half (2½) years to be realized by the electric utility from permanent and continuing customers on such extension is at least equal to the estimated cost of such extension.

170 IAC 4-1-27(C)

Ms. Pefley then indicated that PSI is requesting relief from the Commission under section 170 IAC 4-1-27(H), which states:

This Rule 25 [this section] shall not be construed as prohibiting an electric utility from (1) making extensions without charge where the cost of the same is greater than is provided in (C) above, or (2) providing an alternate plan to be approved by the commission; provided that in the application of this subsection (H) no discrimination is practiced between customers whose service requirements are similar.

170 IAC 4-1-27(H)

Our line extension Rule 27 permits a utility to collect a line extension deposit when the estimated costs to connect a new customer exceed 2½ years of anticipated revenues from the

customer. Thus, a linkage is established between the expected stream of revenues and profits from the customer and the service connection costs required to achieve such revenues and profits. We note that this approach has been applied by Indiana electric utilities for many years.

It is undisputed under Rule 27 that someone must pay for new customer connections and if the new customer does not bring sufficiently compensatory profits to the utility, that new customer must pay a deposit. Alternatively, if a new customer's revenues are expected to be large, the costs to connect and serve the customer will be recovered relatively quickly through regular monthly billings and the new revenue stream, so that no subsidization is caused by new customers. At issue under the Company's new proposal is whether or not a revenue-based framework of evaluation is reasonable, or should be modified in the manner PSI now advocates.

As the modification requested by PSI is properly characterized as a request for variance under 170 IAC 4-1-27(H), the burden of proof is upon PSI to fully support its variance request in order for us to conclude that we may properly deviate from the provisions contained in the rule. We do not have sufficient evidence before us to make such a finding. PSI's proposed changes to Rider 52 reflect a construction credit based upon PSI's construction costs relating to the extension of service, without regard to whether a new customer will generate large streams of revenues and profits or only modest new revenues. The OUCC maintained that the present framework of analysis is valid, and that the Company has not proven otherwise.

We agree with the OUCC on this issue. PSI failed to provide any cost justification for its position. The Company's distribution plant balances include costs of constructing plant for replacement, modernization, highway relocations and reliability enhancement in addition to costs to connect and serve new customers. In order to accurately isolate costs to connect new customers, a special study seems necessary to disaggregate plant costs incurred for this purpose and relate such costs to the profits contributed from new customers. The evidence in this proceeding compels the conclusion that PSI's variance request is not supported by sufficient evidence to allow us to find that we should deviate from the requirements of Rule 27. Therefore, we deny PSI's request to modify the existing LEAD credit mechanism.

E. Optional High Efficiency Residential Service Rate. Mr. Brosch testified that PSI had originally proposed to continue a 20 percent discount under Standard Contract Rider 6.3. Pub. Ex. No. 2, p.111. He said that the discount arose during implementation of PSI's Smart Saver program and was intended as an incentive to promote the installation of high efficiency electric heating and cooling equipment. However, during discovery PSI stated that it appeared that the 20 percent discount would not pass the Utility Cost Test, but that a 10 percent discount would. PSI recommended a reduction of the discount to 15 percent, in order to continue to avoid adverse impact to customers currently on the rate. *Id.* at 111. Mr. Brosch testified that the OUCC supported reducing the Rider 6.3 High Efficiency discount to 15 percent. We find this compromise and proposal of the OUCC and PSI reasonable, and it is approved.

F. Customer Connection Charges. PSI proposed increasing its residential and commercial customer connection charges from \$8.15 to \$9.90. Mr. Brosch objected to these increases, claiming that PSI's current customer connection charges are higher than other Indiana

electric utilities. Pub. Ex. No. 2, p.109. However, in describing the cost support supplied by PSI in support of the proposed connection charges, Mr. Brosch admitted that a customer connection charge as high as \$11.20 could be justified. *Id.* at 110. Mr. Brosch recommended that the charge remain at \$8.15, because this rate recovers a “high percentage” of customer-related fixed costs.

In response to Mr. Brosch’s proposition, Mr. Bailey observed that the fixed connection charge is intended to recover fixed costs and if the charge is not large enough to recover such costs, the part not covered is recovered through variable charges, which penalizes large volume users. This result, according to Mr. Bailey, creates an intra-class subsidy issue not considered by Mr. Brosch. *Id.* at 18. In Mr. Bailey’s opinion, the cost of connection does not vary with usage and should be recovered through fixed charges.

No party disputed that PSI’s proposed connection charge of \$9.90 is cost justified. Nor did any party dispute that connection costs do not vary with usage and should be recovered as a fixed charge. PSI has proposed a gradual increase, which will ultimately lead to the goal of cost causation – having customers who cause costs to be incurred be responsible for those costs. This Commission has repeatedly endorsed this fundamental principle of ratemaking. We find the development of PSI’s proposed residential and commercial connection charge of \$9.90 to be just and reasonable. We authorize PSI to increase the connection charge to Rates RS and CS in the manner described in Mr. Bailey’s testimony (Pet. Ex. BB, pp. 2-3), commensurate with the relief granted herein and it is approved.

G. PSI’s Lighting Tariff Proposals.

(1) Evidence. PSI proposed several changes to its lighting tariffs (Rate SL – schedule for street lighting service, rate AL – schedule for area lighting service, and rate OL – schedule for outdoor security lighting) in order to streamline its offerings of lighting equipment by restricting the number of lighting options provided to customers, and decoupling the capital costs of the lighting systems from the tariff. Mr. Bailey indicated that the number of lighting types and fixtures has grown considerably over the years, and this has made the administration of PSI’s lighting programs more difficult and time consuming. Pet. Ex. BB, p. 11. PSI proposed to freeze certain rate schedules (SL, AL and OL), and transition customers to an Outdoor Lighting Equipment Service (“OLES”) agreement for maintenance and equipment costs, and Rate UOLS – Unmetered Outdoor Lighting Service or Rate MOLS – Metered Outdoor Lighting Service for the energy charges associated with the lighting equipment. *Id.* at 12.

Mr. Bailey explained that customers would benefit from these changes because, the OLES agreement provides a one-on-one equipment contract with the customer where the customer pays the current price of the lighting system. This locks in the customer’s equipment purchase price, eliminates future rate increases, and eliminates subsidies to other lighting customers. Customers will have an option to pay for the lighting system up-front or over time, up to a maximum of ten (10) years. At the end of the equipment contract, the customer will no longer have a monthly payment for the equipment. In contrast, under rates SL, AL, and OL customers pay a monthly fee for the equipment as long as they require electric service. *Id.* Mr. Bailey also recommended eliminating several PSI lighting rates that were frozen.

OUCG witness Mr. Brosch commented that he did not object to PSI's proposals to freeze and phase out rates SL, AL and OL, as long as PSI continues to offer rate OLES at reasonable cost-based rates. Pub. Ex. No. 2, p. 113. Mr. Brosch noted that PSI should clarify its proposal for OLES pricing.

In response to Mr. Brosch's testimony, PSI witness Bailey confirmed that future charges under OLES will continue to be cost based. More specifically, PSI committed to the use of actual cost to acquire and install the lighting systems with appropriate loadings, and will use a rate of return for the computation of levelized fixed charge rates based on the most recent figures approved by the Commission. In brief, the calculations for the recovery of capital related costs will be the same as PSI has used historically in the development of its lighting rates; however, the recovery period will be no longer than ten years, and can be less at the customer's discretion. Additionally, PSI committed that the capital portion of the various lighting rate schedules will not be increased as long as the same lighting system is used by the customer.

(2) Discussion and Findings. PSI's proposed changes to its lighting schedules are hereby approved. Under the new rates, customers will pay cost-based rates for the lighting equipment, and a separate kwh charge for the energy used. No party objected to the streamlining of these tariffs and we find the new proposal to be a more workable and efficient method of offering various lighting services to PSI's customers.

H. General Terms and Conditions for Electric Service. PSI proposed certain minor changes in the General Terms and Conditions for Electric Service contained in its retail electric rate tariff. Pet. Ex. BB-3. No party objected to any of PSI's proposed changes to its General Terms and Conditions. Based on the evidence presented, and the lack of opposition to the proposed changes, we find that PSI's General Terms and Conditions for Electric Service as contained in its proposed retail electric rate tariff are reasonable and should be approved.

I. Undisputed Changes to Tariff. In addition to the changes, deletions and additions to or from PSI's current retail electric rate tariff previously discussed, PSI proposed various other rate schedule changes, deletions and additions which were not disputed in this proceeding. All of such changes, deletions and additions to or from PSI's current retail electric rate tariff that were not disputed are hereby approved, even though they may not be specifically discussed herein.

10. Fuel Cost Adjustment Charge Issues.

A. New Base Cost of Fuel. PSI proposed in this proceeding to increase the base cost of fuel to be used in its fuel cost adjustment charge proceedings from 14.112 mills per kWh to 14.484 mills per kWh. Pet. Ex. X, pp. 34-35. No party challenged such proposal. We find that such proposal is reasonable and proper and should be approved. When PSI files its new schedule of rates and charges as ordered below, PSI should file with the Electricity Division of this Commission a new base cost of fuel as approved by this Finding, and a new fuel cost charge as

approved on the date of approval of the new rates and charges, modified to reflect the new base cost of fuel.

B. Authorized Net Operating Income for Fuel Cost Adjustment Charge Purposes. For purposes of the earnings test contained in the fuel cost adjustment charge statute, and consistent with our return findings in this Order, PSI shall be authorized to earn \$267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, not taken into account in this case as of the August 31, 2003 update of Petitioner's plant for rate base purposes. The Commission also finds that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

C. OUCC Recommendation to Restate PSI's Books and Records for FAC Earnings Test Purposes. Mr. Brosch recommended that the Commission recognize that the FAC earnings test is vulnerable to serious distortions due to accounting reclassifications and what Mr. Brosch termed as abusive levels of selective rate tracking and excessive cost deferrals. Pub. Ex. No. 1, pp. 20-23 and 127. In fact, Mr. Brosch asserted that the FAC earnings tests cannot be relied on to backstop inappropriate regulatory policies or the approval of piecemeal rate trackers and accounting deferrals. Mr. Brosch took particular exception to the Company's accounting for mark-to-market valuation adjustments recorded by the Company pursuant to Financial Accounting Standards Board Statements Nos. 133 and 138. Mr. Brosch explained that from late 1997 through November 2001, the Company recorded unrealized gains and losses relating to the market value of certain trading positions above-the-line. Mr. Brosch quoted from Mr. Farmer's prefiled testimony wherein Mr. Farmer stated that PSI began recording mark-to-market gains and losses below-the-line in December 2001 in response to an accounting directive from the Chief Accountant of FERC that was received in August 2001. *Id.* at 122. The effect of this accounting change was that such revaluations would not thereafter be included in reported utility operating income.

Mr. Brosch objected to the inconsistency between the accounting policy before and after the FERC directive. He proposed that this Commission should direct PSI to restate its books for purposes of the FAC earnings test, to reflect the application of either an above-the-line or below-the-line classification of mark-to-market gains and losses across all relevant reporting periods. Mr. Brosch sponsored an attachment to his testimony (MLB-3) which purported to show that if mark-to-market gains and losses had been excluded from jurisdictional above-the-line income, PSI's cumulative earnings differential through the relevant period in PSI's FAC58 would have shown a cumulative earnings excess of \$58.3 million rather than the cumulative earnings deficit of \$6.6 million reported by PSI.

PSI witness Farmer urged this Commission to reject the OUCC's invitation to retroactively restate its FAC earnings test results due to the fact that the FERC now directs utilities to account for mark-to-market gains and losses below-the-line. He observed that, with one exception related to the accounting for PSI's Marble Hill related costs, which by order of the

Indiana Supreme Court were directed to be excluded from ratemaking processes, the FAC earnings test has always been calculated by reference to a utility's actual books and records. Pet. Ex. QQ, p. 44. Mr. Farmer testified that PSI has faithfully calculated its earnings test results by reference to its actual books and records, complying with FERC-mandated accounting requirements, including the directive to record mark-to-market gains and losses below-the-line, beginning in 2001. *Id.* It was Mr. Farmer's view that the Indiana custom and practice of following actual books and records should not be changed retroactively to produce a different result from that shown by the Company's books and records.

D. Discussion and Findings on this Issue. We are mindful of the fact that accounting principles represent a dynamic rather than a static set of rules, and that changes in accounting principles are typically applied on a prospective as opposed to a retroactive basis. We also recognize that there will likely be many such changes in the future. An important principle of regulation is that a utility maintain its books and records in accordance with generally accepted accounting principles and orders of the bodies that regulate the utility. There is no suggestion here that PSI has done anything other than act in accordance with this principle. We do not believe it would be good policy to require a utility to restate its income in a way that does not reflect its actual books. For the reasons stated above, we reject the OUCC's recommendation that PSI adjust and retroactively restate its books for FAC earnings test purposes.

II. Purdue University Issues.

A. Evidence. Intervenor Purdue University ("Purdue") witnesses, Mr. Van Meter and Ms. Haase suggest Rider 67 - and its successor Rider 70 - should not be applied to Purdue because it is unfair for Purdue to pay costs to meet PSI's peak demand when Purdue has self generation that can meet Purdue's peak load requirement. Purdue has a special contract with PSI. Ms. Haase also complains that PSI failed to update the proportionate contribution to peak demand, noting that Purdue installed significant self generation after entering into its contract with PSI. Purdue Ex. No. 2, pp. 8-9. For this reason, Ms. Haase recommends that PSI update its load calculations when costs are updated. *Id.* at 11. Additionally, Mr. Van Meter complains generally about the volatility that trackers provide in Purdue's bill. He noted that trackers make up more than 10 percent of Purdue's bill to PSI, and cause great fluctuation in Purdue's bill, making it difficult to budget. Purdue Ex. No. 1, pp. 9-10.

In response, PSI witness Bailey stated that whatever load Purdue places on PSI's system during peak load conditions contributes to PSI's peak. In addition, in accordance with operating criteria, PSI must carry spinning and supplemental reserves associated with whatever Purdue load it is experiencing. The stability and predictability of Purdue's load is immaterial to this process. Pet. Ex. SS, pp. 12-13. Therefore, PSI must carry, and plan for, sufficient reserves attributable to meeting the load that Purdue imposes on PSI's system.

Mr. Bailey explains that Ms. Haase's contention, that PSI has failed to update the proportionate contribution to peak demand, is simply incorrect. As the lead negotiator of the Purdue contract, Mr. Bailey noted that PSI recognized that Purdue's load would change as a result of their additional generation. In the development of the allocators in Cause No. 40003,

PSI made a *pro forma* adjustment to reflect the amount of load Purdue expected to take from PSI following the addition of its new generating equipment. *Id.* at 13. In response to Ms. Haase's contention that PSI should update its load calculation when costs are updated, Mr. Bailey explained that while the loads of Purdue are readily ascertainable, the class loads for PSI's major rate schedules are not. Allocators for PSI's major rate schedules are derived through load research and require an extensive study. Mr. Bailey comments that it is not practical or cost effective to update them outside the context of a rate case. *Id.*

In response to Mr. Van Meter's concern about the volatility that rate tracking mechanisms produce for Purdue, PSI indicated that it understands the concern, but that Purdue probably has more certainty in its electric bill than any other PSI customer, due to its special contract. Mr. Bailey noted that Purdue's electric bill from PSI was only 0.78% of its budget for 2002-2003. *Id.* at 14.

At the evidentiary hearing Purdue entered into three stipulations, namely: (1) Purdue places load on PSI's system during PSI peak load conditions; (2) PSI must carry and plan for reserves attributable to meeting all of its anticipated load, including the load associated with Purdue's contract; and (3) there are expenses other than purchased power that Purdue has difficulty accurately budgeting.

B. Discussion and Findings. As to the applicability of PSI's Summer Reliability Tracker to Purdue, we find that it is appropriate. Purdue concedes that it placed load on PSI's system at times of peak demand, and that PSI must carry and plan for reserves, including reserves to meet Purdue's needs. Purdue's self generation does not change the fact that it contributes to PSI's peak and should pay its fair share of purchased power costs – both energy and demand components. Concerning Purdue's complaint that PSI failed to update Purdue's contribution to peak demand to account for its additional generation, we find that not to be the case. Mr. Bailey explained that PSI took the additional self generation into account when calculating Purdue's contribution to peak demand. Additionally, we find that there is no basis for updating demand allocators every time costs are updated as proposed by Purdue. We agree with Mr. Bailey, that updating demand allocators outside of a rate case is not practical or cost effective

Finally, concerning the volatility of trackers, while we understand the concern, the record reflects that trackers were 10% of Purdue's bill, and electricity makes up less than 1% of Purdue's budget. Based on the evidence presented in this Cause, we do not find the volatility of trackers to be overwhelming to Purdue.

12. Holding Company Issues.

A. Evidence. CAC witness Christopher Williams testified that Cinergy's holding company and business unit structure lends itself to abuse and conflicts of interest, claiming that the organizational structure, operating policies and executive pay and performance programs of Cinergy since the merger between PSI and CG&E in 1994 have had the effect of "hollowing out"

PSI, significantly compromising the corporate integrity of PSI in performing its public service role in order to serve the total shareholder return goals of Cinergy. CAC Ex. A, p 7.

CAC witness Michael Sheehan also indicated that PSI has been "hollowed out" as Cinergy has been gradually dismantling PSI's management control over its utility business and operations and transferring that control to one or another of Cinergy's unregulated subsidiaries. CAC Ex. C. p. 36. He said that this was so with respect to control over PSI's operations, the division of loyalties in management, and the structure of incentive pay for executives. Dr. Sheehan pointed out that PSI managed much of its operations via service agreements with affiliates, which are unregulated and which, in his view, have their own interests to maximize. *Id.* at 37-40. He also pointed out that many of the management positions "ostensibly working for PSI and having loyalties to PSI and its function as a regulated utility are employees of, or hold positions with, one or another of Cinergy's unregulated subsidiaries." *Id.* CAC witness Mr. Biewald claimed that the JGDA was extremely complex and subject to manipulation. CAC Ex. B, pp. 22-23. He said that each of the 14 PSI officers listed in Cinergy's 2002 Annual Report on Form 10-k is an officer of at least one other unregulated Cinergy subsidiary or Cinergy itself, and none is actually employed by PSI, but rather, by Cinergy Services Inc., or Cinergy Power Generation Services Inc. *Id.* at 41.

Dr. Sheehan also claimed that the structure of executive incentives at Cinergy predominantly favor improving the financial condition of Cinergy, as opposed to PSI. Dr. Sheehan concluded that Cinergy's executive incentive programs serve to direct the attention of PSI's executives and affiliate executives working at PSI away from PSI's public utility goals and responsibilities and focus it, instead, on Cinergy's goals, which are largely directed to its unregulated companies and operations. *Id.* at 43. As to what should be done about this, Dr. Sheehan recommended that this Commission establish a separate docket to investigate the ongoing dismantling of PSI via Cinergy's structural changes, and the accounting ramifications of the resulting already dense web of inter-affiliate, less than arms length transactions, claiming "there is too much smoke here to safely ignore." *Id.* at 44.

Both CAC and the OUCC also urged this Commission to initiate a separate investigation into PSI's implementation of the 2002 Joint Generation Dispatch Agreement, citing concerns with PSI's implementation protocols. OUCC witness Mr. Endris testified that an investigation was needed to fully understand the tremendous complexity of intra-company energy transfers and to ensure that customers have not been short-changed. Pub. Ex. No. 6, p. 52.

PSI witnesses Esamann and Reising disagreed with CAC's claims. Mr. Esamann observed that there are numerous safeguards in place to guard against abuse and conflicts of interest, and pointed out that many benefits and synergies (cost savings) accrue to PSI by virtue of its participation in a holding company, service company and business unit structure. The safeguards in place, he said, include federal and state laws; SEC, FERC and IURC oversight; PSI's own affiliate guidelines; FERC code of conduct requirements; the provisions of Cinergy's own service agreements; and, the provisions of agreements such as the 2002 JGDA and the Joint Transmission System Agreement ("JTA") between PSI and CG&E. Pet. Ex. DD, p. 36.

Mr. Esamann pointed out that the Cinergy merger has also allowed PSI and CG&E to share their best practices in a variety of areas that benefit customers, such as power production operations, T&D system operations, and customer service operations. Being part of a merged, holding company structure, he added, also allows PSI and CG&E to share both operating and financial resources. Important to customers, he said, is the fact that PSI has access to CG&E operating resources – such as CG&E generation through the JGDA, CG&E line trucks and line crews for storm restoration purposes, and a variety of expertise shared between the Cinergy companies. *Id.* at 37-38.

Expanding on Mr. Esamann's observation, Mr. Reising gave examples of protective financial safeguards in place, consistent with the legal separation between PSI and Cinergy. For example, the creditors of PSI clearly have the priority claim on the assets of PSI. Further, PSI is legally prohibited by the Public Utility Holding Company Act of 1935 ("PUHCA") from loaning money to Cinergy. PSI is also prohibited from guaranteeing the debt of Cinergy. Finally, there are no cross defaults between Cinergy debt and PSI; in other words, if there would be a default on Cinergy debt, that default would not trigger a default on PSI debt. *Pet. Ex. EE*, pp. 12-14.

Mr. Reising pointed out the financial support that Cinergy and the holding company structure have provided to PSI. For example, PSI's dividend payout ratio averaged only 31% for the four-year period from 1999 to 2002. By virtue of being a part of the Cinergy holding company structure, PSI was able to rely on its affiliates to fund the majority of Cinergy's dividend payout during this period. PSI's lower dividend payout ratio allowed PSI to improve its liquidity by almost \$240 million versus what it would have been if PSI had met a standard 70% dividend payout ratio in each of those years.

Mr. Esamann disagreed with CAC's contention, and that of the OUCC, that the Commission should initiate a separate investigation into Cinergy's implementation of the JGDA. He observed that since April, 2002, PSI has worked hard to implement the JGDA in a manner consistent with both the spirit and letter of the agreement, working to fashion a number of business rules to implement the JGDA in a fair and objective manner. The Company's primary business rules, and the system energy transfers that take place under the JGDA, he observed, have been presented to the Commission in PSI's various FAC proceedings. Additionally, consistent with the terms of the JGDA and the underlying Indiana settlement agreement, he pointed out, the hourly market prices at which system energy transfers are priced are regularly audited by an independent audit firm, Jefferson Wells, and the related audit reports have also been presented to the Commission and to the OUCC in connection with PSI's FAC proceedings. *Id.* at 38-39.

Mr. Esamann further emphasized, as did Staff witness Borum, that the 2001 Indiana settlement agreement that accompanied the JGDA required PSI to meet with the Indiana signatory parties in January 2004, to assess the feasibility, efficacy and equity of continuing joint system dispatch and system energy transfers. Subsequently, in March 2004, PSI must initiate a proceeding before the Commission to begin a formal assessment of the functioning of the JGDA.

Id. at 39.¹¹ Given these commitments and PSI's ongoing presentation of information concerning JGDA system energy transfers in its quarterly FAC proceedings, Mr. Esamann saw no reason for a separate Commission investigation into JGDA issues. *Id.*

B. Discussion and Findings. We believe that the record has adequately established numerous benefits of its merger – financial, operational, and synergistic -- with CG&E, as well as the continuing presence of safeguards in place to protect against abuses. As for the JGDA, that Agreement will be the subject of our further review, under Cause No. 41954. Therefore, it would be premature for this Commission to establish an investigation into the JGDA at this stage of the proceedings. As for allegations that PSI has been "hollowed out" we do not believe that the evidence supports such a claim. This Commission is satisfied that PUHCA, in conjunction with additional safeguards, including the Commission's full jurisdiction over PSI's operations, remains in place. Therefore, based on the evidence presented on this issue we do not believe an investigation is warranted on this issue and hereby deny all requests for such an investigation.

13. Environmental Planning.

A. Testimony Presented by the CAC. CAC witness Chris Williams stated that the CAC is concerned that PSI has essentially adopted a policy of making capital investments to address environmental risk only to the extent and at the times required by law. CAC Ex. A, p. 8. CAC witness Mr. Bruce Biewald also noted that PSI's actions reflect an approach of doing the minimum required. According to Mr. Biewald, PSI has reduced its DSM expenditures, is too reliant on coal, and doesn't promote renewables. CAC Ex. B, pp. 37-43.

Mr. Biewald indicated that he believes there is a disparity between the way Cinergy/PSI manages its financial risk versus the way it manages environmental risk, arguing that PSI could more actively address its environmental risks. He conceded PSI has made some effort to diversify its generation mix, to reduce emissions from its existing plants, and to implement demand-side management programs. Mr. Biewald cited EPA data (eGRID¹¹) showing Cinergy's generation mix in the year 2000 was 98% coal. Cinergy's emissions of CO₂, SO₂, and NO_x in 2000 were 67 million tons, 560 thousand tons, and 154 thousand tons, respectively. According to Mr. Biewald, PSI's share of Cinergy's generation was about 59% in 2000 amount. PSI's share of CO₂ emissions was also 59% of the total. For SO₂, PSI's share was higher (66% of total) and its NO_x share was lower (53% of total). These shares are based upon EPA's eGRID data. Mr. Biewald concluded that PSI should serve its customers with low cost, reliable power in a way that also diversifies the resource mix, cleans up the existing fleet of plants, and expands energy efficiency programs.

Mr. Biewald recognized that Cinergy has made investments in selective catalytic reduction ("SCR") to control NO_x emissions. He also noted that the repowering of Noblesville has increased the station's capacity and switched its fuel from coal to gas. This represents

¹¹ The initiation of discussions, as agreed in Cause No. 41954 (*Ind. Util. Reg. Comm'n*, September 11, 2001), was extended at the request of the parties until June 1, 2004.

progress toward improving the efficiency of Cinergy's generating mix, and diversity of its fuel supply, but Noblesville represents just 300 MW of capacity in a system of about 12,000 MW. Mr. Biewald noted that PSI progress in diversifying its resource mix is very gradual, and not designed to meet environmental mandates that are not yet in place. Carbon dioxide emissions, fine particulates, and toxics such as mercury will likely need to be addressed by Cinergy in the near future.

Mr. Biewald also testified that demand side programs and renewable generating resources will be essential components of a low cost and prudent strategy to manage these emissions and associated risks. Given the Company's heavy reliance on coal generation and its pronounced vulnerability to new environmental regulations, Mr. Biewald suggests that aggressively pursuing DSM would seem to be a prudent environmental risk management policy that the Company should not overlook. In addition, Mr. Biewald testified that if PSI were to utilize an increased share of renewable generating capacity, this would also serve to reduce its exposure to environmental risks at costs that could reasonably be borne by customers. Mr. Biewald concluded his testimony by recommending that PSI should aggressively develop and implement cleaner generating resources and energy efficiency programs, in order to better serve its customers.

B. PSI Testimony. PSI witnesses agreed that environmental compliance planning is complex and that a utility the size of PSI cannot wait until the last minute, or until all requirements are fully known to begin such planning. Mr. Roebel testified that even after environmental compliance equipment is installed there remain operating challenges that must be addressed. He also described how PSI had to begin construction of, not just plan for, SCRs for compliance with the NO_x SIP Call while a court order staying those requirements was still in place. Mr. Roebel went on to explain that PSI has been actively planning and evaluating options for compliance with what the Company believes will be more stringent environmental requirements in the near future. Pet. Ex. KK, p. 4. Similarly Mr. Esamann explained that he believed that it is good public policy to encourage utilities such as PSI to present their environmental compliance plans to regulators and interested customer groups. Mr. Esamann went on to state that with mercury rules imminent the Company anticipates that it will be submitting an environmental compliance and cost recovery plan to the Commission in 2004. Pet. Ex. DD p. 35.

C. Discussion and Findings. It is very clear for the record in this proceeding that major coal burning utilities such as PSI face significant environmental compliance costs and challenges. We agree with the CAC that it is prudent for PSI to begin evaluating options and planning to address environmental compliance issues well before the specific requirements are known with absolute certainty. Due to PSI's reliance on coal, the development of an improved resource mix, including the implementation of cleaner generating resources in conjunction with the utilization of energy efficiency programs, must be undertaken by PSI in order to ensure long term benefits to its customers. Accordingly, we anticipate and expect that future environmental compliance issues will come before us for review, and anticipate that PSI will take the steps necessary to address environmental compliance issues in a proactive manner consistent with our findings herein.

14. The FERC-Seven-Factor Test. PSI witnesses Ronald R. Jackups and Edward F. Kirschner explained the FERC Seven Factor Test for classifying PSI's facilities as transmission or distribution and why PSI is seeking this Commission's approval of such classification in this case. Mr. Jackups testified that the FERC's Seven-Factor Test provides specific criteria to determine whether facilities should be classified as transmission facilities or distribution facilities under the Uniform System of Accounts. Pet. Ex. M, p. 63. Mr. Kirschner described in detail each of the tests. Pet. Ex. N, pp. 8-13.

Mr. Jackups said that the Midwest ISO Agreement requires that, prior to the end of the fourth year of the transition period of the Midwest ISO, each transmission owner shall file a request with the appropriate regulatory authority for a determination as to which of its electric system facilities are transmission facilities and which are distribution facilities, in accordance with the FERC's Seven-Factor Test. Pet. Ex. M, pp. 63-64. Mr. Jackups explained that because of the potential for changes in the transmission and distribution components of PSI's retail electric rates when the FERC's Seven-Factor Test is implemented, PSI elected to request this Commission's review of the Company's implementation of the FERC's Seven-Factor Test in this proceeding, so that any changes ordered by this Commission could be implemented within the context of this general rate case. Pet. Ex. M, p. 64.

Mr. Kirschner testified that the application of the FERC Seven-Factor Test resulted in the determination that all of PSI's electric delivery system facilities rated 69 KV and above, networked or radial, should be classified as transmission, and that all of PSI's electric delivery system facilities rated below 69 kV should be classified as distribution. Pet. Ex. N, p. 8. This represented no change from PSI's previous classification of its facilities. Pet. Ex. N, pp. 8 and 14.

No party contested these classifications or objected to PSI's implementation of the FERC's Seven-Factor Test in this proceeding. We find that PSI has properly implemented the test and has appropriately determined which of its facilities should be classified as transmission facilities and which should be classified as distribution facilities for purposes of the FERC Seven-Factor Test.

15. Compliance with Hold Harmless Commitment. PSI witness John P. Steffen submitted testimony regarding the Company's compliance with the "hold harmless" provisions of the Indiana Settlement Agreement as approved by this Commission in its March 29, 1994 Order in Cause No. 39897. Mr. Steffen testified that under the terms of the Settlement Agreement as approved by the March 29, 1994 Order, PSI was required to make affirmative showings with respect to net merger production capacity savings, net merger production cost savings and net merger non-fuel O&M cost savings. Pet. Ex. C, p. 28. Mr. Steffen also said that the March 29, 1994 Order also required PSI to submit, as part of certain post-merger general rate case proceedings, information regarding 16 different categories. Mr. Steffen sponsored an exhibit that set forth this required information. *Id.* at 27-31; Pet. Ex. C-8.

As to production capacity savings, Mr. Steffen said that Ms. Diane Jenner's direct testimony shows that PSI has used a target planning reserve margin of less than 20%, PSI's previous standalone margin, since the 1994 merger. Pet. Ex. C, p. 31. With respect to production cost savings, Mr. Steffen noted that under the 2002 Joint Generation Dispatch Agreement and as part of the Indiana Settlement Agreement in Cause No. 41954, PSI committed to provide its retail electric customers with \$7.3 million in annual joint dispatch savings rate credits through 2004. Mr. Steffen testified that since April, 2002, PSI has implemented these credits through its fuel adjustment clause. *Id.* at 32. As to non-fuel O&M costs, Mr. Steffen sponsored an exhibit which showed that O&M costs for this proceeding would have been an estimated \$8.3 million higher but for the merger. Pet. Ex. C-9. Mr. Steffen said that converting the non-fuel O&M costs to a per customer basis shows that PSI's annual non-fuel O&M cost per customer today is \$579, compared to an indexed PSI annual non-fuel O&M per customer of \$583 in 1992. Pet. Ex. C, p. 37.

Mr. Steffen testified that the non-fuel O&M savings produced by the merger exceed the cost of the merger and, therefore, PSI's customers have been held harmless from the effects of the merger and are clearly better off as a result of the merger. *Id.* at 38. Mr. Steffen added that it was noteworthy that this demonstration was made by referencing only non-fuel O&M savings, without any consideration given to the savings produced by deferred capacity, and joint dispatch and financing and fuel cost savings.

No party disputed Mr. Steffen's testimony regarding PSI's compliance with the "hold harmless" provisions of the Settlement Agreement in Cause No. 39897. We find that PSI has complied with the provisions of that settlement and the terms and conditions of the March 29, 1994 Order approving it.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. PSI shall be, and hereby is, authorized to place into effect rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of \$107,344,000 which represents an increase in operating revenues of 8.36%. Said rates will produce total jurisdictional electric operating revenues of \$1,406,596,000 and, on the basis of annual jurisdictional electric operating expenses of \$1,139,096,000, will result in annual jurisdictional electric utility operating income \$267,500,000. PSI is hereby authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order.

2. PSI shall file with the Electricity Division of this Commission, appropriate tariffs using the rate design criteria specified in Finding No. 9 of this Order, including the rates and charges authorized herein for Phase I. Such Phase I rates and charges shall be effective upon such filing, subject to refund, pending review and approval by the Commission's Electricity Division. For Phase II, PSI shall file with the Commission's Electricity Division appropriate

tariffs for such phases, including the applicable rates and charges authorized herein, at least forty-five (45) days before their respective implementation dates in order to allow sufficient time for review and approval. The rates and charges for Phases II shall be effective upon approval of the filed tariffs.

3. PSI's filing of its new Phase I rates and charges with the Commission's Electricity Division shall be accompanied by a simultaneous refiling of: (a) its fuel cost charge in effect on the date of the approval of such new rates and charges, modified to reflect the new base cost of fuel provided for in Finding No. 10A of this Order; (b) its Clean Coal Operating Cost Revenue Adjustment, Standard Contract Rider No. 71 to reflect the effect of costs that will be contained in base rates in accordance with the provision of this Order; and (c) its Qualified Pollution Control Property Revenue Adjustment, Standard Contract Rider No. 62 to reflect the effect of costs that will be contained in base rates in accordance with the provision of this Order.

4. PSI shall be, and hereby is, authorized to recover in its retail electric rates its deferred Dynegy buyout costs, as determined in accordance with Finding No. 6D(13)(a) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its deferred Dynegy buyout costs, as determined in accordance with that same Finding.

5. PSI shall be, and hereby is, authorized to recover in its retail electric rates its deferred transaction costs and costs to achieve benefits associated with the 1994 Cinergy merger, as determined in accordance with Finding No. 6D(13)(b) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its deferred transaction costs and costs to achieve benefits associated with the 1994 Cinergy merger, as necessary.

6. PSI shall be, and hereby is, authorized to: (a) recover in its retail electric rates its Midwest ISO-related deferred administrative costs, all as determined in accordance with Finding No. 6D(13)(c) of this Order; and (b) to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its Midwest ISO-related deferred administrative costs, all as determined in accordance with that same Finding.

7. PSI shall be, and hereby is, authorized to recover in its retail electric rates its post-in service deferred depreciation and AFUDC, as determined in accordance with Finding No. 6D(13)(d) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its post-in service depreciation and AFUDC, all as determined in accordance with that same Finding.

8. Commencing with the first day of the month coincident with or immediately following the effective date of this Order, PSI is hereby authorized to place into effect the depreciation rates approved in Finding No. 6D(1) of this Order.

9. PSI's proposed classification of its electric delivery system facilities as transmission facilities and distribution facilities, as described in Finding No.14 of this Order, shall be, and hereby is, approved for purposes of the FERC Seven-Factor Test.

10. PSI shall be, and hereby is, authorized to implement the charges and credits for the payment of its Indiana property taxes incurred after the effective date of this Order in the manner provided in Finding No. 6D(11) of this Order.

11. PSI shall be, and hereby is, authorized to implement the Summer Reliability Standard Contract Rider, NO_x Emission Allowance Standard Contract Rider, and Midwest ISO Cost and Revenue Adjustment Standard Contract Rider, all as determined in Finding No. 9A of this Order.

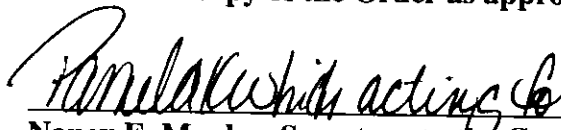
12. PSI shall be, and hereby is, directed to participate in a collaborative process involving Commission Staff and other parties concerning PSI's RTP Program, all as provided in Finding No. 9B of this Order.

13. This Order shall be effective on and after the date of its approval.

HADLEY, RIPLEY AND ZIEGNER CONCUR; McCARTY AND LANDIS ABSENT:

APPROVED: MAY 18 2004

**I hereby certify that the above is a true
and correct copy of the Order as approved.**



Nancy E. Manley, Secretary to the Commission

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 5th day of December 2008.

CASE NO. 06-0960-E-42T

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY both
dba ALLEGHENY POWER,

Rule 42T application to increase electric rates and charges.

CASE NO. 06-1426-E-D

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY both
dba ALLEGHENY POWER,

Request for approval of change in depreciation rates in accordance with Rule 20 of the Commission Rules of Practice and Procedure.

COMMISSION ORDER

BACKGROUND

On July 26, 2006, Monongahela Power Company ("Mon Power") and The Potomac Edison Company ("Potomac Edison") both dba Allegheny Power (jointly "Companies"), filed revised tariff sheets reflecting increased rates and charges of approximately 12.8 percent annually, or \$99.8 million, for furnishing electric service to their customers in West Virginia. The proposed rates and charges were to become effective on August 25, 2006. The requested increase reflected the net impact of a traditional base rate increase as well as the proposed reinstitution of the Expanded Net Energy Cost ("ENEC") mechanism. On August 22, 2006, The Commission suspended the revised tariff sheets and deferred new rates for the Companies until May 23, 2007.

On September 26, 2006, the Companies filed proposed depreciation rates pursuant to Rule 20 of the *Rules of Practice and Procedure*, 150 C.S.R. 1, which filing was docketed as Case No. 06-1426-E-D. The Companies requested that the depreciation rates not take effect immediately, and that the Commission approve the depreciation rates in sufficient time to be reflected in the base rates established in the final order in Case No. 06-0960-E-42T. The Commission suspended the proposed depreciation rates until May 23, 2007, the same date the proposed customer rates and charges in Case No. 06-0960-E-42T were set to go into effect, and consolidated the two cases. *See*, Commission Order entered December 20, 2006.

The Consumer Advocate Division of the Public Service Commission ("CAD"), the West Virginia Energy Users Group ("WVEUG"), the International Brotherhood of Electrical Workers Local 2357 ("IBEW"), Kroger Company, Utility Workers Union of America ("UWUA"), Monongalia County General Hospital ("Mon General") and West Virginia Community Action Partnership ("WVCAP") filed petitions to intervene in this case. Those petitions were granted by the Commission. Certain individuals also filed petitions to intervene. The individual petitions to intervene were denied by the Commission because the interests of the individuals were already represented by the CAD.

After hearings and briefing the Commission issued an Order on May 22, 2007 ("Original Rate Order").¹ In that Order, the Commission established new depreciation rates for the Companies, approved an ongoing procedure for current recovery, deferral of over- or under-recoveries and true-up of the Companies' net fuel costs and certain other components of cost and revenue designated as ENEC. For purposes of base rate revenue requirements the Commission applied a return on equity of 10.50 percent to the Companies' capital structure to arrive at an overall return of 8.44 percent. This return was applied to a rate base of \$1,178,874,203 resulting in a return on rate base of \$99,496,983, which, along with allowances for operation and maintenance expenses, depreciation and taxes, resulted in a revenue requirement of \$1,082,732,803. In calculating this revenue requirement, the Commission included the ENEC components offset by an equal level of going level revenue to essentially zero out the ENEC components. The resulting revenue requirement was lower than the Companies' going level revenue and the Commission revised rates resulted in an overall net base rate decrease of \$6,183,900.

On June 15, 2007, the Companies filed a Petition requesting that the Commission reconsider and clarify the Original Rate Order. In that Petition, the Companies also requested that the Commission set the issues raised in the petition for a hearing. The Companies contended that the Commission should reconsider its earlier decision because the Commission had (i) misapprehended important ratemaking principles; (ii) failed to

¹The procedural background set forth in this Order is abbreviated. Please refer to the Original Rate Order for a more complete recitation of the procedural history of this case.

take proper account of uncontroverted evidence in the record; and/or (iii) miscalculated adjustments it had determined to make.

The Companies claimed that the Original Rate Order resulted in revenues that are lower than the position of the Companies regarding their cost of service and that the rates ordered by the Commission are not just and reasonable. The Companies asked that the Commission reconsider four specific revenue requirement determinations. These were:

- 1) the Consolidated Tax Adjustment ("CTA") applied by the Commission to determine an appropriate level of income tax expense;
- 2) the determination that the rate base of the Companies should be reduced by recording certain accumulated deferred income taxes ("ADITS") as an offset to the Companies' proposed recognition of increased income tax expense associated with the net transfer of generating assets on January 1, 2007 (In the alternative the Companies asked that the Commission recalculate the correct amount for this rate base credit if the ADITS in question were not eliminated altogether.);
- 3) the determination of appropriate depreciation rates for the Companies; and
- 4) the requirement that bonuses pursuant to a variable pay plan should be allowed for ratemaking purposes, but only if responsiveness to customers was a factor for evaluating employee performance.

In addition to asking for reconsideration with regard to the above listed items (or correction of the ADITS amount), the Companies requested that the initial annual review of right-of-way maintenance be changed to coincide with a twelve-month period ending on the last day of May, 2008.

The Staff, CAD and WVEUG responded to the Petition for Reconsideration. The positions of each of these parties are discussed below.

DISCUSSION

A. Consolidated Tax Adjustment

In its Original Rate Order, the Commission calculated the income taxes of the Companies for ratemaking purposes after taking into consideration significant tax losses experienced by various companies which file a consolidated income tax return with the Companies ("Consolidated Tax Group"). The Commission considered the impact of tax losses for all members of the Consolidated Tax Group after adjusting to reflect normalization of differences between book and tax depreciation. Companies witness, Mr Warren, had described this methodology as a CTA to differentiate it from a methodology

which considers only the tax loss of the parent company. Mr. Warren referred to the parent company loss methodology as a Parent Company Loss Adjustment ("PCLA").

1. Arguments of the Companies

The Companies requested that the Commission reverse its initial decision on this matter and not use the tax losses of all affiliated members of the Consolidated Tax Group to calculate a consolidated tax savings, or an effective income tax rate.² The Companies further argued that even if the Commission did consider the tax losses of all affiliated members of the consolidated tax group, there were alternative "time value" methods of considering the effects of consolidated tax savings and the Commission should consider those methods. The Companies argued that the approach taken by the Commission was ill-conceived and contrary to the historic approach of the Commission to the issue. Petition for Reconsideration at 3-4. They contend that the Commission applied a version of CTA that is even more suspect than the highly discredited Pennsylvania model, which had been described by witnesses and cited by the Commission, and which itself is conceptually inferior to the methodologies implemented by two other jurisdictions that apply a version of the CTA. *Id.* at 4.

The Companies also requested that if the Commission does not change its effective tax rate or "actual taxes paid" approach for setting the income tax component of revenue requirements in this case that it provide for recovery of taxes when the circumstances giving rise to the Original Rate Order have been resolved. To accomplish this, the Companies suggested that the Commission should allow the Companies to begin recovery of their tax expenses immediately upon the exhaustion of the net losses cited in the Original Rate Order. Petition for Reconsideration at 5. The Companies argued that, without some mechanism for expedited consideration of documented income tax expenses, once such tax expenses are incurred they will be subjected to additional delay in the recovery of income tax expense until the completion of a subsequent rate proceeding. *Id.*

In requesting reconsideration of the CTA decision, the Companies argued that the Commission historically calculated an effective income tax rate after considering the tax losses of the parent company of a consolidated group, but not the tax losses of other affiliated companies. The Companies state that this "parent company" tax loss approach was adopted by the Commission in a number of prior cases, including cases for the Companies. Petition for Reconsideration at 5. Specifically, the Companies noted that the Commission had used only the parent company tax loss for purposes of calculating an

² The Commission refers to both "consolidated tax savings" and "effective tax rate" in its discussion of income taxes. The consolidated tax savings is defined as the difference, stated as a percentage, between the total income tax payable by individual members of the consolidated group and the total income tax payable by the consolidated group after taking losses of individual members of the group into account. The effective income tax rate is the net tax rate after adjusting the statutory tax rate by the consolidated tax savings. For example, if the statutory tax rate is 35 percent and the consolidated tax savings is 50 percent, the effective tax rate would be 17.5 percent.

effective income tax rate in West Virginia American Water Company, Case Number 03-0353-W-42T ("2003 WVAWC case"). *Id.*

The Companies maintain that the use of any effective tax rate other than the rate that would have applied to them on a separate return basis was wrong. The Companies continue to argue at length that they have a valid income tax expense based on their separate return basis taxes because this amount is paid to their parent company pursuant to a Tax Sharing Agreement ("TSA") among the affiliated companies within Allegheny Energy. The Companies point out that their witness, James Warren, provided testimony about tax allocation agreements in general and the TSA in particular. Mr. Warren testified that the TSA establishes a reasonable related-party economic relationship among parties in the Consolidated Tax Group. Petition for Reconsideration at 10. They further note that the TSA is the mechanism through which the income tax payments of the Companies are transmitted when those payments, by virtue of the Consolidated Tax Group income tax liability, are paid to the taxing authorities. In other words, the TSA acts as a clearinghouse for the tax liabilities due from and tax benefits due to the various group members. *Id.*

2. Responses to Arguments Made by the Companies

The CAD, Staff and WVEUG responded to the Petition for Reconsideration. *See generally*, responses filed on July 9, 2007. Each respondent disagreed with the position of the Companies and supported the Commission determination that the effective current income tax rate for the purposes of this case was zero. WVEUG argued that:

[T]he record that has been developed and relied upon by the Commission in this proceeding demonstrates two undisputed points: (1) Allegheny has paid zero dollars in taxes since 2000 (and will likely not pay taxes for an additional four years); and (2) Allegheny Energy's losses from its unregulated entities have in fact harmed the regulated utilities and their ratepayers in the form of increased rates and the shifting of risk to ratepayers from shareholders.

WVEUG Response at 5. The CAD, in supporting the original decision of the Commission with regard to the consolidated tax savings issue, argued:

At page 7 of their Petition the Companies state: 'The Companies' **accounting records** appropriately reflect income tax expense incurred and paid by the Companies. **But for the Companies' participation in consolidated tax returns**, the Companies' incurred income tax expense would have been paid directly to the taxing authorities and fully reflected in the rates established in the Order.' [Emphasis added] These two sentences sum up the frailty of the Companies' position on income taxes. Making an accounting entry is not the same as paying taxes to a taxing authority. . . . While the Companies would like to pretend that they do not participate in a consolidated tax return, the facts are that the Companies do indeed

participate in a consolidated tax return, and as a result have not made income tax payments to a taxing authority since 2000.

CAD Response at 7. (Emphasis in original). Staff, in addressing the issue of payments made to parent company Allegheny Energy as a “clearing house” rather than to a taxing authority, argued:

The Companies argue their tax expense is a prudently incurred expense and the Commission has no right to deny it. Staff finds this curious since it has clearly been established that no money will be paid to the State or Federal Government. Merriam-Webster defines a tax as ‘a charge usually of monies imposed by authority on persons or property for public purposes.’ So, one would reasonably expect a prudent ‘tax’ expense to be paid to an authority figure and that money would then be used for a public purpose. Therefore, Staff would disagree with the Company’s description of this ‘tax’ expense as prudently incurred. Staff asserts the removal of this expense is permissible and does not constitute an unconstitutional taking of property in violation of the US and West Virginia Constitution.

Staff Response at 3-4.

3. *Commission Decision*

The Commission does not agree with the positions set forth by the Companies on the issue of CTA. In the Original Rate Order in this case the Commission explained why it was adopting a consolidated tax savings calculation and an effective income tax rate which uses the losses of the entire Consolidated Tax Group, rather than only the losses of the parent company. *See generally*, Original Rate Order at 28-33. The Commission noted that this case contains a fact pattern that is significantly different from the 2003 WVAWC case cited by the Companies. *Id.* at 31. In the 2003 WVAWC case, the losses of the parent company accounted for ninety-seven percent of the losses. In this case, the losses of the parent are slight in comparison to the losses of the group as a whole. Moreover, in the 2003 WVAWC case, that company was a taxpayer with no loss carry forwards. *Id.* “Therefore, the only effect the losses had in that case were to lower the effective tax rate.” *Id.* In this case, we noted that the Consolidated Tax Group had not been a taxpayer since 2000 and probably will not be a taxpayer for several more years due to the impact of prior years tax losses. *Id.*

The Commission finds that the argument of the Companies, that payments made to their parent based on a separate return tax calculation are “real, reasonable, and prudent expense” and that it is not relevant whether income taxes are transmitted to a taxing authority, is unreasonable and incorrect.

The Companies argued that payments made to Allegheny Energy represent tax expenses even when there are no taxes paid to the federal or state taxing authorities, stating: “The Companies unquestionably incurred state and federal income tax expense

during the test year and paid those amounts to Allegheny Energy pursuant to their contractual obligations under the Tax Sharing Agreement.” Petition for Reconsideration at 8.

The Companies go on to argue that they never pay income taxes directly to a taxing authority, but rather transmit their tax payments to Allegheny Energy which, in turn pay taxes to the taxing authorities. The Companies either miss the point or are purposely confusing the issue. This issue relates to income tax expense, not payments or advances to associated companies. The Companies cannot create a real, reasonable and prudent tax expense by agreeing to funnel funds for tax payments through an affiliated company when those funds do not end up being transmitted to a taxing authority. The Supreme Court of Appeals of West Virginia recognized the difference between a real expense and an “artificial” expense in upholding the Commission’s consolidated tax savings calculation in *Virginia Elec. and Power Co. v. Public Serv. Comm’n*, 161 W.Va. 423, 429, 242 S.E.2d 698, 702 (1978):

It seem to us that there is no difference in the Commission’s ruling on the point, than would be the case if the utility attempted to put into its rate base the cost of materials to repair lines, for example, at a catalogue price, where in fact the Company paid only half that price. It could not be argued that the utility’s consumers should pay rates based upon an artificial price, not actually paid; and it likewise would seem reasonable that customers should not pay rates based upon a tax expense not actually paid.

The Commission looks to the actual tax returns within which the Companies taxable income is included to determine a proper income tax expense for ratemaking purposes. In this case, our review of those tax returns indicates that the effective current income tax rate reflected in a five-year average of those tax returns is zero. The Commission specifically rejects the argument that payments made to affiliates based on a separate return basis tax calculation are reasonable and prudent income tax expenses of the Companies when no taxes are paid to a taxing authority.

The Companies have not made any arguments that lead the Commission to believe that our decision was incorrect. In the Original Rate Order, we noted that at the beginning of 2007, Allegheny Energy had net operating loss carry forwards of approximately \$1.4 billion. Original Rate Order at 32. The evidence before the Commission clearly indicates that this magnitude of loss carry forwards will wipe out future tax liabilities for an extended period of time. Given the evidence set forth in the record of this case and the large loss carry forward available to the Consolidated Tax Group, allowing an income tax expense in this case would be requiring customers to pay for income taxes that will not be paid to the federal or state government. We determine that would not be reasonable. We further determine that a payment to Allegheny Energy as a “clearing house” is not an appropriate income tax expense for ratemaking purposes.

We further determine that we should not adopt the request that, if we will not treat these payments to Allegheny Energy which are not transmitted to the federal or state

taxing authorities as current expenses of the utility, we should treat them as deferred credits subject to a time value credit back to the utilities until they are used to pay income taxes. We note that the Companies are arguing that the Commission analysis of consolidated tax savings is not a reasoned analysis. This argument seems to be based on the objection of the Companies to the fact that the Commission did not discuss at length other consolidated tax savings approaches, such as their description of a "time value" treatment of consolidated tax savings as opposed to the Commission method, which the Companies call a "cost of service" method. We have fully considered all of the options suggested by the Companies, including the "time value" approach and we find that the method adopted by the Commission is consistent with an approach which requires a utility to pay its proportionate share of a consolidated tax liability.

The Commission is not ignorant of, and did not fail to consider, alternative approaches to consolidated tax savings, including the preference of the Companies that we disregard consolidated tax savings altogether, or that we adopt a stand-alone attribution (benefits/burdens) approach, or that we adopt a "time value" method used by some states. Just as we do not adopt the same approach as other regulatory agencies that choose to disregard the effect of filing a consolidated tax return on the effective tax rate of the consolidated group, neither do we adopt a "time value" hybrid described, but not fully supported, by the Companies. The Commission approach is not backward looking, and it is not intended to defer benefits of consolidated tax filings subject to some future turn-around with "time value" compensation to utilities that provide advance cash benefits to loss companies. We use historic data to derive a reasonable expectation of future effective tax rates. The Commission notes that we average the effective tax rates derived from historic data to smooth significant swings; however, we believe that the effective tax rate approach will result in a cost of service tax liability for ratemaking purposes that represents our regulated utilities' proportionate share of actual taxes paid in the future.

The Commission does not adopt the stand-alone methodology advocated by the Companies. We find that the Companies' arguments that other regulatory agencies and certain court decisions favoring the stand-alone methodology are neither controlling with regard to our decision on consolidated tax savings in this case, nor persuasive for changing the Commission methodology. For example, the Companies argued that, "[i]n *City of Charlottesville v. Federal Energy Regulatory Commission*, 774 F.2d 1205 (D.C. Cir. 1985) . . . the Federal Court of Appeals for the District of Columbia conducted an extensive analysis of the 'actual taxes paid' idea advanced by petitioners there, describing and affirming the FERC's application of a 'benefits/burdens' test." Petition for Reconsideration at 22.

The Commission has reviewed the analysis of the court in *City of Charlottesville*, and notes that the court was giving deference to a FERC decision which had changed from an effective tax rate approach to a stand-alone approach. Before even analyzing the "benefits/burdens" concept, the court noted that this concept stemmed from the adoption of a "stand-alone" tax calculation approach by the FERC. "In sum, we are persuaded that the Commission's stand-alone approach is reasonable enough to survive our highly deferential review." 774 F.2d at 1216. Had the FERC not changed its policy and

continued to apply what the court in *Charlottesville* referred to as “the more venerable, the so-called ‘flow-through’ methodology,” the “benefits/burdens” test underlying the stand-alone approach would not have been an issue with the court. *Id.* at 1206.

This Commission has not adopted the stand-alone approach. Thus, the affirmation of the FERC’s “benefits/burdens” analysis by the court in the *City of Charlottesville* does not apply to our determination of an effective income tax rate for the Companies in this case. The Commission finds more instructive the United States Supreme Court analysis in *Federal Power Comm’n v. United Gas Pipe Line Co.*, 386 U.S. 237, 87 S.Ct. 1003, 18 L.Ed. 2d 18 (1967), finding that

Respondents insist that in making the allocation the Commission would violate the statute unless in every conceivable circumstance, including this one, United is allowed an amount for taxes equal to what it would have paid had it filed a separate return. In their view United should never share in the tax savings inherent in a consolidated return, even if on a consolidated basis system losses exceed system gains and neither the affiliated group nor any member in it has any tax liability. This is an untenable position and we reject it. Rates fixed on this basis would give the pipeline company and its stockholders not only the fair return to which they are entitled but also the full amount of an expense never in fact incurred. In such circumstances, the Commission could properly disallow the hypothetical tax expense and hold that rates based on such an unreal cost of service would not be just and reasonable.

386 U.S. at 243-44.

The Commission does not find that it would be reasonable to depart from the income tax approach adopted in the Original Rate Order. We continue to apply the consolidated tax savings/effective current income tax rate approach which the United States Supreme Court has determined to be reasonable and permissible.

The Companies argue that application of a CTA violates their right to adequate notice. Petition for Reconsideration at 26. We disagree. The Companies may be opposed to any variety of CTA, however, they should not have been surprised by our decision which adopted a consolidated tax savings, or effective current income tax rate. Both Staff and the CAD prefled testimony advocating a consolidated tax savings approach. *See generally*, Testimony of Mr. Majoros for CAD and Mr. Pauley for Staff, both filed January 22, 2007. The Companies may be more opposed to the consolidated tax savings approach in this case than in prior cases because we have included all losses in our calculation of an effective tax rate. However, as we explained in our initial decision, and above, the effective tax rate methodology has not changed. The only change is that we have determined that the facts of this case require the inclusion of all losses in the calculation in order to arrive at an effective tax rate that is reasonably representative of the effective consolidated rate that will be experienced by the Companies prospectively.

We note that the Companies were well aware of our methodology based on past decisions and based on Commission rules. *Tariff Rule 42*, which sets forth the filing requirements for rate cases, puts all utilities that participate in a consolidated tax return on notice that we use a consolidated tax savings/effective tax rate based on such consolidated returns. Utilities are also on notice that all losses of the group must be used to calculate the consolidated tax savings and the effective tax rate. Specifically, the rule states: "Savings arising from the filing of a federal consolidated tax return shall, for purposes of rate consideration before this Commission, be stated as a percentage of tax on a separate return basis." Rule 42, *Rules for the Construction and Filing of Tariffs*, 150 C.S.R. 2. This requires the calculation of a tax savings based on the filing of a Consolidated Tax Group return with all loss companies. The Companies could not have been surprised or misled into thinking that the Commission would not consider tax losses of all members of the consolidated group. The rule goes on to set forth specific requirements for disclosing the taxable income or loss and tax loss carrybacks and carryforwards of all members of the Consolidated Tax Group, not simply the parent company or selected members of the consolidated group. Furthermore, in addition to the clear wording of the rule, the Companies were on notice that other parties to the case were strongly recommending that the Commission consider all loss companies for the purposes of calculating a consolidated tax savings.

While the Commission may decide on a case by case basis to exclude some of the tax losses for the purposes of a forward looking effective tax rate calculation, we continue to find that in this case the effective forward looking savings, "stated as a percentage of tax on a separate return basis" is one hundred percent. In other words, the effective income tax rate for the purposes of this case is zero.

We now turn to the request made by the Companies that, if the Commission does not change its effective tax rate or "actual taxes paid" approach for setting the income tax component of revenue requirements in this case, the Commission provide now for recovery of taxes when the circumstances giving rise to the Order have been resolved. Petition for Reconsideration at 43. We understand the concern that the consolidated effective tax rate will likely increase at some point in the future. However, we are concerned that the Companies have not suggested the mechanism for future rate adjustment that they would like us to consider and therefore the CAD, Staff and other interested parties have not had an opportunity to comment on the reasonableness of such a mechanism. We are also concerned that the establishment of automatic adjustment procedures when a single element of revenue requirements changes is a significant departure from traditional prospective overall cost-of-service ratemaking that must be carefully and fully considered. We simply do not believe that the establishment of such a procedure for the income tax component of rates has been fully and properly placed on the record in this proceeding. In addition, the Companies should be able to monitor the consolidated tax status of the Allegheny Power Consolidated Tax Group on an annual, semi-annual or even quarterly basis and should be in a position to quickly file a full rate case at such time as they believe they can present evidence that there will be a positive effective income tax rate for the consolidated group on a going forward basis. Looking at income taxes in a full rate case where multiple elements of the Companies' revenue

requirements may be changing over time, some in opposite directions, is preferable to attempting to design a special mechanism that may provide an advantage for the Companies but disadvantage other parties. This is particularly true considering the lack of opportunity for input from all parties on the procedures for such a special mechanism.

B. Accumulated Deferred Income Taxes

In the Original Rate Order, the Commission determined that certain future tax liabilities that would be incurred related to certain generation assets of Potomac Edison should be offset by ADITS. We further determined that the ADITS should be treated as a rate base offset until they were fully amortized. *See*, Original Rate Order at 33-35. The Companies petitioned for reconsideration of the Commission decision with regard to the ADITS.

1. Arguments of the Companies

The Companies disagree with the appropriateness of any rate base adjustment for ADITS related to the Asset Swap. The Companies argue that the Commission decision is based solely on a recommendation made by CAD witness Majoros, which the witness later agreed was a mistake. The Companies further argue that the Commission decision was based on the erroneous notion that the Potomac Edison generation assets that had been transferred to an affiliate company in 2000 were the identical assets that were transferred back to Potomac Edison in 2007. *See generally*, Petition for Reconsideration at 45-50.

Although they disagree with any adjustment, the Companies also point out that the Commission ADITS rate base offset was intended to be equal to the amount of additional future income tax liability which they had presented as their adjustment number 31. Although this amount was originally \$22.8 million, it was later adjusted by the Companies but the Commission failed to reflect that adjustment in our final ADITS rate base offset. As explained by the Companies:

The [Commission's] ADIT rate base adjustment of \$22,797,000 on the line labeled 'Deferred Tax on PE Asset Adjustment' was based on the Companies' *original* estimate of tax liability; based on the Order, the ADIT rate base adjustment should have been \$17,851,982, *i.e.*, the updated total additional deferred tax liability of \$18,472,375, less one year of amortization at \$630,693. *See* Order at 33; see also CAD Initial Br. at 20. The \$11,311,000 reduction to rate base indicated on the line labeled 'Update for Swap' correctly reflects the change in net plant from the estimated amounts in the original filing to the final accounting entries for the Asset Swap, but the tax effect of that reduction is not reflected. Accordingly, the Companies request a correction to increase rate base by \$4,945,018, *i.e.*, the difference between the original estimate of \$22,797,000 and the \$17,851,982 rate base adjustment called for in the Order.

2. Responses to Companies Arguments

The CAD was the only party to respond to the arguments of the Companies with regard to the ADITS issue. The CAD opposed the arguments of the Companies and supported the decision of the Commission on this issue. CAD Response at 18-22. However, the CAD indicated that it believed that the Companies are correct in alleging that a smaller amount of ADIT, based on the updated actual value of the transferred assets, should be used in making this adjustment. CAD Response at 22.

3. Commission Decision

The Commission will not change its decision to include an appropriate amount of ADITS, equal to the amount of future income tax liability resulting from the asset swap that returned generation assets to Potomac Edison. The Companies are incorrect that the Commission decision was based on testimony of CAD witness Majoros that was later recanted, or upon a finding that the exact generation assets that had been transferred from Potomac Edison to an affiliate in 2000 were returned to Potomac Edison as part of the asset swap in 2007. The Original Rate Order fully explained that the purpose of this adjustment was to reflect ADITS sufficient to offset the future income tax liability related to the generation asset transfer identified by the Companies as follows:

The Commission finds that the 'relationship' that the Companies contend is missing between the ADITS that were 'transferred out of regulation' and the ratemaking offset proposed by the CAD actually does exist. We view the CAD's proposal as nothing more than recreating a deferred credit comparable to the transferred ADITS to serve the same purpose as the transferred ADITS albeit at a different amount. The accumulated deferred tax credits were available to pay future income tax liability related to differences between book and tax depreciation. While they remained on the utility's balance sheet, they were used as a rate base offset for ratemaking purposes. Here, the Companies have identified a comparable future tax liability, but at a greatly reduced amount of \$18.5 million. We believe that it is fair and reasonable to restore a deferred credit for ratemaking purposes equal to the amount that is now necessary to cover this future tax liability. We do not find this to be irrational or unrelated to the intent and reality of the original ADITS.

Original Rate Order at 35. The Commission intended to create a rate base offset equal to the adjusted true-up amount that had been filed by the Company. However, we erroneously used the original estimate of \$22.8 million in our rate base calculation. We shall adjust that rate base offset to \$17.9 million as requested by the Companies.

C. Depreciation Rates

The Commission approved depreciation rates for the Companies that did not include the net cost of removal estimates included in the calculations provided by the Companies of their depreciation rates. *See generally*, Original Rate Order at 23-28. The CAD had recommended that the balances provided by the Companies for accumulated depreciation were overstated and that the excess accumulated depreciation should be amortized over a five-year period and credited to annual expenses. The Commission did not adopt this recommendation of the CAD. Instead, the Commission based new depreciation rates on the net plant balances which reflected the excess accumulated depreciation, resulting in lower, and in some cases negative, depreciation rates.

1. *Arguments of the Companies*

The Companies argued that it was an error for the Commission to adopt the Staff recommended depreciation rates because Staff had erred in neglecting to remove the cost of removal reserve from the book reserve prior to calculating the life rate. Petition for Reconsideration at 50. The Companies opined that the effect of this error was to not only completely remove the net negative salvage from the rate as intended, but also to unintentionally remove part or, in some cases, all of the life portion of the rate. The Companies further argued that the error is evidenced by several negative depreciation rates in Appendix A: e.g. Willow Island Unit 1 (-0.03%), Albright Unit 2 (-0.58%), Albright Unit 3 (-0.21%), Pleasants Unit 1 Scrubber (-0.15%), Harrison Unit 2 (-0.49%), and Harrison Unit 3 (-0.30). *Id.* at 51.

The Companies noted that CAD witness Majoros also accepted the remaining lives proposed by the Companies and excluded the negative salvage component from the rates proposed by the Companies, but came up with higher rates than Staff because Mr. Majoros eliminated the cost of removal reserve from the book reserve before calculating the life-only depreciation rate. *Id.*

2. *Responses to Companies Arguments*

The CAD and Staff responded to the Petition for Reconsideration on this issue and supported the Commission ordered depreciation rates. CAD Response at 22; Staff Response at 12. The CAD noted that the cost of removal reserve represents depreciation expense previously collected from ratepayers. Elimination of this reserve ignores these amounts previously paid by ratepayers and adds the dollar value of the cost of removal reserve back into plant remaining in service. This results in higher annual depreciation accruals and depreciation expense. CAD Response at 23. CAD further admitted that its witness, Mr. Majoros, removed the cost of removal reserve before calculating his proposed depreciation accrual rates. However, this was consistent with the companion recommendation by Mr. Majoros that the excess cost of removal reserve be amortized over a five-year period. *Id.* Although different than the CAD proposed depreciation rates, the CAD argued that Staff depreciation rates are correct given the treatment by the Commission of the cost of removal reserve. *Id.*

Staff similarly argued that its proposed depreciation rates were correct and it was correct for the Commission to adopt those rates. Staff pointed out that its calculations do reflect the removal of the future cost of removal proposed by the Companies. However, Staff further pointed out that the rates which it calculated will eventually, over the remaining lives of the assets, make the correction for the over-accrued cost of removal included in the accumulated depreciation balances. Staff Response at 13-14.

3. Commission Decision

The Companies are incorrect in their argument that there is any error in including the excess cost of removal reserves when calculating the depreciation rate. As we explained in our Original Rate Order:

[T]o the extent that prior depreciation rates have over-accrued depreciation reserves, such over-accrual will be reflected in future depreciation rates, which will benefit the customers in the form of lower annual depreciation expenses. In the meantime as any over-accrual is reduced through application of new depreciation rates, ratepayers would continue to receive the benefit of a reduced rate base reflecting the depreciation rates used in the past.

Original Rate Order at 27-8. If we adopted the position of the Companies, over-accruals in the past would not be reflected in future depreciation rates and would remain permanently embedded in reserves for depreciation.

The argument that negative depreciation rates prove that there is an error in the Commission approved depreciation rates is incorrect. If past depreciation rates have resulted in the accumulation of depreciation reserves that exceed the gross cost of plant and reasonable net salvage value (positive or negative), then a negative going-forward depreciation rate is necessary.

The Commission finds that the cost of removal amounts embedded in the Companies reserves for depreciation are excessive. We correct for this by excluding the cost of removal from any calculation of future depreciation rates, but establish the appropriate future reserve target by continuing to include the amounts already embedded in the reserves when calculating the necessary future depreciation rates. This is the method adopted in our Original Rate Order and we shall not modify the depreciation rates approved in that decision.

D. Variable Pay Plan

In the Original Rate Order, the Commission allowed certain bonuses pursuant to a "variable pay plan" to be included in revenue requirements, over the objection of the CAD and Staff. Original Rate Order at 15-17. The Commission did so after noting that the Companies did not demonstrate that they included responsiveness to customers as a criterion for bonuses. *Id.* at 17. The Commission conditioned the allowance upon the

Companies including a customer responsiveness aspect in their variable pay plan that placed a strong but balanced emphasis on customer service and responsiveness, in relation to the other performance indicators. The Commission required that a variable pay plan that included such criteria be filed for Staff review no later than September 30, 2007. Id.

1. Arguments of the Companies

The Companies argued that the Commission should rescind its directive to submit for Staff review the variable pay plan, which must include a customer responsiveness aspect. Petition for Reconsideration at 52-5. The Companies indicated that customer responsiveness is, in fact, specifically addressed through their management of individual employees. Citing *United Fuel Gas Co. v. Public Serv. Comm'n*, 154 W. Va. 22 1, 174 S.E.2d 304 (1970), the Companies suggest that the Commission is inappropriately attempting to manage them. Petition for Reconsideration at 54-5. The Companies seem to equate the conditional allowance of an expense that both the CAD and Staff urged the Commission to disallow completely as an attempt by the Commission to "manage" rather than regulate. The Companies concede that distinguishing appropriate regulation from inappropriate invasion of management prerogatives can sometimes be difficult, but the Companies argue that a directive to include a specific criterion in an employee compensation program crosses that line. Id. at 55.

2. Responses to Companies Arguments

The CAD disagreed with the petition of the Companies. CAD Response at 24-7. The CAD argued that the Commission reasonably conditioned the allowance of a variable pay plan upon certain criteria that would assure that the plan was reasonably balanced and included customer interests as well as stockholder interests as factors to be considered before employees were rewarded with additional pay.

The Consumer Advocate Division agrees that the Commission is not a 'super board of directors.' The management of any utility should be left in the first instance to the utility's management. However, the Commission may regulate not only the practices of utilities, but also the cost recovery of utilities through the establishment of rates. Expenses related to unreasonable or questionable programs may be disallowed for ratemaking purposes.

CAD Response at 25. The CAD argued that both it and Staff had challenged the variable pay plan on various grounds. It further pointed out:

In Allegheny's last rate case, incentive compensation was removed from cost of service. The Chief Administrative Law Judge stated: ' . . .these bonuses are, in fact, shareholder-oriented and have little to do with performance measures and goals affecting the ratepayers, except in an ancillary fashion.' *Monongahela Power Co.*, Case No. 94-0035-E-42T,

"Recommended Decision" (Sept. 30, 1994), p. 69. The Commission reversed that decision in this case based on the condition that the Companies include plan criteria related to customer service and responsiveness.

CAD Response at 27.

3. *Commission Decision*

The Commission does not agree with the Companies that it has usurped the role of management, contrary to the directive of the Supreme Court of West Virginia as set forth in *United Fuel*. In that case, the Commission was not making a determination with regard to the reasonableness of an expense item to include in a rate case. The role of management discussed in the *United Fuel* case arose in the context of a management decision to reorganize or realign its corporate structure. In the present case, the Commission found that the arguments of the CAD and Staff for disallowing bonuses under a variable pay plan that benefitted only stockholders should be rejected as long as the challenged variable pay plan considered interests of customers as well as stockholders. Effectively, the Commission determined that bonuses that rewarded employees for benefitting stockholders but did not consider customer satisfaction and service would not be reasonable. Because it was unconvinced that the Companies had demonstrated that the variable pay plan adequately considered the interests and needs of customers, the Commission established a condition for the allowance of the costs of the variable pay plan in customer rates in this case. Original Rate Order at 16-7. The alternative would have been to disallow the bonuses under the variable pay plan altogether, as had been urged by the CAD and Staff. We do not believe that such a disallowance could be viewed as anything other than an appropriate action by the Commission pursuant to its statutory authority to set just and reasonable rates based on costs. In other words, if rates are based on costs that are not reasonable, then the rates themselves cannot be said to be just and reasonable.

The Commission continues to believe that bonuses paid to employees should be based on a variety of factors. Some of those factors may directly or indirectly consider the interests of stockholders. Likewise, some of those factors must directly or indirectly consider the interests of customers. The Commission has determined that a component of customer interest is responsiveness to customers. This responsiveness may be measured and evaluated in any number of ways. The Commission is not, at this time, dictating how such responsiveness may be measured and evaluated. Neither are we interjecting ourselves into the management of individual employees to determine if they meet reasonable goals and objectives which include a customer related component.

Upon reconsideration, we see that requiring the Companies to submit for Staff review a variable pay plan that includes a customer related component could be viewed as requiring Staff take on the role of management. We did not intend that result. Our intention was to establish a broad condition for a customer responsiveness and service component of a variable pay plan and require that such a plan be filed as part of the

record in this case so that it would be available for review by all parties and the Commission. Accordingly, we shall modify the condition established in the Original Rate Order to require that the Companies revise the variable pay plan to include a customer responsiveness aspect and submit such pay plan to the Office of the Secretary for inclusion in the case file in this proceeding no later than ninety days from the date of this Order. A strong but balanced emphasis should be placed on customer service and responsiveness, in relation to the other performance indicators, in the revised variable pay plan. The revised plan shall be available for review and shall be considered in the next rate case file by the Companies, or sooner if necessary.

E. Right-of-Way Maintenance

The Commission allowed an additional \$4.3 million for right-of-way maintenance costs to be included in the Companies' revenue requirements in this case. The allowance of this additional amount departed from the traditional "known and measurable" criteria for expense adjustments and was opposed by Staff. The CAD did not oppose the adjustment as long as a tracking and true-up mechanism was established. The Companies agreed to a tracking and true-up mechanism. Original Rate Order at 13-5.

1. Arguments of the Companies

The Companies requested that the Commission modify its decision but only with regard to the timing of the first "annual" tracking proceeding. The Companies suggested that the first annual reconciliation period extend from May 23, 2007, through May 31, 2008, and that the increment for, that first period be \$4,394,247, to reflect an additional eight days. Subsequent periods would run each year from June 1 through May 31. Petition for Reconsideration at 52.

2. Responses to Companies Arguments

The CAD responded that an easier approach to this issue is to make the right-of-way maintenance reconciliation annual periods be the same as the review periods in the ENEC proceedings for the Companies. CAD Response at 23-4. Under such a schedule, the first annual period would run from May 23, 2007, to June 30, 2008, and subsequent reconciliation periods would run from July 1 to June 30 of each year, the same time frame as the ENEC review period. In its response, the CAD represented that it had presented its proposed schedule for review of right-of-way maintenance expenses to the Companies and is authorized to represent that the Companies have no objection to its adoption by the Commission. CAD Response at 24.

3. Commission Decision

The Commission agrees that the first reconciliation period should run from the date that rates in this case went into effect, May 23, 2007, to June 30, 2008. We note that the first ENEC has already been filed and the right-of-way reconciliation data through June 30, 2008 was included in that filing. *See, Monongahela Power Co. and the Potomac*

Edison Co., Case No. 08-1511-E-GI. We shall consider the right-of-way maintenance expenditures for that period in the current ENEC proceeding and shall hereafter track the right-of-way maintenance expenditures for annual periods running from July 1 through June 30. In all other respects regarding tracking and true-up for this additional expense allowance, the Original Rate Order shall remain in effect.

The Original Rate Order contained findings of fact and conclusions of law relating to arguments in the Petition for Reconsideration. Those findings of fact and conclusions of law will not be repeated herein, but will remain in full force and effect except as modified by this Order.

FINDINGS OF FACT

1. The Companies filed a Petition for Reconsideration on June 15, 2007.
2. Staff, CAD, and WVEUG filed responses to the Petition for Reconsideration.
3. The Commission determines that it should have used \$17.9 million as a rate base offset instead of \$22.8 million.
4. Right-of-way maintenance expenses for the Companies are currently being considered in Case No. 08-1511-E-GI for the reconciliation period of May 23, 2007, to June 30, 2008.

CONCLUSIONS OF LAW

1. To be included as an expense in base rate calculation, a variable pay plan should benefit the customers of the utility as well as the shareholders. By requiring the Companies to file a revised variable pay plan, the Commission is not usurping the management role of the Companies. Rather, the Commission is ensuring that this expense is a reasonable cost that should be included for ratemaking purposes.
2. It is reasonable to adjust rates to reflect a rate base offset of \$17.9 million instead of \$22.8 million used in the Original Rate Order.
3. Future right-of-way maintenance expenses shall be tracked for annual periods running from July 1 through June 30.
4. Except as noted herein, this Order does not replace the Original Rate Order, but acts to further clarify the Commission decisions in this case.

ORDER

IT IS THEREFORE ORDERED that the Petition for Reconsideration and Clarification and Application for Further Hearing is hereby denied except as follows:

1) Regarding the inclusion of accumulated deferred income taxes when calculating base rates, the Commission erroneously used the original estimate of \$22.8 million. The Commission shall adjust that rate base offset to \$17.9 million as requested by the Companies. The corrected tariff rates which reflect a return on the additional rate base are attached hereto as Appendix A;

2) The Companies shall file in this case a revised variable pay plan, including a component for responsiveness to customers, within ninety days of the date of this Order. The revised plan shall be available for review and shall be considered in the next rate case file by the Companies, or sooner if necessary; and

3) The Commission clarifies that right-of-way maintenance expenses shall be considered in ENEC proceedings filed by the Companies with the first reconciliation period running from the date that rates in this case went into effect, May 23, 2007, to June 30, 2008, as has already occurred in Case No. 08-1511-E-GI. The Commission shall hereafter track the right-of-way maintenance expenditures for annual periods running from July 1 through June 30.

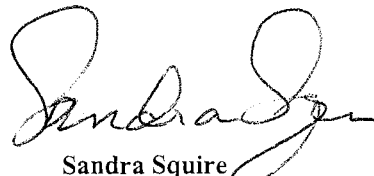
IT IS FURTHER ORDERED that, except as modified herein, the Commission order entered on May 22, 2007 shall remain the final order in this case.

IT IS FURTHER ORDERED that upon entry of this order this case shall be removed from the Commission docket of open cases.

IT IS FURTHER ORDERED that the Commission Executive Secretary serve a copy of this Order upon all parties of record by United States First Class Mail and upon Commission Staff by hand delivery.

Commissioner Albert has recused himself from these cases.

A True Copy, Teste:



Sandra Squire
Executive Secretary

SMS/slc
060960cg

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedules A & R

Customer Charge	4.00
Energy Charge (kWh)	0.06546

The above energy rate includes an embedded fuel charge of \$.02526 per kWh sold.

Rate Schedules B & G

Customer Charge	4.00
Minimum kW	2.41
Energy Charge (kWh)	
First Block (0-400)	0.07979
Second Block (over 400)	0.06945

The above energy rates include an embedded fuel charge of \$.02632 per kWh sold.

Rate Schedules C & E

Customer Charge	31.51
Minimum kW	3.15
Demand Charge	7.34
Energy Charge (kWh)	0.03310

The above energy rate includes an embedded fuel charge of \$.02482 per kWh sold.

Voltage Discount	(0.25)

Rate Schedules CSH & CSH

Energy Charge (kWh)	0.06107

The above energy rate includes an embedded fuel charge of \$.02469 per kWh sold.

Rate Schedules D & PH

Demand Charge (kW)	
Minimum kW	2.70
First Block (0-500)	11.46
Second Block (over 500)	10.25

The above demand rates include an embedded fuel charge of \$.95 per kW sold.

Energy Charge (kWh)	0.02328

The above energy rate includes an embedded fuel charge of \$.02294 per kWh sold.

RkVA Charge	0.40
Voltage Discount	(0.25)

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedules K & PP

Demand Charge (kVA)

First Block (0-1,000) 6.645

Second Block (over 1,000) 5.625

The above demand rates include an embedded fuel charge of \$.96 per kVA sold.

Energy Charge (kWh) 0.02630

The above energy rate includes an embedded fuel charge of \$.02347 per kWh sold.

Line Voltage Charge 0.40

Rate Schedules P & LP

Demand Charge (kVA)

First Block (0-3,000) 7.177

Second Block (3,001-17,000) 6.763

Third Block (over 17,000) 6.450

The above demand rates include an embedded fuel charge of \$.85 per kVA sold.

Energy Charge (kWh) 0.02288

The above energy rate includes an embedded fuel charge of \$.01882 per kWh sold.

Rate Schedule AGS - MP & PE

Demand Charge (kW)

0-15 kV Service

Firm Standby Power

First Block (0-100) 5.620

Second Block (over 100) 4.666

Interruptible Standby Power

First Block (0-100) 5.369

Second Block (over 100) 4.416

Maintenance Power

All kW 4.416

15-100 kV Service

Firm Standby Power

First Block (0-100) 3.949

Second Block (over 100) 2.995

Interruptible Standby Power

First Block (0-100) 3.698

Second Block (over 100) 2.744

Maintenance Power

All kW 2.744

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule AGS - MP & PE (Continued)

Over 100 kV Service	
Firm Standby Power	
First Block (0-100)	3.124
Second Block (over 100)	2.170
Interruptible Standby Power	
First Block (0-100)	2.873
Second Block (over 100)	1.919
Maintenance Power	
All kW	1.919

The above demand rates include an embedded fuel charge of \$.020 per kVA sold.

Energy Charge (kWh)	0.04402

The above energy rate includes an embedded fuel charge of \$.03902 per kWh sold.

RkVA Charge	0.40

Rate Schedule SL-P- MP

Sodium Vapor - Semi-Enclosed	
9,500 Lumen (100 Watt)	6.58
Sodium Vapor - Standard Enclosed Type	
9,500 Lumen (100 Watt)	7.17
22,000 Lumen (200 Watt)	10.10
50,000 Lumen (400 Watt)	15.17
Sodium Vapor - Floodlight	
22,000 Lumen (200 Watt)	10.10
50,000 Lumen (400 Watt)	15.17
Sodium Vapor - Pole Top Mounted	
9,500 Lumen (100 Watt)	13.02
Mercury Vapor	
8,150 Lumen (175 Watt)	8.22
11,500 Lumen (250 Watt)	9.86
21,500 Lumen (400 Watt)	12.92
60,000 Lumen (1,000 Watt)	22.44
Floodlights	
11,500 Lumen (250 Watt)	9.86
21,500 Lumen (400 Watt)	12.92
60,000 Lumen (1,000 Watt)	22.44
Pole-Top Mounted, 8,150 Lumen (175 Watt) M.V.	
15' Steel Pole	14.67
20' Steel Pole	15.86
14' Aluminum Pole	14.72
Spans	0.60
Poles	1.29

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule SL-P- MP (Continued)

8,150 Lumen with 8' Arm	0.23
8,150; 11,500; 21,500; 60,000 Lumen with 10' Arm	0.57
with 12' Arm	0.75
with 15' Arm	0.90

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule MV - MP

Standard Semi-Enclosed	
8,150 Lumen (175 Watt)	8.22
Standard Enclosed	
11,500 Lumen (250 Watt)	9.86
21,500 Lumen (400 Watt)	12.92
60,000 Lumen (1,000 Watt)	22.44
Floodlights	
11,500 Lumen (250 Watt)	9.86
21,500 Lumen (400 Watt)	12.92
60,000 Lumen (1,000 Watt)	22.44
Pole-Top	
8,150 Lumen (175 Watt)	14.72
8,150 Lumen with 8' Arm	0.23
8,150; 11,500; 21,500; 60,000 Lumen with 10' Arm	0.57
with 12' Arm	0.75
with 15' Arm	0.90

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule SV - MP

Sodium Vapor - Semi-Enclosed	
9,500 Lumen (100 Watt)	6.58
Sodium Vapor - Standard Enclosed Type	
9,500 Lumen (100 Watt)	7.17
22,000 Lumen (200 Watt)	10.10
50,000 Lumen (400 Watt)	15.17
Sodium Vapor - Floodlight	
22,000 Lumen (200 Watt)	10.10
50,000 Lumen (400 Watt)	15.17
Sodium Vapor - Pole Top Mounted	
9,500 Lumen (100 Watt)	13.02

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

**MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D**

Rate Schedule EMU - MP & PE

OVERHEAD SERVICE

HPS-Vertical Open Lens Luminaire/OL

9,500 Lumen(100 Watt)	
With Pole	15.08
9,500 Lumen(100 Watt)	
Without Pole	6.58

MV-Horizontal /Cobra Head

8,150 Lumen(175 Watt)	8.22

HPS-Horizontal/Cobra Head

9,500 Lumen(100 Watt)	7.17
22,000 Lumen(200 Watt)	10.10
50,000 Lumen(400 Watt)	15.17

MH-Horizontal/Cobra Head

36,000 Lumen(400 Watt)	17.65
90,000 Lumen(1000 Watt)	33.07

HPS Floodlight

22,000 Lumen(200 Watt)	10.10
50,000 Lumen(400 Watt)	15.17

MH Floodlight

36,000 Lumen(400 Watt)	17.65
90,000 Lumen(1000 Watt)	33.07

UNDERGROUND SERVICE

HPS Colonial Post Top 14' Mounting Hgt

9,500 Lumen(100 Watt)	13.02

MH Colonial Post Top 14' Mounting Hgt

11,600 Lumen(175 Watt)	17.21

HPS Cobra Head/30' Mounting Hgt

Single Luminaire Per Pole:

9,500 Lumen(100 Watt)	20.97
22,000 Lumen(200 Watt)	23.90
50,000 Lumen(400 Watt)	28.96

Each Add'l Luminaire Per Pole:

9,500 Lumen(100 Watt)	7.17
22,000 Lumen(200 Watt)	10.10
50,000 Lumen(400 Watt)	15.17

MH Horizontal Cobra Head/30' Mounting Hgt

Single Luminaire Per Pole:

36,000 Lumen(400 Watt)	31.44
90,000 Lumen(1000 Watt)	46.87

Each Add'l Luminaire Per Pole:

36,000 Lumen(400 Watt)	17.65
90,000 Lumen(1000 Watt)	33.07

HPS-Shoe Box/30' Mounting Hgt

With Base:

9,500 Lumen(100 Watt)	29.78

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule EMU - MP & PE (Continued)

22,000 Lumen(200 Watt)	31.54
50,000 Lumen(400 Watt)	35.12
No Base:	
9,500 Lumen(100 Watt)	23.62
22,000 Lumen(200 Watt)	25.38
50,000 Lumen(400 Watt)	28.97
Each Addt'l Luminaire Per Pole:	
9,500 Lumen(100 Watt)	13.35
22,000 Lumen(200 Watt)	15.11
50,000 Lumen(400 Watt)	18.70
MH Shoe Box/30' Mounting Hgt	
With Base:	
36,000 Lumen(400 Watt)	37.18
No Base:	
36,000 Lumen(400 Watt)	31.03
Each Addt'l Luminaire Per Pole:	
36,000 Lumen(400 Watt)	20.76
MH Shoe Box/40' Mounting Hgt	
No Base:	
90,000 Lumen(1000 Watt)	51.29
Each Addt'l Luminaire Per Pole:	
90,000 Lumen(1000 Watt)	37.14

Long Term Service having an initial term of ten (10) years is available and monthly rate as set forth in this schedule shall be reduced by fifty cents per lamp. After the initial term, the Agreement shall remain in effect until canceled by either party with not less than ninety (90) days prior written notice of cancellation.

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule MU - MP & PE

HPS Vapor

Customer Owned Pole:	
9,500 Lumen(100 Watt)	4.36
22,000 Lumen(200 Watt)	6.00
50,000 Lumen(400 Watt)	9.77
Company Distr. System:	
9,500 Lumen(100 Watt)	5.33
22,000 Lumen(200 Watt)	6.97
50,000 Lumen(400 Watt)	10.74

Mercury Vapor

Customer Owned Pole:	
8,150 Lumen(175 Watt)	5.34
11,500 Lumen(250 Watt)	6.75
21,500 Lumen(400 Watt)	8.65

**MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D**

Rate Schedule MU - MP & PE (Continued)

60,000 Lumen(1000 Watt)	18.09
Company Distr. System:	
8,150 Lumen(175 Watt)	6.32
11,500 Lumen(250 Watt)	7.72
21,500 Lumen(400 Watt)	9.61
60,000 Lumen(1000 Watt)	19.06
Metal Halide	
Customer Owned Pole:	
11,600 Lumen(175 Watt)	6.49
15,000 Lumen(250 Watt)	8.02
36,000 Lumen(400 Watt)	10.46
90,000 Lumen(1000 Watt)	21.78
Company Distr. System:	
11,600 Lumen(175 Watt)	7.46
15,000 Lumen(250 Watt)	8.99
36,000 Lumen(400 Watt)	11.43
90,000 Lumen(1000 Watt)	22.75
Incandescent	
Customer Owned Pole:	
1,000 Lumen(100 Watt)	4.87
2,500 Lumen(200 Watt)	6.48
4,000 Lumen(325 Watt)	8.65
6,000 Lumen(450 Watt)	10.74
Company Distr. System:	
1,000 Lumen(100 Watt)	5.84
2,500 Lumen(200 Watt)	7.45
4,000 Lumen(325 Watt)	9.62
6,000 Lumen(450 Watt)	11.71

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule EM - MP & PE

OVERHEAD SERVICE

MV Horizontal Cobra Head

8,150 Lumen(175 Watt)	5.44

HPS Horizontal Cobra Head

9,500 Lumen(100 Watt)	5.73
22,000 Lumen(200 Watt)	6.56
50,000 Lumen(400 Watt)	7.80

MH Horizontal Cobra Head

36,000 Lumen(400 Watt)	8.97
90,000 Lumen(1000 Watt)	14.01

HPS Floodlight

22,000 Lumen(200 Watt)	6.56
50,000 Lumen(400 Watt)	7.80

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule EM - MP & PE (Continued)

MH Floodlight	
36,000 Lumen(400 Watt)	8.97
90,000 Lumen(1000 Watt)	14.01
UNDERGROUND SERVICE	
MH Colonial Post Top/14' Mounting Hgt	
11,600 Lumen(175 Watt)	12.51
HPS Horizontal Cobra Head/30' Mtg Hgt	
Single Luminaire Per Pole:	
9,500 Lumen(100 Watt)	19.53
22,000 Lumen(200 Watt)	20.36
50,000 Lumen(400 Watt)	21.60
Each Addt'l Luminaire Per Pole:	
9,500 Lumen(100 Watt)	5.73
22,000 Lumen(200 Watt)	6.56
50,000 Lumen(400 Watt)	7.80
MH Horizontal Cobra Head/30' Mtg Hgt	
Single Luminaire Per Pole:	
36,500 Lumen(400 Watt)	22.77
90,000 Lumen(1000 Watt)	27.80
Each Addt'l Luminaire Per Pole:	
36,500 Lumen(400 Watt)	8.97
90,000 Lumen(1000 Watt)	14.01
HPS Shoe Box/30' Mounting Hgt	
Single Luminaire Per Pole w/base:	
9,500 Lumen(100 Watt)	26.20
22,000 Lumen(200 Watt)	26.55
50,000 Lumen(400 Watt)	26.59
No Base:	
9,500 Lumen(100 Watt)	20.05
22,000 Lumen(200 Watt)	20.39
50,000 Lumen(400 Watt)	20.43
Each Addt'l Luminaire Per Pole:	
9,500 Lumen(100 Watt)	9.77
22,000 Lumen(200 Watt)	10.11
50,000 Lumen(400 Watt)	10.15
MH Shoe Box/30' Mounting Hgt	
With Base:	
36,000 Lumen(400 Watt)	28.56
No Base:	
36,000 Lumen(400 Watt)	22.41
Each Addt'l Luminaire Per Pole:	
36,000 Lumen(400 Watt)	12.13
MH Shoe Box/40' Mounting Hgt	
No Base:	
90,000 Lumen(1000 Watt)	31.77

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule EM - MP & PE (Continued)

Each Addtl Luminaire Per Pole:

90,000 Lumen(1000 Watt) 17.63

Long Term Service having an initial term of ten (10) years is available and monthly rate as set forth in this schedule shall be reduced by fifty cents per lamp. After the initial term, the Agreement shall remain in effect until canceled by either party with not less than ninety (90) days prior written notice of cancellation. Municipal lighting service is typically provided under Long term agreement for initial and supplemental installation.

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule LIT - MP

Mercury Vapor

3,300	9.56
7,000	10.33
11,000	11.45
20,000	15.06
53,000	27.94

Sodium Vapor

5,000	12.18
8,000	12.51
14,000	14.09
23,000	18.33
42,000	22.70
127,000	34.99

Ultra Style-Rect. Shaped luminaries

Sodium Vapor-1st Unit p/pole

5,000	26.59
8,000	26.89
14,000	26.99
23,000	28.97
42,000	30.39

Sodium Vapor-Each Additional Unit Same Pole

5,000	10.70
8,000	10.85
14,000	11.48
23,000	15.40
42,000	16.93

Urbanlites - Rect. Shaped luminaries

Mercury Vapor

20,000	27.27

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule LIT - MP (Continued)

Sodium Vapor		
	14,000	26.48
	23,000	28.04
	42,000	30.11
Directional Lighting Service		
Mercury Vapor		
	20,000	18.63
	53,000	30.46
Each Additional Same Pole		
	20,000	13.74
	53,000	21.13
Sodium Vapor		
	42,000	26.89
	127,000	35.01
Each Additional Same Pole		
	42,000	17.58
	127,000	24.79

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule OL - PE

High Pressure Sodium	
9,500 Lumen	6.58
22,000 Lumen	10.10
Mercury Vapor	
8,150 Lumen	8.22
21,500 Lumen	12.92
Std Wood Pole	1.53
Wire	0.01
Transformer Capacity	1.53

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule AL - PE

Floodlighting	
Mercury Vapor	
21,500 L (400 w)	12.92
60,000 L (1000 w)	22.44
High Pressure Sodium	
50,000 L (400 w)	15.17
Quartz Iodine	13.90
Poles - wood	
30 foot	1.53
35 foot	2.12
40 foot	2.28

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule AL - PE (Continued)

Wire	0.01
Customer Owned Equipment	
Mercury Vapor	
400 W	8.65
1,000 W	18.09

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule MSL - PE

High Pressure Sodium	
Overhead Supply - Wood Pole	
5,800 Lumen	6.61
9,500 Lumen	7.17
22,000 Lumen	10.10
50,000 Lumen	15.17
Overhead Supply - Metal Pole	
50,000 Lumen	28.96
Underground Supply - Standard Pole	
Low mount	
5,800 Lumen	12.45
9,500 Lumen	13.02
High mount	
5,800 Lumen	20.21
9,500 Lumen	20.97
22,000 Lumen	23.90
50,000 Lumen	28.96
Customer Owned Equipment	
5,800 Lumen	3.72
9,500 Lumen	4.36
22,000 Lumen	6.00
50,000 Lumen	9.77
Rectangular Enclosed Underground	
High Mount	
9,500 Lumen	29.78
22,000 Lumen	31.54
50,000 Lumen	35.12
Multiple Units	
9,500 Lumen	13.35
22,000 Lumen	15.11
50,000 Lumen	18.70
Mercury Vapor	
Overhead Supply - Wood Pole	
8,150 Lumen	8.22
11,500 Lumen	9.86

MONONGAHELA POWER COMPANY & THE POTOMAC EDISON COMPANY
COMMISSION ORDERED RATES
CASE NOS. 06-0960-E-42T AND 06-1426-E-D

Rate Schedule MSL - PE (Continued)

21,500 Lumen	12.92
Overhead Supply - Metal Pole	
21,500 Lumen	18.68
Underground Supply	
Low Mount	
8,150 Lumen	10.84
High Mount	
11,500 Lumen	12.67
21,500 Lumen	18.68
Continuous Burn	
Overhead Supply - Wood Pole	
11,500 Lumen	15.65
Overhead wire	0.01
Underground wire	0.01

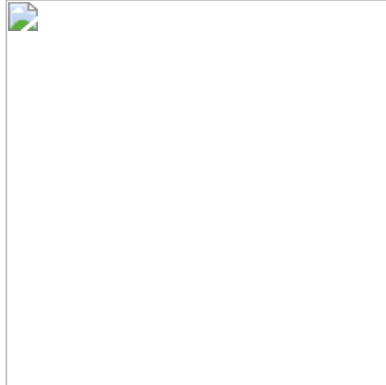
The above rates include an embedded fuel charge of \$.02421 per kWh sold.

Rate Schedule SL - PE

Mast Arm, Bkt, or CS	
1,000 Lumen	2.75
2,500 Lumen	4.04
4,000 Lumen	5.23
Orn. or White Way Overhead	
4,000 Lumen	5.68
6,000 Lumen	6.91
10,000 Lumen	9.88
White Way Underground	
6,000 Lumen	8.03

The above rates include an embedded fuel charge of \$.02421 per kWh sold.

BEFORE THE PUBLIC SERVICE COMMISSION



OF THE STATE OF MISSOURI

In the Matter of Laclede Gas Company's Tariff)
to Revise Natural Gas Rate Schedules.

Case No. GR-99-315
)

THIRD REPORT AND ORDER

Issue Date: January 11, 2005

Effective Date: January 21, 2005

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Laclede Gas Company's Tariff)
to Revise Natural Gas Rate Schedules.

Case No. GR-99-315
)

Table of Contents

Appearances.....	1

Overview	
2	
Procedural History	3
Pending Motions.....	4
Findings of Fact	6
Summary	16
Conclusions of Law	17
Jurisdiction.....	17
Burden of Proof.....	17
Mootness	18
Accounting Adjustments.....	19
Ordered Paragraphs	20

APPEARANCES

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and

Thomas M. Byrne, Associate General Counsel, Ameren Services Company, One Ameren Plaza, 1901 Chouteau Avenue, Post Office Box 66149 (MC 1310), St. Louis, Missouri 63166-6149, for Union Electric Company d/b/a AmerenUE.

M. Ruth O'Neill, Senior Public Counsel, Office of the Public Counsel, 200 Madison Street, Suite 650, Post Office Box 2230, Jefferson City, Missouri 65102, for the Office of the Public Counsel and the public.

Thomas R. Schwarz, Jr., Deputy General Counsel, Missouri Public Service Commission, 200 Madison Street, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

REGULATORY LAW JUDGE: **Nancy Dippell, Senior Regulatory Law Judge.**

THIRD REPORT AND ORDER

Syllabus: This order finds that the accrual method should be used to calculate Laclede's net salvage value and that Laclede should establish a separate account on its books for tracking these expenditures and collections.

Overview

Because this order contains detailed findings spanning two hearings and almost six years, a summary will be helpful. The only issue remaining from Laclede's 1999 general rate case is the proper calculation of net salvage, and that is the only issue resolved herein. Unlike the first two Reports and Orders in this case, in this order the Commission finds that the evidence presented dictates a finding in favor of Laclede rather than in favor of Staff.

This order begins with a brief procedural history that explains the two appeals and the currently pending procedural matters. Next is the section detailing the Commission's findings of fact that support its ruling in favor of Laclede, followed by the conclusions of law in which the Commission applies the law to these findings.

Procedural History

Following decisions by the Circuit Court of Cole County and the Missouri Court of Appeals,^[1] this matter now comes before the Commission on remand.

A Report and Order in this case was issued on December 14, 1999. An Order of Clarification was issued on December 21, 1999, and an Order Approving Tariffs was issued December 23, 1999. On December 1, 2000, the Circuit Court of Cole County remanded the case to the Commission for "findings of fact sufficient to support resolution of the net salvage issue."

The Commission issued its Second Report and Order on June 28, 2001. That order was appealed to the Circuit Court of Cole County and then to the Court of Appeals for the Western District of Missouri. On May 28, 2003, the Court of Appeals issued its Mandate to Cole County Circuit Court with directions to the Circuit Court to remand the decision. On May 30, 2003, the Circuit Court entered a docket entry stating that the case was remanded to the Commission "with instructions to provide clearer, more detailed findings of fact that include the rationale for the findings and comply with 386.420 and 536.090, RSMo 2000."

As a result of the remand by the Western District Court of Appeals, the Commission determined that this proceeding should be reopened to take further evidence on the issue of net salvage and depreciation. On September 22-24, 2004, a further hearing was held on the net salvage issue. All the parties were represented at the hearing. Briefs were filed on November 2, 2004.

Pending Motions

On May 14, 2004, after the Commission set this matter for further evidentiary hearing, Laclede filed a motion for reconsideration and an alternative recommendation that a generic case regarding depreciation be established. The parties jointly filed a proposed procedural schedule on June 14, 2004, in which Laclede requested that its pending motion for reconsideration and recommendation for a generic case be held in abeyance until after the completion of this proceeding. On that same date, Staff and Public Counsel filed responses to Laclede's motions suggesting that the motion for reconsideration be denied. Public Counsel also included a request that the Commission determine if the issue of net salvage is now moot given that Laclede has adopted new tariffs since this case was originally decided and would be unable to adjust its rates if the Commission finds in its favor.

On June 21, 2004, Laclede filed a reply to Staff and Public Counsel's responses. Laclede again reiterated that it had intended the Commission to hold its motions in abeyance if the Commission adopted a procedural schedule in this matter. The Commission adopted the parties' proposed procedural schedule on June 24, 2004, but indicated that it would address the pending motions in a separate order.

On July 29, 2004, the Commission directed the parties to file briefs on whether the issue in this case was moot. Those briefs were filed on August 18, 2004.

On August 25, 2004, Laclede and AmerenUE filed a response to the briefs of Staff and Public Counsel. On August 31, 2004, both Staff and Public Counsel filed motions requesting permission to be allowed to file responses to Laclede's brief one day out of time citing to Commission rule 4 CSR 240-2.080. Simultaneously with those motions, the Staff and Public Counsel filed their responses. On September 3, 2004, Laclede and AmerenUE objected to the motion, requested that Staff and Public Counsel's responses be stricken, and replied to those responses.

The Commission's rule 4 CSR 240-2.080(15) provides that "[p]arties shall be allowed not more than ten (10) days from the date of filing in which to respond to any pleading unless otherwise ordered by the commission." Rule 4 CSR 240-2.010(13) specifically excludes briefs from the definition of "pleading." Therefore, the Commission finds that rule 4 CSR 240-2.080(15) does not apply in this situation. Furthermore, neither Laclede nor AmerenUE were harmed by the

additional filing and, in fact, had sufficient time to file yet another reply. The Commission will accept the filings, grant Staff and Public Counsel's motions, and deny Laclede's motion to strike.

On December 9, 2004, Laclede filed a Request Regarding Accounting Adjustment to Implement Depreciation Rates. On December 17, 2004, both Staff and Public Counsel filed motions to strike the pleading from consideration or, in the alternative, responses to the motion. In their motions, Staff and Public Counsel argue that Laclede should not be allowed to supplement its arguments after the close of the briefing schedule and in response to the Commission's deliberations.

The Commission has struggled with the timing of the remaining issues throughout the remanded portion of this case. While it is true that a proper request from Laclede would have included a request for leave to make such a filing, the Commission finds that neither Staff nor Public Counsel have alleged any harm from the pleading. And, in fact, the final arguments from both sides have helped to clarify the issue. Therefore, the Commission will grant Laclede leave to file its pleading and deny the motions to strike it from consideration.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision. The Commission adopts its previous Report and Order and Second Report and Order except as modified by these findings. The Commission notes that it may take notice of facts outside the record in determining mootness.^[2]

The Commission finds that the gas service rates approved in Case No. GR-99-315 became effective on December 27, 1999.^[3] Those rates remained in effect until December 1, 2001, when they were superseded by the gas service rates approved by the Commission in Case No. GR-2001-629.^[4] Those rates remained effective until

November 9, 2002, when they were superseded by the natural gas service rates set in Case No. GR-2002-356,^[5] which rates are currently in effect.

In this Report and Order, the Commission cites primarily to the testimony from the following witnesses:^[6]

Paul Adam, a Staff witness who testified at the first hearing in 1999;

Rosella Schad, a Staff witness who adopted Mr. Adam's testimony and testified at the second hearing in 2004;

William Stout, a Laclede witness who testified at the second hearing in 2004.

Throughout the two hearings held in this case, the parties have had a fundamental disagreement on the proper method for calculating net salvage costs when establishing depreciation rates. It is undisputed that the accrual method used by Laclede to determine the net salvage component of its depreciation rates has traditionally been used by both the Commission and the Company to establish the Company's depreciation rates.^[7]

Because Laclede is the moving party in this case, as a utility requesting a rate increase, it has the ultimate burden of proof. However, as noted above, Staff is the party advocating a change in the depreciation method used not only by Laclede, but almost all utilities in the country. As a result, much of this order discusses support for Staff's challenge to what has been referred to as the standard method of calculating net salvage.

Under the accrual method, the depreciation rate for a particular asset or group of assets is calculated as follows:^[8]

$$\text{Depreciation Rate} = \frac{100\% - \% \text{ Net Salvage}}{\text{Average Service Life (years)}}$$

In this formula, net salvage equals the gross salvage value of the asset minus the cost of removing the asset from service.^[9] The net salvage percentage is determined by dividing the net salvage experienced for a period of time by the original cost of the property retired during that same period of time.^[10] The Commission finds that many natural gas assets will have a negative

net salvage value and corresponding negative net salvage value percentage, since the cost of removing the asset from service frequently exceeds its gross salvage value.^[11]

The accrual method has been used by Laclede and the Commission to determine Laclede's depreciation rates since at least the early 1950s.^[12] It is undisputed that using the accrual method for this purpose is supported by the overwhelming weight of authority on such matters. In both evidentiary hearings, Laclede and AmerenUE provided evidence showing the widespread support among depreciation professionals and authoritative texts for the traditional, or accrual, method of treating net salvage.^[13]

Laclede and AmerenUE also established, and no party disputed, that such a method is consistent with the requirements of the Uniform System of Accounts that this Commission has adopted, and depreciation practices recognized and followed in all but a few regulatory jurisdictions in the United States.^[14] In contrast, Staff was unable to cite any depreciation practitioner, outside of other Staff members, or any depreciation treatise that addressed its proposed treatment of net salvage. In addition, Staff was unable to adequately support or explain its reasoning for adopting this new approach.

During the first evidentiary hearing, Mr. Adam agreed that a proper goal of depreciation is to allocate the full cost of an asset, including its net salvage cost, over the useful life of the asset.^[15] He did not, however, provide any evidence to demonstrate that this goal is not achieved by the accrual method traditionally used by the Commission and employed by Laclede in this case.

The Commission finds that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption.^[16] The Commission further finds that the method utilized by Laclede is consistent with that fundamental goal.

In criticizing the accrual method for determining net salvage, Staff did show that Laclede is recovering more in depreciation for net salvage than it is currently spending.^[17] Ratepayers pay \$2.3 million more in depreciation annually under the accrual method than under Staff's proposed expense method.

Laclede explained this result, however, with evidence showing a consistent and significant upward trend over time in both the installation cost of the plant used by Laclede to provide utility service, as well as in the cost to remove such plant from service.^[18] In fact, just maintaining the net salvage percentage at its historical rate would result in a higher level of net salvage costs than that currently being realized by the Company, since it applies to an asset base that has grown and continues to grow over time. For example, the evidence shows that in 1950 Laclede's total plant in service was only 6 percent of what it is today.^[19]

The Commission has also seen no evidence to suggest that the net salvage costs calculated under the accrual method are not sufficiently reliable. Laclede and AmerenUE pointed to evidence showing that estimates are frequently used in the ratemaking process for deriving returns on equity, allowable pension costs, nuclear decommissioning allowances, and the service lives over which the recovery of capital costs are spread.^[20] Staff, on the other hand, provided no evidence to show that the net salvage estimates derived under the accrual method are any less reliable, known and measurable, or trustworthy than the estimates used in these other ratemaking calculations.^[21]

The estimates are derived through the use of estimating techniques that reflect the continuing impact of factors such as inflation that cause costs to rise. These estimates also reflect the growth in plant that has continued to occur over the last several decades. Two of the depreciation witnesses for Laclede used historical data to demonstrate that recognition of growth factors should continue into the future.^[22] Moreover, both the rate of return witness for the Company and the rate of return witness for Staff presented evidence showing that some level of inflation can be expected to continue in the future.^[23]

The Commission finds no substantive evidence showing that net salvage costs, as determined under the accrual method, have been calculated erroneously. Although Mr. Adam testified in his direct testimony that net salvage costs had been miscalculated, he later acknowledged in a data request response to the Company, as well as during cross-examination, that no such miscalculation had occurred.^[24] Instead, Mr. Adam indicated that the difference between his net salvage calculation and that of the Company's was simply attributable to the fact that they were employing different methods to make that calculation.^[25]

The Commission also notes that the use of estimating techniques is critical to determining the average service lives of a utility's assets under both the methods proposed in this case, to spread and defer the utility's recovery of current capital expenditures over many years into the future.^[26] Ms. Schad acknowledged that average service life estimates may vary, are dynamic, and depend on the judgment of the depreciation analyst, factors which all indicate that estimates of net salvage are no less reliable than the estimates of average service lives.^[27]

The Commission finds that no evidence or satisfactory explanation exists as to why it is inappropriate or unreasonable to use estimates for purposes of determining net salvage costs, but is appropriate to use them for deriving equity returns, allowances for pension costs, decommissioning costs, and the service lives used to allocate the recovery of up-front capital expenditures over many years. Given these considerations, the Commission finds that Laclede's net salvage estimates as derived under the accrual method are reasonable.

The Commission is also not persuaded that the method proposed by Staff will resolve an intergenerational problem. Although Mr. Adam initially testified that his method would address an intergenerational problem, he later conceded on cross-examination that he wished he had not made that claim.^[28] In fact, Mr. Adam acknowledged on cross-examination that to address any intergenerational problem, customers benefiting from the use of an asset should pay for its costs of removal during the service life of the asset, not after it is retired from service.^[29] Since it is clear from the evidence in this case that the accrual method comes closer to matching the costs to

the benefits derived,^[30] the Commission finds that intergenerational equity will be promoted by the continued use of the accrual method.

Laclede's evidence shows that because the accrual method incorporates net salvage costs as a part of the depreciation rate, any difference between actual and estimated net salvage costs will be reflected in adjustments to the depreciation reserve.^[31] The depreciation reserve, in turn, acts as a kind of balancing account that tracks over- and underaccruals of net salvage costs. In this way, the depreciation rates can be subsequently adjusted to ensure that the utility will not over- or undercollect such costs and that the ratepayer will not over- or underpay for such costs.^[32] The Commission's rule requiring the submission of depreciation studies no less frequently than every five years provides a mechanism for monitoring the depreciation reserve so that this balancing can occur. At no point did the Staff dispute the fact that the accrual method operates in this manner.

The evidence also showed that any temporary difference between estimated and actual net salvage costs is reflected in the depreciation reserve that, in turn, is deducted from the utility's rate base pursuant to standard Commission practice.^[33] As a result, ratepayers are compensated at the utility's overall rate of return for the "use" of their money during those times when the utility's outlays for net salvage are less than what has been included in depreciation rates.^[34] In contrast, in the Staff's expense method, any difference between its estimates of net salvage costs and actual net salvage costs are either absorbed by the utility or borne by the customer.^[35]

The Commission also finds that Staff's method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations.^[36] This, in turn, has a negative financial impact on both the utility and its customers by requiring that such obligations be met with more expensive sources of external financings and by driving up the cost generally of obtaining money in the capital markets.^[37] The Commission finds that Staff has not shown that the adoption of its method would justify these increased costs for utility consumers.

Finally, the Commission is concerned about making such a significant change in its policies based on the lack of clear reasoning presented by Staff. The Commission notes that Mr. Adam's proposal was not reviewed by other Staff members prior to being filed, and that the workpapers supporting Staff's proposed method were never included with Mr. Adam's prefiled testimony, but were only offered into the record upon conclusion of Mr. Adam's cross-examination.

[\[38\]](#) It is also clear from the discussion of those workpapers that Mr. Adam adopted his method by simply scratching out the salvage values he had calculated using the accrual methodology and substituting instead lower net salvage

values, based on apparently nothing more than his realization that his original set of values yielded higher dollars in net salvage accruals to the Company than those actually incurred by the

Company in recent periods.[\[39\]](#) Although given the opportunity after the record was reopened, Staff did not present additional evidence sufficient to support its position. These factors lead the Commission to find that Staff has not supported and explained its proposed method with the degree of thoroughness necessary to justify a significant departure from the Commission's traditional policy in this area.

The Commission is also concerned about whether the "safeguards" are sufficient to protect ratepayers from overcollection. Mr. Stout testified that the accrual approach would create a depreciation reserve substantially larger than the annual net salvage costs of recent retirements.

[\[40\]](#) Mr. Stout further testified that these amounts would meet around the year 2020 and that the "safeguards" will correct it.[\[41\]](#) To ensure that ratepayers are protected, the Commission shall adopt a portion of the additional recommendation that Staff proposed.

The Commission finds that Laclede should not be required to segregate the net salvage amounts collected in rates from other corporate funds.[\[42\]](#) The Commission is persuaded that such a requirement is unnecessary given the absence of any evidence showing that utilities have ever failed to pay for such costs when they arose, the existence of other financial protections, including those imposed in connection with Laclede's financing authorizations, and the fact that other costs that have been precollected in rates have

not required such a safeguard.^[43] The Commission also finds that such a requirement would be unwise, because it would tend to increase costs for utility customers by providing less compensation to consumers for the use of their money than does the accrual method.^[44]

Laclede agreed, however, to accept that portion of Staff's proposal that would require the utility to track and account for net salvage amounts received in rates separately from other components of depreciation expense. The Commission finds such an additional requirement would be reasonable to protect the ratepayers.

Summary.

In view of this evidence, the Commission finds that Laclede has shown the accrual method to be just and reasonable and that Staff has failed to show that the Commission should adopt Staff's method of accounting for net salvage. The Commission wants to ensure that the method for tracking these expenditures and collections is clear and that the ratepayers do not overpay for net salvage costs. Therefore, the Commission will require a separate accounting for the net salvage in the depreciation reserve.

Conclusions of Law

The Missouri Public Service Commission has arrived at the following conclusions of law.

Jurisdiction:

Laclede Gas Company is a public utility engaged in the provision of natural gas service to the general public in the state of Missouri and, as such, is subject to the general jurisdiction of the Missouri Public Service Commission under Chapters 386 and 393, RSMo 2000. The Commission also has the authority to prohibit implementation of gas service rates that are unjust or unreasonable rates.^[45]

Burden of Proof:

The burden of proof to show that a proposed tariff is just and reasonable is upon the utility.^[46] Orders of the Commission must be based on substantial and competent evidence, taken on the record as a whole, and must be reasonable and not arbitrary, capricious, or contrary

to law.^[47] Based upon its findings of fact, the Commission concludes that Laclede has met its burden of showing that its method of calculating net salvage depreciation value is just and reasonable. The Commission further finds that its Staff did not clearly articulate any convincing reason to deviate from this method of accounting. The Commission concludes that Laclede Gas Company's depreciation calculation for net salvage value should be made in accordance with Laclede's depreciation method.

Therefore, Laclede shall make the necessary adjustments to its depreciation reserve to account for the accrual method.

Mootness:

A case is moot when a tribunal's decision would not have any practical effect upon any live controversy.^[48] Where an event occurs that makes granting effectual relief impossible, the

case is moot and generally should be dismissed.^[49] This rule applies to contested cases before administrative agencies just as it applies to courts. With respect to utility matters, the general rule is that "issues under old, superseded tariffs are moot and therefore not subject to consideration."

^[50]

The sole issue in this case is whether Staff's or Laclede's method for setting the net salvage value of Laclede's assets for the purpose of ratemaking should be accepted. Originally, the Commission determined that Staff's method of calculation was appropriate. Laclede and AmerenUE appealed this decision.

As noted, new tariffs setting rates became effective on December 1, 2001, and November 9, 2002. Those tariffs provided for rate increases, thus affording prospective relief to Laclede. As Laclede concedes, there is no lawful possibility of any additional moneys to be paid by Laclede's ratepayers under the tariffs in effect from December 27, 1999, to December 1, 2001, just as there would be no lawful way to refund moneys

overpaid by Laclede's ratepayers.^[51] The revenue produced by the effective rates was paid directly to Laclede, unconditionally, pursuant to tariffs approved by the Commission. This revenue became the property of Laclede and no part of it can lawfully be refunded or returned to the ratepayers, nor can additional rates now be collected.

Laclede and AmerenUE argue, and Staff agrees,^[52] that the Commission could order different net salvage depreciation rates for the time period in which those rates were in effect. This would allow Laclede to adjust those depreciation reserves upward and adjust its income downward for that period. Thus, Laclede's depreciation reserve accounts would be increased for future ratemaking periods and some practical relief could be awarded to Laclede.

Accounting Adjustments:

Because this case has been in an appeal status for over five years, to alter the depreciation rates by simply adjusting the depreciation rates would effectively hurt Laclede financially. This is because Laclede would have to show decreased net income for the period as a result of increased depreciation expenses. Laclede requests that the Commission require it to make the immediate change in its depreciation rates but to "also order that Laclede make a corresponding accounting adjustment to decrease the amount that Laclede currently books to net salvage expense."^[53] Laclede makes this suggestion to keep from booking the net salvage expense twice, once to depreciation expense and once to net salvage expense, thus decreasing Laclede's net income.

The Commission has previously found that the net salvage expense is valued at \$2.3 million annually.^[54] The Commission determines that Laclede shall increase its depreciation rates to generate an amount of additional depreciation expense equal to \$2.3 million annually, with a corresponding credit to the depreciation reserve account. The Commission also determines that in order to make this return to the accrual accounting method after the company has been booking rates following Staff's expense method while this case was on appeal, it is just and reasonable to require Laclede to reduce its net salvage expense by an amount equal to the additional depreciation expense generated by the increases in depreciation rates and a corresponding debit to the depreciation reserve account.

The Commission also concludes that in order to ensure the accurate tracking of net salvage accounts, Laclede shall keep a separate accounting of the amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal, as recommended by Staff.

IT IS THEREFORE ORDERED:

1. That Staff of the Missouri Public Service Commission and the Office of the Public Counsel's motion to file replies to Laclede and AmerenUE's briefs are granted.
2. That Laclede Gas Company is granted leave to file its December 9, 2004 pleading and the motions to strike that pleading are denied.
3. That the Report and Order issued on December 14, 1999, and the Second Report and Order issued on June 28, 2001, are readopted by the Commission except as modified by the additional findings of fact and conclusions of law set out in this Third Report and Order.
4. That the calculation of net salvage value for the determination of depreciation rates shall be done in accordance with Laclede Gas Company's recommendations.
5. That Laclede Gas Company shall increase its depreciation rates and booked depreciation expense by \$2.3 million annually, with a corresponding credit to the depreciation reserve accounts, and a decrease to its net salvage expenses by an amount equal to the additional depreciation expense generated by the increases in the depreciation rates, with a corresponding debit to the depreciation reserve.
6. That Laclede Gas Company shall keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal.
7. That this Third Report and Order shall become effective on January 21, 2005.

BY THE COMMISSION

(S E A L)

Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge

Davis, Ch., Murray and Appling, CC., concur;
Gaw, C., dissents;
Clayton, C., dissents, with dissenting opinion to follow;
and certify compliance with Section 536.080, RSMo 2000.

Dated at Jefferson City, Missouri,
on this 11th day of January, 2005.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Laclede Gas Company's Tariff)
To Revise Natural Gas Rate Schedules.)

Case No. GR-99-315

Dissenting Opinion of Commissioner Steve Gaw

I respectfully dissent from the Third Report and Order issued by the majority in the above captioned proceeding. As the majority opinion notes, “a case is moot when a tribunal’s decision would not have any practical effect upon any live controversy.”^[55] The Report and Order continues on to note, “[w]ith respect to utility matters, the general rule is that ‘issues under old, superseded tariffs are moot and therefore not subject to consideration.’”^[56] Despite its explicit recognition that rates resulting from this proceeding have been replaced by those set in two subsequent proceedings^[57], the majority fails to adequately explain how its decision will have any “practical effect upon any live controversy.”

In its Report and Order, the majority briefly discuss the concept of mootness.^[58] Despite the repeated claims of mootness, the Commission properly recognized that its finding could have a practical, albeit negative, effect on Laclede and thereby could avoid the strict dictates of such a finding. Specifically, the Commission noted that:

the Commission could order different net salvage depreciation rates for the time period in which those rates were in effect. This would allow Laclede to adjust those depreciation reserves upward and adjust its income downward for that period. Thus, Laclede’s depreciation reserve accounts would be increased for future ratemaking periods and some practical relief could be awarded to Laclede.^[59]

When asked directly whether Laclede truly sought such “practical relief”, counsel appeared to waiver. In light of the punitive effect that this adjustment would have on Laclede’s past earnings as well as the corresponding reduction to rate base to be used in future proceedings, I specifically asked Laclede counsel whether it would prefer to have the Commission make a mootness finding or to have the Commission issue the suggested practical relief.^[60] Given the “rock and a hard place” implication of this question, Laclede’s counsel adeptly avoided the question.^[61]

In spite of the possible practical relief acknowledged by the majority in its Report and Order, the majority instead opted for accounting manipulations designed solely to attempt to avoid the mootness doctrine while simultaneously alleviating any negative financial implications on Laclede. Specifically, the majority orders a \$2.3 million increase in depreciation rates designed to reflect the utilization of the accrual method for treating negative net salvage. In addition, the majority ordered a corresponding \$2.3 million debit to depreciation reserve. The accounting manipulations have no practical effect in that the adjustments do not change revenues, expenses, net income, plant-in-service, depreciation reserve or rate base. In addition, the adjustments do not, and of course, should not result in any change to retail rates.^[62] Given the lack of “practical relief” granted by the majority, I find that this matter should be deemed moot.

Aside from the bar provided by the mootness doctrine, I harbor reservations regarding the appropriateness of the accrual method of recovering for net salvage. Specifically, I am concerned about the use of estimates to recover costs that are uncertain and that may never actually be incurred. In its testimony, Laclede and AmerenUE note that the Commission routinely uses estimates. In fact, the companies note that the use of estimates is implicit in the calculation of depreciation rates. The difference, however, is that the depreciation rate determination uses estimates to provide for the return of costs that: (1) have already been incurred and (2) are of a certain magnitude. Any lack of accuracy in the estimates used for the calculation of depreciation rates (i.e., average service life) is not further compounded by a concern regarding the magnitude of the cost to be recovered or whether the cost will ever actually be incurred.

In addition to the use of estimates for determining depreciation expense, the companies also direct the Commission’s attention to the use of estimates in calculating pensions and nuclear decommissioning. In reality, cost of removal is an advance by ratepayers for an expense which is of an uncertain future magnitude. It is therefore, more like these examples than costs incurred and recovered through depreciation. Nevertheless, while these examples are a better analogy than depreciation, the companies’ comparison is again not entirely accurate. Although the actual incurrence of the expense is certain, the ultimate magnitude of the expense is not. In each of these situations, a legally enforceable obligation has been created by statute which mandates the eventual payment of these costs. Thus, while the Commission may have concerns regarding the

use of estimates for determining the magnitude of such costs, it is assured that such expenditures will ultimately be incurred.

In reality, along the spectrum of expense certainty, the recovery for cost of removal is most like the recovery of OPEBs (retirement benefits other than pensions); it is an advance by ratepayers for an uncertain future expenditure of a questionable magnitude.



OPEBs Nuclear Decommissioning and Pension Depreciation
(Incurrence and magnitude uncertain) (uncertain) - certain magnitude - uncertain (certain) (Incurrence and magnitude certain)

In the early 1990s, the Commission was confronted with numerous requests to adopt accrual accounting for post-retirement benefits other than pensions. Similar to the situation at hand, the utilities repeatedly noted that: (1) accrual treatment was consistent with GAAP as well as recent Financial Accounting Standards Board pronouncements; (2) the vast majority of other Commissions had adopted accrual treatment; (3) utilization of cash accounting would result in reduced cash flow and (4) disparate treatment by the Missouri Commission would hamper these utilities in accessing the capital markets.

Despite these arguments the Commission repeatedly refused to adopt accrual accounting for OPEBs. Instead, in response to arguments about the uncertainty of the incurrence of such costs, the Commission continued to use the cash method for recovering these expenses. [\[63\]](#)

Given the Commission's persistent refusal to grant recovery of OPEB expenses that are of uncertain magnitude and that may not actually be incurred, the utilities eventually sought redress in the General Assembly. While the legislature mandated the use of accrual accounting for

OPEBs, it also sought to prevent a situation where the utility realized a windfall as a result of never actually incurring the expense. Therefore, similar to the funding requirements for pensions and nuclear decommissioning, the legislature required all monies collected to be placed in an external fund and used only for retiree benefits.^[64] In fact, the legislature noted that “in no event shall any funds remaining in such funding mechanism revert to the utility.”^[65]

It is not my intention to predetermine, through this dissent, any decision on my part regarding the appropriate methodology for calculating and recovering net salvage costs. I understand that the accrual method benefits the cash flow of the Company. Here, the Company proposes that ratepayers be required to advance money for removal of assets. The Commission must balance the benefits and risks to the consumer of making the consumer pay such advances. If the accrual method does not adequately provide that balance, other avenues should be utilized that will. This may include using the expense method or following the legislature’s lead in requiring that the net salvage be segregated and held in trust. Ratepayer money should be advanced to the Company for possible future expenditures only after the Commission has weighed the accuracy of the estimate of the expenditures, the likelihood of the incurrence of the expenditure and the financial stability and reliability of the Company.

Respectfully submitted,

Steve Gaw
Commissioner

Dated at Jefferson City, Missouri,
on this 18th day of January, 2005.

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In Re the Matter of Laclede Gas Company’s Tariff)

To Revise Natural Gas Rate Schedules

) **Case No. GR-99-315****Opinion of Commissioner Robert M. Clayton III**

-

This Commissioner respectfully concurs in part and dissents in part from the majority opinion in this matter. Although this Commissioner generally agrees that the accrual method as proposed by Laclede and AmerenUE should have been utilized in the underlying rate case in deciding the issue of mass account net salvage recovery, there is no real relief that can be afforded the utility and the matter is, therefore, moot. Because this decision will have no practical effect upon any live controversy, any Report and Order by this Commission would constitute little more than a declaratory ruling or general statement of policy, which, despite this Commissioner's wishes, is not authorized by Missouri law. In addition, some clarification of the issues discussed in the Report and Order is appropriate, especially in regard to burden of proof and the need for further study and review of the issue.

This remand relates to the issue of depreciation and how best to account for a component known as net salvage value of mass account plant, or the estimated cost of removal of mass account plant less any amount recovered in selling the removed materials. ^[66] There are two competing proposals for how best to account for this issue. Staff has recommended using a "Cash" or "Expense" method of accounting for this component of depreciation. Laclede has suggested the use of an accrual method of accounting and has made reference to this method as the "Traditional" or "Standard" method. This Commissioner finds the use of such language argumentative and conclusory and a more thorough analysis of the issue's history is required.

Depreciation is the loss in value incurred by consumption or prospective retirement of plant in the course of service from such known causes as wear and tear, obsolescence and decay. ^[67] "Depreciation accrual rates are used to match all revenues earned during a given time period with all the expenses incurred during that same time period to produce those revenues. In each year of service customers are charged with the portion of the asset that it or they consume or use." ^[68]

"Net salvage value" means the salvage value of property retired less the cost of removal. ^[69] If the salvage value of the retired property is greater than the cost of removing and disposing of the property, then the net salvage value is a positive number. That value is recognized in rates and

reduces the depreciation recovery during the plant's life. If the salvage value of the property is less than the cost of removing and disposing of the property, then the net salvage value is a negative number, and that net cost is referred to as "negative net salvage." [70] The question presented in this matter is whether an anticipated negative net salvage value should be included in the depreciation rates so that such cost is recovered in rates over the service life, or whether it should be recovered only if and when it actually occurs. [71]

In the early days of utility regulatory accounting, net salvage was not considered a significant issue because, 1) the plant in service was a fraction of the value of plant in service today, 2) there was little thought of removing plant because the industry was brand new, and 3) the plant in service actually had a positive net salvage value rather than a negative net salvage value. At least until the 1950s, depreciation rates were simply a flat percentage applied to plant in service; in the 1960s, depreciation rates by account were established for Laclede. [72] As late as the mid-1990s, state regulatory commissions addressed the issue of net salvage in a variety of ways, including both the accrual and expense methods described above and some combining parts of both. [73] As Ms. Schad discusses, in 1960, Laclede's depreciation accrual rate was increased due to increased net salvage costs. [74] Subsequent to the late 1970's, Laclede's rate cases, including the depreciation rates, settled pursuant to Stipulation and Agreement. There is no way to know whether or to what extent Laclede's depreciation rates reflected positive or negative net salvage value. [75] Since various methods of depreciation calculation have been used over the years, the terms "Traditional" or "Standard" should not be used.

As the projected costs associated with negative net salvage continued to grow, a fairness issue arose. As discussed above, the reason for setting depreciation rates is to recover the cost of the use of plant over the time it is in service. If a large portion of those costs comes from retiring plant, then customers that use it should contribute to the cost of removing it. Each party addresses the question of "intergenerational equity" arguing that their own proposed depreciation treatment more closely assigns the costs of plant to those customers who benefit from it. [76]

The Staff became concerned that current customers were paying more in rates than should be reasonably attributed to them. Unsatisfied that using past retirements as a guide to future

needs or simply estimating future costs or averaging the two could yield a reliable result, in the early 1990s, the Staff began advocating its current position that net salvage value should be expensed, rather than accrued.^[77] Staff felt that if the company were not incurring retirement costs commensurate with the amounts it was recovering in rates, it would receive a windfall of extra revenue.^[78] Further, at some point the company would likely incur the costs of removing plant but the funds could have been spent already and no longer available as the collections would have occurred years before.^[79] On the other hand, AmerenUE and Laclede assert that the accrual method, while not perfect, addresses the issue better, because current customers are paying for the full costs of plant that might cost more to take out of service than it cost to put into service.^[80]

The record indicates that the accrual method has been used in Missouri since the early 1960's, and continues to be used by the vast majority of state regulatory commissions today. The exceptions to the rule include the sovereign states of New Jersey and Pennsylvania, which are required by applicable state law to use the expense method, and Georgia.^[81] Some commissions, such as Delaware and Arkansas, experimented with the expense method and later returned to the accrual method. Other states have approved the use of the expense method when the parties stipulate to it in a larger comprehensive settlement, a category in which Missouri falls. Suffice it to say, however, that the accrual method is far more widely used, and had been used almost exclusively in Missouri in contested cases until the present dispute.^[82]

As noted above, Staff's position is that the accrual method cannot accurately estimate the costs, conditions or timing of removal. Plant may remain in service longer than originally anticipated or may not be removed at all. As technology and environmental concerns change, the estimated cost of removal may change. Staff asserts that estimating the future cost of a future event that may or may not take place is vague at best, and cannot reach the standard of "known and measurable."^[83]

In cases before the Commission in which a rate increase is sought, the company seeking the rate increase bears the burden of proof.^[84] Commission policy or procedure must be

promulgated in a rule,^[85] and *stare decisis* does not apply to Commission decisions,^[86] no matter how often or consistently a Commission decision is made.

Each rate case stands on its own and is decided by its respective Commission. Laclede established that the accrual method has a significant history in this state and is relied upon frequently, if not exclusively, by the vast majority of state Commissions. The utility showed that the accrual method is a reasonable method, relied on in Missouri in past cases, which yields reasonably reliable information on which to establish “just and reasonable” rates. This method purports to have safeguards to protect the interests of ratepayers and maintain a minimum level of accuracy. This Commissioner believes that Laclede made a *prima facie* showing that this method is one method that would lead to “just and reasonable” rates.

This Commissioner believes that it is up to the Staff to rebut or refute that *prima facie* showing. It is up to the Staff to show that the accrual method is no longer suitable or, at the very least, is vastly inferior to the expense method or any other method, with specific evidence and proof. Although the Staff did establish that the accrual method does have certain inherent imperfections, it never satisfactorily established that the expense method was so superior to the accrual method that a change in accounting practices and departure from the Uniform System of Accounts was warranted. It was the inability to articulate a sufficient reason for the departure from an established norm that caused this case to be remanded on two different occasions by the Court.^[87]

Staff argued in its brief that, “There is no evidence in this record that the formula accurately predicts actual cost of removal.” Staff further argues that there is no empirical study to prove the accuracy of the accrual method.^[88] In turn, Staff does not offer any studies or specific evidence that the method is not an accurate method of determining the proper amount to be included in the depreciation schedule. Rather than demand the company to show a study that the method is accurate, Staff should produce a study proving the inaccuracy of the method or provide evidence of specific failures that have occurred in Missouri or elsewhere because of the method’s use.

Notwithstanding the conclusion reached in this Opinion, this Commissioner is mindful of the concerns that have been raised about the accrual method. The accrual method may not completely address questions of intergenerational equity, a point the utilities make throughout the case. There are valid concerns about mass account plant not being retired as anticipated or plant

costing less to remove than was accrued in the depreciation reserve. In addition, the accrual method will always accrue a greater amount in the depreciation reserve than what is spent to retire plant, and ratepayers will never be made completely whole. Because of the pooling of assets for depreciation purposes, the customer can only be made whole when there is no more growth in the system and all assets are fully depreciated. These concerns should be evaluated and considered in future cases.

This Commissioner concurs with the majority in this case that the appropriate method of accounting for mass account net salvage is the accrual method. This method is used around the country and conforms to the Uniform System of Accounts. A departure from it could profoundly affect the utility; such a change should not be made lightly. The increased cash flow generated by the accrual method is of a great benefit to the utility. It enables it to invest in new plant and keep existing plant in good repair. While the Commission strives to keep rates low for energy consumers, it has an obligation to the industry it regulates to see that operations are sufficiently funded to provide safe and adequate service and to allow an opportunity for a reasonable return on investment. This method also properly assigns a share of cost to ratepayers who benefit from the plant.

This Commissioner believes further study and discussion are necessary among the Office of the Public Counsel, the Staff, the regulated utilities in this state and their customers. The parties in the matter have raised valid concerns about the shortcomings of both methods and further work may result in changes that ameliorate those shortcomings. As the net salvage value component continues to grow, the issue will only continue to increase in importance. A generic docket or rulemaking discussion would provide an additional forum for discussion in arriving at a method that will satisfy the concerns of the parties and the Commission.

This Commissioner believes that it is imperative to follow Staff's recommendation that a separate accounting be made by the utility of the accrued depreciation for net salvage. Staff asserts that, "[I]f allowances recorded in the depreciation reserve attributable to cost of removal accruals are separately identified, regulatory analysis and more accurate rates will be easier."^[89] There was extensive testimony about the various "safeguards" in place to protect current and future ratepayers under the accrual method, but those need to be reviewed and adjusted regularly so that intergenerational equity and accuracy of recovery is maintained.^[90] Staff continued in its

argument that, “[a]bsent such information, it would be difficult at best to effectuate any customer safeguards against overcharges for cost of removal.”^[91] Lastly, this Commissioner also believes that the analysis must include a regularly scheduled comparison and historical tracking of the accrued amounts for removal costs versus the actual amounts spent on removing plant. Since the customer is advancing the funds for future estimated expenses, it is critical to monitor the actual plant retirement costs to verify that annual accruals do not deviate on an increasing basis over time from the actual retirement expenditures.

However, contrary to the different accounting treatment and tracking mechanism suggested above, the suggestion that these funds be separated from general funds of the company would be counter-productive and that proposal is not well taken.

The Commission majority believes that resolving this question will make an impact and decision is necessary in the case. Despite my agreement about the use of the accrual method, believe the entire matter is moot. No rate can or will be changed as a result of the Report and Order. The outcome of no future rate proceeding or tariff filing will be predetermined as a result of the Report and Order nor will the decision have binding effect.

I agree with the majority that “[a] case is moot when a tribunal’s decision would not have an practical effect upon any live controversy.”^[92] Further, I agree that “[w]ith respect to utility matters: the general rule is that ‘issues under old, superseded tariffs are moot and therefore not subject to consideration.’”^[93] However, there are limited exceptions to the mootness doctrine, and “a court has discretion to review a moot case where the case presents a recurring unsettled legal issue of public interest and importance that will escape review unless the court exercises its discretionary jurisdiction.”^[94] I believe this exception applies only to judicial review and does not apply to this Commission, as the Commission has no authority to issue a policy statement that can bind itself or future Commissions, and therefore cannot “settle” an unsettled area of the law.

In conclusion, this Commissioner argues that this matter is moot and should be dismissed as such. It is for this reason that this Commissioner cannot support the majority’s Report and Order.

Respectfully submitted,

Robert M. Clayton III
Commissioner

Dated at Jefferson City, Missouri,
on this 14th day of January, 2005.

[1] State of Missouri ex rel. Laclede Gas Company And Union Electric Company d/b/a AmerenUE v. Public Service Commission, 103 S.W.3d 813 (Mo. App., W.D. 2003).

[2] State ex rel. Monsanto Co. v. Public Service Commission, 716 S.W.2d 791, 793 (Mo. banc 1986); State ex rel. Donnell v. Searcy, 347 Mo. 1052, 152 S.W.2d 8, 10 (Mo. banc 1941).

[3] Order Approving Tariff Sheets Filed in Compliance with Commission's Order, Case No. GR-99-315 (issued December 23, 1999).

[4] Order Approving Unanimous Stipulation and Agreement, etc., Case No. GR-2001-629, *supra*.

[5] Order Approving Tariffs in Compliance with Commission Order, Case No. GR-2002-356 (issued November 8, 2002).

[6] The Commission also admitted into evidence and has considered testimony (or depositions in lieu of testimony) from several other witnesses, *e.g.*, Mark Oligschlaeger, a Staff witness; Steven Fetter, R. Lawrence Sherwin, Warner Baxter, and Barry Cooper, witnesses for Laclede and Ameren.

[7] Exh. No. 23, p. 4.

[8] Exh. 23, p. 4.

[9] *Id.*

[10] Exh. 23, pp. 4-5.

[11] Exh. 23, p. 9; Schedule 1.

[12] Tr. 1733.

[13] Exh. 23, p.3; Exh. 25, pp. 4-6; Exh. 26, pp. 4-5; Exh. 136, p. 9.

[14] Exh. 26, pp. 2, 4-5, 13; Exh. 143, p. 7; Exh. 135, pp. 7-9; Exh. 143, pp. 6-7.

[15] Tr. 895-896.

[16] Exh. 23, p. 3; Exh. 25, p.7; Exh. 26, p. 4.

[17] Exh. No. 92, p. 7.

[18] Exh. 23, pp. 21-26; Exh. 25, p. 9; Tr. 841.

[19] Ex. 136, Schedule WMS-3-1.

[20] Tr. 1845-47; Exh. 136, p. 25; Exh. 137, p. 10.

[21] Tr. 2039-40; Exh. 157, p.103; Exh. 156, p. 60.

[22] Tr. 841; Exh. 23, pp. 18-23; Exh. 25, p. 9, Schedule 1.

[23] See, Tr. 841; Exh. No. 2, pp. 4, 7, 10-11, 19-21, D-6, Schedule 8; Exh. No. 59, pp. 9-17, Schedules 4 and 7.

[24] Tr. 884-885.

[25] Id.

[26] Tr. 841; Exh. 23, pp. 8-10.

[27] Tr. pp. 1549–1550.

[28] Tr. 896.

[29] Id.

[30] Exh. No. 25, pp. 6-8.

[31] Exh. 138, p. 19.

[32] Exh. 138, pp. 19-20.

[33] Exh. 138, p. 21.

[34] Id.

[35] Exh. 138, p. 21.

[36] Exh. 134, pp. 8-10.

[37] Exh. 134, p. 9.

[38] Tr. 929.

[39] Tr. 889-892; Exh. No. 124.

[40] Tr. 1425-26.

[41] Id.

[42] Exh. 142, pp. 12-13.

[43] Exh. 150; p. 3 of Staff's Memorandum, Condition 6; Exh. 147, p. 114; Exh. 157, pp. 92-93; Tr. 1854-55, 1872-75.

[44] Exh. 157, pp. 71-72.

[45] Section 393.130, RSMo 2000.

[46] Section 393.150.2, RSMo 2000.

[47] Section 536.140, RSMo 2000.

- [48] State ex rel. Reed v. Reardon, 41 S.W.3d 470, 473 (Mo. banc 2001).
- [49] Id.; and see Armstrong v. Elmore, 990 S.W.2d 62, 64 (Mo. App., W.D. 1999).
- [50] St. ex rel. Missouri Public Service Co. v. Fraas, 627 S.W.2d 882, 885 (Mo. App., W.D. 1981).
- [51] State ex re. Utility Consumers' Council of Missouri v. Public Service Commission, 585 S.W.2d 41.
- [52] Staff's Brief on Mootness, filed August 18, 2004, p. 2.
- [53] Request Regarding Accounting Adjustment to Implement Depreciation Rates, (filed December 9, 2004), para. 3.
- [54] Ex. 23, page 7; Tr. 1279-80.
- [55] Report and Order at page 18, citing to State ex rel. Reed v. Reardon, 41 S.W.3d 470, 473 (Mo. banc 2001).
- [56] Id. citing to State ex rel. Missouri Public Service Co. v. Fraas, 627 S.W.2d 882, 885 (Mo.App. 1981).
- [57] Id. at pp. 6-7.
- [58] Id. at pp. 18-19.
- [59] Id. at 19.
- [60] Tr. at 1316.
- [61] Tr. at 1319.
- [62] The Company is undoubtedly aware that it is prohibited, under the bar against retroactive ratemaking, from seeking rate increases to reflect accrual treatment of net salvage for the period in which the rates arising out of this case were in effect.
- [63] See, In re St. Joseph Light & Power Company, 2 Mo.P.S.C.3d 248 (1993); In re United Telephone Company of Missouri, 2 Mo.P.S.C.3d 403 (1993); In re Missouri-American Water Company, 2 Mo.P.S.C.3d 446 (1993); In re Southwestern Bell Telephone Company, 2 Mo.P.S.C.3d 479 (1993).
- [64] See, Section 393.292 regarding the recovery and funding of nuclear decommissioning costs; Section 386.315 regarding the recovery and funding of OPEB costs; and federal ERISA laws regarding the recovery and funding of pension expense. Noticeably, the legislature also deemed it appropriate for the creation of a special fund for the safe keeping of amounts collected through depreciation expense. Section 393.240.2 specifically requires each utility to "set aside the moneys so provided for out of earnings and carry the same in a depreciation fund and expend such fund only for such purposes and under such rules and regulations, both as to original expenditure and subsequent

replacement, as the commission may prescribe. (emphasis added). The rationale behind the utilities' and Commission's evolution away from such "depreciation funds" is unclear.

[65] Section 386.315.2 RSMo.

[66] *State of Missouri ex. rel. Laclede Gas Company and Union Electric Company d/b/a AmerenUE v. Public Service Commission of the State of Missouri*, Missouri Court of Appeals, Western District, Case No. WD61486, March 4, 2003. This matter dealt with the net salvage value of mass accounts. Life span accounts were not at issue.

[67] See *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, August 1996, p.318.

[68] See generally, *Depreciation Systems*, Frank K. Wolf and W. Chester Fitch, 1994, pp.4-6.

[69] 18 CFR Part 101 (36) Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Federal Power Act.

[70] Wolf and Fitch, *supra* note 3, at 7- 8.

[71] As noted above, this matter does not pertain to "Life Span" accounts, but only with "mass accounts." A life span account relates to the final retirement of a major structure. Mass accounts are accounts "consisting of large numbers of similar units, the life of any one of which is not, in general dependent upon the life of any of the other units. For such classes of plant, the retirement of a group of units occurs gradually until the last unit is retired. The retirements and additions to the account occur more or less continually and systematically." NARUC, *supra* note 2, at 321-322.

[72] Supplemental Rebuttal Testimony of Staff Witness Rosella L. Schad, p. 4.

[73] Schad, *id.* at 7.

[74] Schad, *id.* at 17.

[75] Schad, *id.* at 5.

[76] Schad, *id.* at 11-15; Supplemental Direct Testimony of Laclede Witness William E. Stout, at pp. 12-17. This principle of "intergenerational equity" is also called a "matching principle." According to Wolf and Fitch, *supra* note 3, at 7-8, "[t]he matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses. *** The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue."

[77] Schad, *supra* at Schedule 8-4.

[78] See the Direct, Rebuttal and Surrebuttal Testimony of Staff Witness Paul W. Adam, adopted by Staff Witness Rosella L. Schad, in which Mr. Adam discusses the inaccurate projections to remove the "Gas Holders" from service by 2006.

[79] Schad, *supra* at 15-18, Schedule 8-8 – 8-11.

[80] Supplemental Direct Testimony of Ameren UE Witness Martin J. Lyons, p.8.

[81] Tr. at 2009.

[82] Schad, *supra* at Schedule 8.

[83] Schad, *supra* at 12 and 13.

[84]
§393.150, RSMo. 2000.

[85]
See §536.010(4), RSMo. 2000.

[86]
State ex. rel. GTE North, Inc. v. Mo. Pub. Serv. Comm'n, 835 SW2d 356,371 (MoApp 1992); *Cent. Hardware Co., Inc. v. Dir. Of Revenue*, 887 SW2d 593,596 (Mo. banc 1994); *State ex. rel. AG Processing, Inc. v. Mo. Pub. Serv. Comm'n*, 120 SW3d 356,371 (Mo. banc 2003) 356,371 (MoApp 1992).

[87]
The Court stated: The Commission's findings of fact also imply that the Staff's depreciation method of calculating net salvage is less likely to result in Laclede overrecovering from its customers than Laclede's depreciation method. The Commission's findings of fact fail, however, to support such a contention. No evidence or facts of any nature are cited by the Commission to support this conclusion. *** Similarly, the Commission's findings of fact stating that the Staff's depreciation method is less likely to result in overrecovery from Laclede's customers are conclusory for failing to provide any support of this finding." Note 1, *supra*

at 5.

[88]
Staff Brief at p.4.

[89]
Staff Brief at p. 10.

[90]
Lyons, *supra* at 10-19.

[91]
Staff Brief at p. 10.

[92]
Third Report and Order, Missouri Public Service Commission, Case No. GR-99-315, Issued January 11, 2005, at 17.

[93]
Id. at 18.

[94]
State ex. Rel. Jackson County v. Missouri Public Service Commission, 985 SW2d 400 (MoApp WD 1999).

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	
	:	07-0585
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	
	:	07-0586
Proposed general increase in electric delivery service rates.	:	
	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	
	:	07-0587
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	
	:	07-0588
Proposed general increase in gas delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	
	:	07-0589
Proposed general increase in gas delivery service rates.	:	
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Illinois Power Company d/b/a AmerenIP	:	
	:	
	:	07-0590
Proposed general increase in gas delivery service rates.	:	
	:	(Cons.)

ORDER

DATED: September 24, 2008

TABLE OF CONTENTS

I.	PROCEDURAL BACKGROUND	1
II.	NATURE OF AIU'S OPERATIONS	6
III.	AIU'S PROPOSED TEST YEAR AND REVENUES	6
IV.	RATE BASE	7
A.	Introduction	7
B.	Resolved Issues	7
C.	Contested Issues	9
1.	Plant Additions since Last Rate Case	9
a.	AIU's Position	9
b.	Staff's Position	24
c.	CUB's Position	41
d.	Commission Conclusion	42
2.	Plant Additions Disallowed in the Last Rate Case	46
3.	Property Held for Future Use	49
4.	Security System Installations	51
5.	Cash Working Capital	52
a.	AIU's Position	52
b.	Staff's Position	58
c.	The AG's and CUB's Position	60
d.	Commission Conclusion	61
6.	Physical Losses and Performance Variations	63
a.	Staff's Position	63
b.	AIU's Position	69
c.	Commission Conclusion	73

7.	Working Capital Allowance for Gas in Storage	74
8.	Hillsboro Base Gas Inventory Valuation (Prior Adjustment)	78
9.	Hillsboro Base Gas Inventory Valuation (New Adjustment)	82
a.	AIU's Position	82
b.	Staff's Position	89
c.	Commission Conclusion	94
D.	Approved Rate Bases	94
V.	OPERATING REVENUES AND EXPENSES	95
A.	Introduction	95
B.	Resolved Issues	95
C.	Contested Issues	98
1.	AMS Charges	98
2.	Incentive Compensation Costs	102
3.	Rate Case Expense	108
4.	Uncollectibles Expense	116
5.	Injuries and Damages Expense - AmerenIP	119
6.	Energy Toolkit	120
7.	Collateral and Prepayments	122
8.	Reliability Initiatives	127
9.	Public Utility Fund Base Maintenance Contribution	131
10.	Depreciation Life for Electric Distribution Equipment	134
11.	Net Salvage Method for Depreciation Expense	136
12.	NESC Violation Correction Costs After the Test Year	139
13.	Gas Account 880 – AmerenIP	142
14.	Gas Accounts 830 and 834 - AmerenCILCO	145

15.	Gas Account 823 - AmerenIP - Hillsboro	148
16.	Gas Accounts 920-923 - AmerenIP.....	154
D.	Approved Operating Income/Revenue Requirement	155
VI.	COST OF CAPITAL/RATE OF RETURN	156
A.	Introduction	156
B.	Capital Structure	156
1.	Common Equity Balances	156
2.	Preferred Stock Balances	157
3.	TFTN Balance-AmerenIP	157
4.	Short-Term Debt Balances.....	157
5.	Long-Term Debt Balances	165
C.	Cost of Debt.....	165
1.	Short-Term Debt	165
2.	Variable Rate Long-Term Debt	166
3.	Embedded Cost of Long-Term Debt for AmerenCILCO	166
4.	Cost of AmerenIP's Transitional Funding Trust Notes	166
5.	AmerenIP's Embedded Cost of Long-Term Debt	169
6.	AmerenCIPS' Embedded Cost of Long-Term Debt.....	173
D.	Cost of Preferred Stock.....	178
E.	Cost of Common Equity	179
1.	Overview	179
2.	Annual Versus Quarterly DCF Model	182
3.	Growth Rates	185
4.	CAPM Analysis	192
5.	Beta.....	193

6.	Expected Risk Premium	195
7.	Risk Premium Model	201
8.	Adjustment for Reduced Risk of Gas Operations	203
9.	Commission Conclusion	211
a.	CAPM	211
b.	DCF	213
c.	Risk Premium Model	215
d.	Adjustment for Reduced Risk of Gas Operations	215
e.	Authorized Returns on Equity	216
10.	Commission Authorized Rates of Return on Rate Base	217
VII.	PROPOSED RIDERS	219
A.	Rider VBA	219
1.	AIU's Position	219
2.	Staff's Position	223
3.	AG's Position	225
4.	CUB's Position	232
5.	IIEC's Position	234
6.	AARP's Position	235
7.	Commission Conclusion	236
B.	Rider QIP	238
1.	AIU's Position	238
2.	Staff's Position	242
3.	AG's Position	245
4.	CUB's Position	252
5.	IIEC's Position	255

6.	AARP's Position	257
7.	LGI's Position	259
8.	Kroger's Position	260
9.	Commercial Group's Position	260
10.	Commission Conclusion.....	261
VIII.	COST ALLOCATION METHOD	265
A.	COSS-Based Rates vs. Across-the-Board Rate Changes.....	265
1.	AIU's Position	265
2.	Staff's Position	270
3.	AG's Position.....	272
4.	IIEC's Position.....	273
5.	Commercial Group's Position	278
6.	Commission Conclusion.....	279
B.	COSS in Next Rate Cases.....	281
IX.	RATE DESIGN/TARIFFS TERMS AND CONDITIONS.....	282
A.	Resolved Gas and Electric Issues	282
B.	Resolved Gas Issues	283
C.	Resolved Electric Issues.....	289
D.	Contested Gas Issues.....	292
1.	Gas Bank Sizing and Daily Balancing Tolerances	292
a.	AIU's Position	292
b.	Staff's Position.....	299
c.	IIEC's Position	305
d.	CNE-Gas' Position.....	306
e.	Commission Conclusion	312

2.	AmerenIP Rate 76 as a Stand-Alone Tariff	314
3.	Elimination of AmerenIP's Rider OT	315
4.	Elimination of AmerenCIPS' Stand-by Reserve	318
5.	Intra-Day Nominations	320
6.	Daily Telemetry	323
7.	Small Volume Transportation Tariff.....	328
8.	12-Month Notification for Seasonal Customers	329
9.	Minimal Winter Use Delivery Service Provisions.....	332
10.	Uniform Terms Among Tariffs	335
11.	Weather Normalization.....	336
12.	Imbalance Trading	338
13.	Purchase/Confiscation of Customer-Owned Gas.....	339
14.	Critical Day and Operational Flow Order Notice Provisions	343
15.	AmerenCIPS and AmerenCIPS Metro-East Rate Areas	346
E.	Contested Electric Issues	347
1.	Rate Limiter.....	347
2.	Street Lighting	354
3.	Allocation of Costs to Subclasses	359
4.	Combining DS-3 and DS-4.....	359
X.	FINDINGS AND ORDERING PARAGRAPHS.....	363

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	
	:	07-0585
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	07-0586
Proposed general increase in electric delivery service rates.	:	
	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	07-0587
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	07-0588
Proposed general increase in gas delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	07-0589
Proposed general increase in gas delivery service rates.	:	
	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	07-0590
Proposed general increase in gas delivery service rates.	:	(Cons.)

ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On November 2, 2007, Central Illinois Light Company d/b/a AmerenCILCO ("AmerenCILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS

("AmerenCIPS"), and Illinois Power Company d/b/a AmerenIP ("AmerenIP") each filed with the Illinois Commerce Commission ("Commission") new and/or revised tariff sheets for electric and gas service. AmerenCILCO, AmerenCIPS, and AmerenIP are each a wholly owned subsidiary of Ameren Corporation ("Ameren") providing residential, commercial, and industrial electric and gas service throughout their respective service areas. AmerenCILCO, AmerenCIPS, and AmerenIP are collectively hereinafter referred to as Ameren Illinois Utilities ("AIU"). The new and revised tariff sheets ("Proposed Tariffs") proposed changes in electric and gas rates and the establishment of new riders, to be effective December 17, 2007. On December 5, 2007, the Commission entered six Suspension Orders suspending the Proposed Tariffs for each company to and including March 30, 2008 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. The Suspension Orders identify the specific tariff sheets filed by AIU. Upon suspension, AmerenCILCO's electric and gas filings became identified as Docket Nos. 07-0585 and 07-0588, respectively; AmerenCIPS' electric and gas filings became identified as Docket Nos. 07-0586 and 07-0589, respectively; and AmerenIP's electric and gas filings became identified as Docket Nos. 07-0587 and 07-0590, respectively. On March 12, 2008, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including September 30, 2008.

Notice of the filing of the proposed rate increases was posted in each of AIU's business offices and was published twice in newspapers of general circulation within each of AIU's service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, —~~Notice~~ Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services." In addition, AIU sent notice of the filing to its customers in a bill insert.

On December 4, 2007, AIU was notified of certain deficiencies in its filings in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). The deficiency letters required AIU to submit various missing information and provide explanations of certain portions of the rate filings. AIU provided information in response to the deficiency letters on January 4, 2008.

Petitions seeking leave to intervene were filed by the People of the State of Illinois through the Attorney General ("-AG"), the Cities of Bloomington, Champaign, Decatur, Monticello, and Urbana and the Town of Normal (collectively referred to herein as the Local Government Interveners ("-LGI")), Citizens Utility Board ("-CUB"), AARP,¹ System Council U-05 of the International Brotherhood of Electrical Workers, an association consisting of Local Unions 51, 309, 649, 702, and 1306 ("IBEW"), Grain and Feed Association of Illinois ("GFA"), Kroger Company ("Kroger"), Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"), Constellation Energy Commodities Group, Inc., Vanguard Energy Services, LLC, and the Coalition of Energy Suppliers, which consists of Constellation NewEnergy, Inc., Direct Energy Services, LLC, Integrity

¹ In 1999, the "American Association of Retired Persons" changed its name to simply "AARP," in recognition of the fact that people do not have to be retired to be members.

Energy Services Corporation, and MidAmerican Energy Company. The University of Illinois, Air Products and Chemicals Company, ArcelorMittal Steel Company, Cargill, Inc., Caterpillar, Inc., Enbridge Energy, LLC, GBC Metals, LLC, Illinois Cement Company, PPG Industries, Inc., Tate and Lyle Ingredients Americas, Inc., and Viscofan USA, Inc. also intervened as members of the Illinois Industrial Energy Consumers ("IIEC"). The Commercial Group, an ad hoc association of retail companies that own and operate retail stores in the service areas of AIU intervened as well. For purposes of this proceeding, the Commercial Group consists of Best Buy Company, Inc., JC Penny Corporation, Inc., Macy's, Inc., and Wal-Mart Stores, Inc. All of the petitions to intervene were granted. Commission Staff ("Staff") participated as well.

On February 6, February 11, February 13, February 19, February 26, and February 28, 2008, a public forum was held in Marion, Decatur, Belleville, Peoria, Quincy, and Champaign, respectively, for the purpose of receiving public comment on the general increase in electric and gas rates proposed by AIU. These locations were selected because they represent some of the larger population centers in the AIU service areas. A transcript of each public forum was made and is available on the Commission's e-Docket system.

Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on January 3 and June 3, 2008. Thereafter, evidentiary hearings were held on June 9 through June 13, 2008. Following the Commission's ruling on a petition for interlocutory review, an additional evidentiary hearing was held on July 1, 2008. Appearances were entered by counsel on behalf of AIU, Staff, the AG, LGI, CUB, AARP, GFA, IIEC, Kroger, the Commercial Group, and CNE-Gas. The record was marked "~~Hard~~ and Taken" on August 11, 2008. Following the submission of AIU's response to a Post-Record Data Request by the Administrative Law Judges pursuant to Section 200.875 of 83 Ill. Adm. Code 200, "Rules of Practice," the record was reopened for the purpose of admitting said response and the Staff reply into the record. The record was again marked "Hard and Taken" on September 3, 2008.

At the evidentiary hearings, AIU called 33 witnesses to testify. The 33 witnesses include (1) Michael Adams, a Vice President with Concentric Energy Advisors, Inc. ("Concentric"),² (2) Mary Batchter, Tax National Director for Statistics and Sampling at Ernst & Young LLP, (3) Krista Bauer, Manager of Compensation and Performance for Ameren Services Company ("AMS"),³ (4) Scott Cisel, Chief Executive Operating Officer of each AIU company, (5) Stephen Colyer, Director of Gas Operations for each AIU company, (6) Wilbon Cooper, a Manager of Rate Engineering and Analysis within AMS' Regulatory Policy and Planning Department, (7) Michael Getz, Managing Supervisor of

² Concentric is a management consulting and economic advisory firm specializing in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

³ AMS is the service company subsidiary of Ameren and provides various services to its affiliates, including AIU.

Business Performance for AMS, (8) Scott Glaeser, Vice President of Gas Supply and System Control for the Gas Supply Division of AmerenEnergy Fuels and Services Company, (9) Philip Hanser, a principal in The Brattle Group, an economic consulting firm, (10) Laurie Karman, Managing Supervisor of Credit and Collections for AMS, (11) Leonard Jones, Managing Supervisor of Restructured Services within AMS' Regulatory Policy and Planning Department, (12) Charles Laderoute, President of the consulting firm Charles D. Laderoute, Ltd., (13) Mark Livasy, Superintendent of Energy Delivery Illinois for each AIU company, (14) Martin Lyons, Vice President and Controller of AMS and each AIU company, (15) Keith Martin, Manager of Customer Service and Energy Efficiency for each AIU company, (16) Kathleen McShane, President of the economic consulting firm Foster Associates, Inc., (17) Robert Mill, Director of AMS' Regulatory Policy and Planning Department, (18) Timothy Moloney, Managing Supervisor in AMS' Credit Risk Management Department, (19) Joseph Mullenschlager, Manager of Corporate Security for AMS, (20) Craig Nelson, Vice President of Regulatory Affairs and Financial Services of each AIU company, (21) Michael O'Bryan, Senior Capital Markets Specialist in Treasury-Corporate Finance of AMS, (22) Ronald Pate, Vice President of Regional Operations for each AIU company, (23) Robert Porter, Manager of Acquisitions for AMS, (24) Ronald Stafford, Managing Supervisor of Regulatory Accounting in AMS' Controller's Function, (25) Bruce Steinke, Vice President and Controller of Ameren, AMS, and each AIU company, (26) David Strawhun, a Career Engineer in Distribution System Planning for AMS, (27) John Taylor, a consultant with Concentric, (28) Stephen Underwood, Manager of Gas Storage for AMS, (29) William Warwick, Managing Supervisor of Rate Engineering within AMS' Regulatory Policy and Planning Department, (30) Gary Weiss, Manager of Regulatory Accounting for AMS, (31) Andrew Wichmann, a Financial Specialist in AMS' Controller's Function, (32) John Wiedmayer, a Project Manager of Depreciation Studies for Gannett Fleming, Inc.,⁴ and (33) Robert Willen, Supervising Engineer of the Load Analysis Group within AMS' Corporate Planning Function.

Twelve witnesses testified on behalf of Staff. The Staff witnesses include (1) Theresa Ebrey, (2) Mary Everson, and (3) Daniel Kahle, Accountants in the Accounting Department of the Financial Analysis Division of the Commission's Bureau of Public Utilities, (4) Janis Freetly and (5) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, (6) Cheri Harden and (7) Peter Lazare, Rate Analysts in the Rates Department of the Financial Analysis Division, (8) Harry Stoller, Director of the Energy Division of the Bureau of Public Utilities, (9) Greg Rockrohr, a Senior Electrical Engineer in the Engineering Department of the Energy Division, (10) Eric Lounsberry, Supervisor of the Gas Section in the Engineering Department, (11) Dennis Anderson, a Senior Energy Engineer in the Gas Section, and (12) David Sackett, an Economic Analyst in the Policy Department of the Energy Division.

⁴ Gannett Fleming, Inc. is a consulting firm that, among other things, assists clients prepare accounting and financial data for revenue requirement and cash working capital issues, allocate the cost of service among customer classes, and design customer rates.

IIEC offered five witnesses at the evidentiary hearings. IIEC's witnesses include Alan Chalfant, Michael Gorman, James Selecky, Robert Stephens, and David Stowe from the consulting firm of Brubaker & Associates, Inc.⁵ David Effron, a consultant specializing in utility regulation, and Michael Brosch, a principal in the consulting firm Utilitech, Inc., testified on behalf of the AG and CUB. The AG also called Scott Rubin, an independent consultant and attorney specializing in matters affecting the public utility industry, to testify. Christopher Thomas, CUB's Director of Policy, Lynne Kiesling, a Senior Lecturer in the Department of Economics at Northwestern University, and Martin Cohen, an independent consultant specializing in regulatory policy analysis, testified on behalf of CUB. Kroger called Kevin Higgins, a principal at Energy Strategies, LLC,⁶ to testify. Jeffrey Adkisson, GFA Executive Vice President and Treasurer, testified for GFA. Nancy Hughes, a principal and Senior Director with R.W. Beck, Inc.,⁷ offered testimony for LGI. The Commercial Group called Richard Baudino, a consultant with the firm of J. Kennedy & Associates, Inc., to testify. James Germain, the Director of Customer Supply Management for CNE-Gas, and Lisa Rozumalski, a Manager of Gas Operations for CNE-Gas, both testified on behalf of CNE-Gas. Ralph Smith, a consultant with the accounting and regulatory consulting firm of Larkin & Associates, PLLC, testified for AARP. Paul Noble, Business Manager of IBEW Local 72 and Chairman of IBEW System Council U-05, testified on behalf of IBEW.

AIU, Staff, the AG, LGI, CUB, AARP, GFA, Kroger, CNE-Gas, the Commercial Group, and IIEC each filed an Initial Brief and Reply Brief. A Proposed Order was served on the parties. All but AARP filed a Brief on Exceptions. AIU, Staff, the AG, CUB, GFA, CNE-Gas, and IIEC each filed a Brief in Reply to Exceptions. The Briefs on Exceptions and Briefs in Reply to Exceptions have been considered in the preparation of this Order.

As a general matter, the Commission notes that in their respective Briefs on Exceptions, several parties complain that the Proposed Order did not specifically lay out each and every aspect of their argument and that in some instances the conclusion did not dispose of every aspect of, or basis underlying, each proposal. First, the Commission notes that, excluding the appendices, the proposed order is 360 pages in length and while not perfect, is generally adequate in summarizing parties' positions and arguments. Additionally, the Commission observes that Illinois courts have held that "The Commission is not required to make a finding on each evidentiary fact or claim; rather, it is sufficient that its findings are specific enough to permit an intelligent review of its decision." (City of Chicago v. Illinois Commerce Commission and Commonwealth Edison Company, 264 Ill. App. 3d 403, 409, 636 N.E.2d 709 (First District Appellate Court, 1993)) The Illinois Supreme Court further stated that "If the findings support the order, then the reviewing court examines the evidence to ascertain if the findings are supported by the facts." (Brinker Trucking Co. v. Illinois Commerce Commission, 19 Ill.

⁵ Brubaker & Associates, Inc. offers consulting services in the energy, economic, and regulatory fields.

⁶ Energy Strategies, LLC is a consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

⁷ R.W. Beck, Inc. offers consulting services in the areas of finance, energy, water/wastewater, and solid waste enterprises.

2d 354, 357, 166 N.E.2d 18, 20 (1960)) The Commission believes that in this lengthy and complicated Order it is not necessary to restate every aspect or basis for every argument either in the statement of a party's position or in the conclusion.

II. NATURE OF AIU'S OPERATIONS

Ameren formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIU covers roughly the lower two-thirds of Illinois. AmerenCILCO currently serves approximately 209,313 electric customers and 212,287 gas customers. Within AmerenCIPS' footprint are two rate areas: AmerenCIPS and AmerenCIPS Metro-East. AmerenCIPS currently serves approximately 387,097 electric customers and 185,484 gas customers. The AmerenCIPS Metro-East area is the former Illinois service area of Union Electric Company d/b/a AmerenUE ("AmerenUE"). This territory was transferred to AmerenCIPS in 2005. AmerenCIPS Metro-East serves approximately 18,000 customers in the Alton area. AmerenIP currently serves approximately 614,847 electric customers and 418,700 gas customers. All of AIU's operations are within Illinois, although an affiliate of AIU (AmerenUE) provides utility service in Missouri. Other affiliates of AIU provide unregulated services.

III. AIU'S PROPOSED TEST YEAR AND REVENUES

AIU proposes to use the 12 months ending December 31, 2006 as the test year in this proceeding. No party objects to the use of this test year. The Commission concludes that the historical test year AIU proposes is appropriate for purposes of this proceeding.

The Proposed Tariffs reflect an increase in delivery service revenues for all but the gas customers of AmerenCILCO. For AmerenCILCO gas customers, AIU proposes a decrease in revenues. The proposed changes in the delivery service operating revenues for each service type and territory are as follows:⁸

	ELECTRIC		GAS	
	Revenue Change	% Change	Revenue Change	% Change
AmerenCILCO	\$10,151,000	8.22	-\$3,851,310	-4.67
AmerenCIPS	\$30,847,000	14.49	\$14,396,496	22.11
AmerenIP	\$139,320,000	39.12	\$55,912,346	41.84

AIU determined these revenues using an 11.00% cost of equity. Since the proposed increase for AmerenIP electric customers is comparatively higher, for the first year that

⁸ The numbers contained in the table reflect only proposed delivery service revenues since it is only those revenues at issue in this proceeding.

new rates are in effect, AIU proposes to limit the increase to an 8.5% increase in *bundled* rates for the residential customer class as a whole, based on current power supply costs.

AIU's last electric delivery service rate cases were consolidated Docket Nos. 06-0070, 06-0071, and 06-0072. AmerenCILCO's last gas rate case was Docket No. 02-0837. AmerenCIPS' last gas rate case was Docket No. 03-0008. AmerenIP's last gas rate case was Docket No. 04-0476.

IV. RATE BASE

A. Introduction

The rate base represents the net level of investment that a utility company has dedicated to public service on which it is entitled to earn a return. The rate base consists principally of book investment in utility plant and working capital, less deductions to reflect other sources of funds, such as deferred taxes. Schedules showing AIU's rate base for each utility at present and recommended rates for the test year ending December 31, 2006 were presented by AIU and Staff.

B. Resolved Issues

1. Accrued OPEB Adjustment

AG/CUB witness Effron recommends an adjustment to reflect Accrued Other Post Employment Benefits ("OPEB"). AIU agrees with this proposed adjustment. The Commission finds the AG/CUB proposed adjustment reasonable and appropriate and it is hereby adopted.

2. Written Procedures for Gas Losses

Staff recommends that AIU develop written procedures for the treatment of the source and types of losses from underground storage fields. AIU agrees to work with Staff to draft clear procedures regarding the accounting treatment of gas losses. The Commission finds Staff's recommendation to develop written procedures regarding the treatment of gas losses reasonable and directs AIU to collaborate with Staff to develop such written procedures that are agreeable to both AIU and Staff.

3. Electric Material and Supplies Inventory

Staff witness Everson proposes an adjustment to electric materials and supplies inventory for the percentage of accounts payable because accounts payable represents vendor-financing. AIU agrees with this adjustment. The Commission finds Staff's proposed adjustment to electric material and supplies inventory to be reasonable and it is hereby adopted.

4. Additional Cash Working Capital

Staff witness Kahle proposes an adjustment to eliminate AIU's proposed increase to rate base for additional cash working capital ("GWC") for the electric operations related to a permanent increase in accounts receivable balances. AIU agrees to remove this proposed increase for each of the electric utilities. However, AIU, states that it reserves the right to raise this issue again in the future. The Commission finds the proposal to eliminate any increased accounts receivable balances related to electric operations reasonable and such increases should not be reflected in rate base in this proceeding.

5. Storm Recovery Costs

AIU initially proposed a pro forma adjustment to capture storm recovery costs that each of AIU's electric utilities incurred during 2006 and 2007. AIU's proposed pro forma adjustment utilized a five year amortization for these combined 2006 and 2007 storm recovery costs, and included each utility's unamortized storm recovery amounts in that utility's respective rate base. Staff witness Rockrohr recommends that the Commission reject AIU's proposed pro forma adjustment explaining that AIU's proposed rate treatment of storm recovery costs could provide a disincentive for the utility to bolster its distribution system to withstand storms. AIU agrees to modify its proposed treatment of storm recovery costs and use a six-year historical normalization period to calculate the storm recovery costs individually allowable for each of the AIU electric utilities. Mr. Rockrohr finds this alternative rate treatment of storm recovery costs described by AIU witness Stafford to be acceptable. The Commission finds AIU's amended proposal for the treatment of storm recovery costs reasonable and it is hereby adopted.

6. ADIT and Other Reserves

AG/CUB witness Efron recommends that Accumulated Deferred Income Taxes ("ADIT") be adjusted to follow the treatment of the related reserves or accruals in the determination of rate base related to Pensions and Deferred Compensation. AIU agrees with these proposed adjustments. The Commission finds the AG/CUB's adjustment to ADIT related to Pension and Deferred Compensation reasonable and it is hereby adopted.

In its Brief on Exception, the AG recommends that the Proposed Order be modified to deduct the injuries and damages reserve from rate base, arguing that these are ratepayer-supplied funds. AIU disagrees with this proposal, noting that its modification of injuries and damages expense treatment in this case from an accrual basis to a cash basis for ratemaking, based on a five-year average of cash claims paid, is similar to the recommendation of Staff in these proceedings and to how such costs were established in Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.). AIU further states that the use of a cash basis eliminates the existence of a reserve balance for ratemaking, because there is no debit to expense and credit to a reserve account, or an

advance payment to be recorded as an asset or as a negative reserve balance. In other words, a reserve balance, positive or negative, simply does not exist. It appears to the Commission that while a reserve balance still exists on the utilities' balance sheets, as the AG argues, it is only for reporting, not ratemaking, purposes. The Commission finds that the AG's proposed adjustment is not necessary for these reasons and rejects it.

7. Allocation for Common Plant for Substations

AIU allocates common facilities by primary function, in accordance with "The Illinois White Paper," adopted by the Commission in Docket No. 98-0894. While Staff witness Everson initially expressed concern with AIU's proposed allocation, she now agrees with AIU's allocation and does not propose any adjustment. The Commission finds the allocation previously decided by the Commission is appropriate and that approach is hereby adopted for purposes of allocating common plant for substations in this case.

C. Contested Issues

1. Plant Additions since Last Rate Case

a. AIU's Position

AIU states that, although it is in compliance with Commission document retention rules, certain aspects of its recordkeeping practices need to be improved to facilitate a timely and thorough review of plant additions. Moreover, AIU claims to have previously acknowledged that some of the documentation supporting plant additions was not provided to Staff as timely as it could have been. Having said this, AIU asserts that the requirement that parties engage in full and fair discovery and produce evidence in support of their position is not a one-way street.

AIU claims that despite repeated requests, Staff has never disclosed specifically which invoices were disallowed and for what reason. AIU argues that Staff's methodology for disallowing plant additions – that is, sampling a portion of additions and calculating a disallowance percentage that is applied to all additions – makes the failure to provide this information especially problematic. According to AIU, this is not a case where it has failed to document over \$100 million of plant additions, as Staff's adjustment suggests. Disallowing a percentage of additions and applying that percentage to total plant additions, AIU avers, magnifies the impact of each disallowed invoice. Given that the ultimate dollar impact of each disallowed invoice is greater than any actual invoice amount, AIU claims identification of the specific invoices at issue is critical. AIU contends that Staff's failure to provide this information has prejudiced AIU. AIU argues that Staff's sampling methodology results in an overstatement of the proposed adjustment by about \$111 million.

Identification of the invoices at issue, AIU claims, was accomplished through a process of elimination in which AIU "guessed" at the reason why Staff believes certain additions are allegedly unsupported. AIU says it provided documentation and explanation for every invoice that it believes Staff witness Everson disallowed. AIU states that Ameren Ex. 19.12 provides detailed information relating to approximately 1,300 invoices. Schedules 1 through 6 of the exhibit, AIU adds, list each invoice disallowed and explains why the disallowance is not appropriate. In some instances where AIU says it either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson, her adjustment was accepted. In surrebuttal, AIU compiled Ameren Ex. 43.6, which revised Ameren Ex. 19.12 and provided additional invoices and more supporting documentation and explanation. Ameren Exs. 19.13 and 61.1, AIU claims, provide similar supporting data for electronic transactions. According to AIU, all of these exhibits demonstrate that the amount of plant additions AIU seeks is adequately supported. AIU asserts that Staff dismisses all of the additional support and explanation provided in rebuttal and surrebuttal.

AIU asserts that Ms. Everson employs an invoice-by-invoice approach that is at odds with Staff's approach to analyzing plant additions in other rate cases. In other cases, AIU claims Staff often looks to continuing property records and other non-invoice documentation in order to identify additions that vary significantly in comparison to a utility's prior plant addition expenditures. AIU states that in contrast to Staff's typical review, in this case, Ms. Everson demanded that the AIU provide invoice level support for all selected expenditures. In AIU's view, this approach was burdensome, unwarranted, and unnecessary.

AIU says that among other things, Staff requested a list of all projects whose total costs were above \$500,000, a total of 64 projects. AIU indicates that Staff requested invoices associated with 37 of these projects, of which Staff included 35 in its sample. AIU says it collected, by various queries on AIU's general ledger systems, details of the projects within Ms. Everson's request. This information was then used to compile a list of invoices, where each invoice was associated with a unique voucher number. AIU says these voucher numbers were then used to locate the hard copies of each invoice, which were then scanned and provided to Ms. Everson for review.

AIU says Ms. Everson conducted a review of invoices to determine what percentage of these invoices, for each of the utilities, was not supported by proper documentation. Ms. Everson states that she test sampled supporting documentation for third party vendors for capital additions. She cited seven issues or deficiencies with the cost substantiation provided by AIU: (1) duplicate invoices; (2) billings to the wrong company; (3) invoices not found that correspond to the listing of invoices provided; (4) amounts on invoices that did not correspond to the listing; (5) projects not determinable from the invoice or the invoice is not related to the project; (6) illegible invoices; and (7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. AIU states that Ms. Everson used her total of unsupported documentation to calculate the percentage of total project costs that is not supported. AIU says she then applied the percentage of additions for which AIU did not provide

supporting documentation to the total of plant additions to calculate her adjustment to plant additions, reducing rate base by this amount. AIU complains that at no point has Ms. Everson identified specific invoices for which she recommends disallowance or the reason for the disallowance. In its Initial Brief, AIU also describes the efforts it made to obtain information it believed it needed to evaluate Ms. Everson's proposed disallowance.

According to AIU, the most important problem undermining Ms. Everson's analysis is her failure to identify which invoices she disallowed and why. In AIU's view, this limits the ability of AIU or the Commission to confirm or refute Ms. Everson's analysis. AIU states that although its' Data Requests 5.06, 5.07, and 5.08 requested specific information identifying each invoice disallowed and the reasons for each disallowance, Staff failed to provide this information. By failing to provide the specific reason for each denied invoice, AIU says it was forced to guess at the denial reason in its attempts to explain or refute her findings.

AIU says it recognizes that it bears the initial burden of proving the reasonableness and prudence of expenditures. AIU believes it has satisfied its burden of proving its plant additions, and argues that Staff has failed to meet its burden of proving its adjustment. AIU states that the burden of proof encompasses two concepts - the burden of persuasion and the burden of production. (AIU Initial Brief at 25, citing Consolidated Communications Consultant Services, Inc. v. Illinois Bell Telephone Company, Docket No. 99-0429) According to AIU, although the burden of persuasion – the ultimate burden of persuading the tribunal that the necessary elements of a claim have been proven – is assigned at the beginning of a dispute and does not shift during the course of the proceeding, the burden of producing evidence shifts between the parties as the case proceeds, depending on the nature of specific evidence and the issue it addresses. AIU asserts that in rate cases, once a utility makes a showing of the costs necessary to provide service under its proposed rates, it has established a prima facie case, and the burden then shifts to others to show that the costs incurred by the utility are unreasonable because of inefficiency or bad faith. (AIU Initial Brief at 25, citing City of Chicago v. Illinois Commerce Commission, 478 N.E.2d 1369, 1375, (Ill. Ct. App. 1985) (City of Chicago)) AIU claims that where Staff proposes an adjustment, Staff bears the burden of producing evidence to support the reasonableness of the adjustment. AIU contends that burden is not met by pointing the finger back to the utility and arguing that the utility has not met its burden of proof. (AIU Initial Brief at 25, citing Commonwealth Edison Company ("ComEd"), Docket Nos. 83-0537/84-0555, Order at 183-84)

According to AIU, the Commission and courts recognize that the proponent of a position has the burden of supporting its position with credible, admissible evidence. AIU believes it produced evidence supporting its plant additions. Staff did not think the evidence was good enough. AIU says Staff is free to take that position, but it is ultimately the Commission, not Staff, that determines whether a party has met its burden of proof. AIU asserts that throughout this proceeding it put forth voluminous evidence supporting plant additions.

AIU argues that Staff failed to do anything sufficient to meet its burden with respect to its proposed adjustment. AIU says Staff never conducted an investigation of AIU's records at their offices. AIU suggests that had an on-site review occurred, any questions Ms. Everson had about AIU's documentation could have been answered. AIU complains that Ms. Everson never sent additional data requests seeking information in addition to or different from the information AIU provided in response to Staff Data Requests MHE 3.01-3.06. AIU complains that apart from correcting a few errors, Ms. Everson's adjustment did not change from her direct testimony, despite the massive amount of information produced by AIU in response to her concerns.

AIU says Ms. Everson did not rebut Dr. Batcher's comments regarding Ms. Everson's lack of documentation in her rebuttal testimony. According to AIU, Dr. Batcher testified that Ms. Everson did not provide any explanation of why she did not maintain detailed records of the review of sampled costs. AIU believes this is important because the sampled costs should be available to all parties to review and either agree or contest by arguments to the regulations, sound practice, or providing additional supporting or refuting evidence. In AIU's view, it is unfair to affected parties to deny them the ability to confirm or refute determinations made about individual sampled costs. AIU says that although it may be able to guess the reasons some of the invoices were rejected and provide counter arguments or additional supporting documents, that is a poor substitute for knowing why each invoice was rejected.

AIU witness Taylor states that sampling is the application of probability theory and statistics to gain knowledge about a population of concern, by the selection and review of individual observations within this population. Audit sampling, AIU avers, is the application of sampling techniques to the goals of an audit. AIU states that an —~~audit~~” is defined as an analysis used to ascertain the validity or reliability of information. According to Statement of Auditing Standards (~~SAS~~) No. 39 (AU 350.01): —~~Audit~~ sampling is the application of an audit procedure to less than 100 percent of the items within an account balance or class of transactions for the purpose of evaluating some characteristics of the balance or class.” (AIU Initial Brief at 28, citing SAS No. 39, Auditing Sampling)

According to Dr. Batcher, given the importance of having a representative sample, planning regarding an audit sample is key. The first steps, AIU avers, are to learn about the population to be sampled, the type of estimates to be made from the sample, and the precision needed. Whether a statistical or judgment sample is used, AIU says the auditor approaches the testing of account balances with the recognition that some inconsistency in the sample details is to be expected, even though the account balances are fundamentally correct because of factors such as minor clerical errors, discounts, and irretrievable documentation. According to AIU, a materiality threshold is established as part of the sample planning process in recognition of these minor inconsistencies. For example, AIU suggests a materiality threshold of 1% might be established for invoices that can not be located on current systems. If testing is of older systems that are no longer used or, invoices have been archived, AIU suggests

the threshold might be increased to something larger, like 5%, which in the auditor's judgment, makes allowance for the retrieval difficulties which do not, in and of themselves, indicate a problem with the invoice. AIU says other planning steps include consideration of the sample selection methodology, establishment of criteria for the review of selected invoices, determination of the format for documenting the individual decisions made for the selected invoices and the specific failure reason applied to each failed invoice, and the estimation, reporting, and documentation to be kept.

Dr. Batcher states that given the importance of having a representative sample, regulators often impose documentation standards. Dr. Batcher cites as examples, the Office of the Inspector General from the Department of Health and Human Services, and various state taxing authorities, as well as the Internal Revenue Service ("IRS"), which she says requires individual tracking of the results of the review of each sampled items, the estimators used, and various additional specific details.

It is Dr. Batcher's opinion that Staff has failed to provide the details of the careful planning typical of an audit sample acceptable for regulatory decisions. AIU says the sampling procedures were described as being based on judgment, knowledge of Commission rules, and experience, but the specific planning steps and documentation of the rationale for sample design decision were not provided. AIU complains that there is no rationale given for the choice of a judgmental rather than a statistical sample, no description of steps taken to assess the representative nature of the judgmental sample, no description of decision rules used in the evaluation of sampled costs, or of any of the other aspects of sample planning.

AIU argues that by only reviewing invoices associated with specific projects above \$500,000 in total costs, Staff effectively divides the population into two populations, and selects a sample from only one of these populations. In AIU's view, this is no longer sampling the population of total plant additions, but sampling a population with total costs above \$500,000. AIU says the remainder of costs associated with total plant additions (those costs outside of this population) was not sampled and is a distinct population.

Staff errs, AIU argues, by applying the characteristics of the sample it reviewed to a population that Staff did not review. AIU says there are two main types of plant additions: (1) Specific Projects – those projects whose total costs are above \$100,000 and are related to a specific work order; and (2) Blanket Projects – reoccurring purchases or those projects whose total costs are below \$100,000. Staff, AIU avers, did not review any invoices for specific projects whose total are less than \$500,000, nor did Staff review any blanket projects. AIU argues that there is no reason to believe that the percentage of invoices associated with specific projects that Staff reviewed is representative of the percentage of invoices in all plant additions. AIU says, for instance, blanket projects include reoccurring purchases and installation costs of certain equipment, such as transformers. This population of costs, AIU suggests, may not include invoices, but rather receipts or other forms of recording an exchange, whereas specific projects are more often partially comprised of invoices.

Staff's rebuttal testimony, AIU claims, does not provide any evidence that the alleged substantiation error rate found in projects larger than \$500,000 would be the same as the error rate in the smaller projects. According to AIU, Staff provides the unsupported statement that larger projects would be expected to have better documentation than smaller projects so, by inference, the alleged error rate would be a conservative estimate for the smaller projects. In fact, AIU says there are situations with carefully designed, unbiased statistical samples, in which Dr. Batchner has seen instances where larger projects or expenditures had higher error rates.

Staff's inclusion of electronic transactions as a portion of unsupported invoices, AIU asserts, is also improper. AIU says Staff's review is limited to invoices and does not include a review of supporting documentation related to electronic transactions. AIU believes it is unreasonable to determine a category of costs is fully unsupported simply because Staff fails to review support for that category of costs. AIU argues that this is synonymous to an auditor failing to review current inventory and concluding that such an inventory does not and has never existed.

According to AIU, Ms. Everson's statement that AIU offered no other sample is incorrect. AIU says that Mr. Taylor's rebuttal testimony and that of Dr. Batchner provides explanations of the proper population for which the sample's characteristics should be applied. AIU adds that Ameren Ex. 19.12 is a review of Staff's adjustment with the inclusion of all general ledger line items that Staff challenged. Within these exhibits, AIU claims it applied the review of these challenges to the proper population, calculated the amount still unsupported after review, and applied this percentage to the population from which the sample is derived. AIU asserts that this analysis is based on Staff's chosen sample, but provides a more complete and rigorous analysis of the sample and applies the sample's characteristics to the proper population.

AIU states that Mr. Taylor quantified the effect of Staff's improper application of its sample to total plant additions. AIU says Staff samples \$35,446,676 out of \$64,367,442, the population of projects with total costs over \$500,000. AIU adds that the population that Staff does not sample from, those projects with total costs under \$500,000 and blanket projects, totaled \$547,845,558. AIU argues that incorrectly applying the sample's characteristics to the total plant additions results in a proposed disallowance of \$124,622,861. AIU further argues that correctly applying the sample's characteristics to the population from which the sample is derived results in a proposed disallowance of \$13,614,957. According to AIU, Staff's incorrect evaluation of the sample results in an overstatement of the proposed disallowance totaling \$111,007,904.

AIU states that although Ms. Everson employs other audit methods that she could have used to validate and support capital additions as a whole, she errs by relying exclusively on her sample without also taking into consideration the results of her other audit reviews. AIU contends that Ms. Everson could have used continuing property records and property unit retirement records to review the AIU's plant additions;

however, a review of those records is not discussed anywhere in Ms. Everson's testimony.

Ms. Everson's analysis, AIU claims, is at odds with work done by other Staff witnesses in this case. AIU says Mr. Rockrohr samples the ten largest projects for each utility, and found issues with only two of those projects. One project related to plant held for future use, the other to a security system at an AmerenCIPS facility. AIU says the reasons for recommended disallowance of these projects relates to whether the investments were prudently incurred, not whether the project costs were sufficiently documented. According to AIU, Mr. Rockrohr's recommendation of only two disallowances is in contrast to Ms. Everson's conclusions in her direct testimony. AIU asserts that since Ms. Everson's approach applies to the entire universe of additions, she in effect is disallowing a second time some of the same capital additions dollars Mr. Rockrohr has proposed to disallow.

Ms. Everson's failure to take acquisitions, timing, and changes in accounting systems into account, AIU avers, leads to misleading and unfair results. AIU states that for AmerenCILCO's electric operations, 100% of the transactions reviewed occurred prior to 2005, prior to the acquisition of CILCO by Ameren. AIU adds that these projects were not transferred from Construction Work in Progress ("GWIP") to Utility Plant In Service until after 2004, and therefore are included in Ms. Everson's sample. AIU complains that Ms. Everson's sample results, however, were applied to 100% of all 2005 and 2006 capital additions placed in Utility Plant in Service. Since Ms. Everson has not considered how timing of transactions impacts her weighted disallowance calculations, AIU asserts that the application is flawed. AIU claims a more correct approach would attempt to differentiate the timing of transactions that give rise to 2005 to 2006 capital additions in a case such as this, where different accounting and invoice storage systems were employed with different owners, and the resulting application was applied to capital additions that for the most part, would have occurred after the transition periods. AIU says it is possible that pre-2005 transactions may be representative of post 2005 transactions, but Ms. Everson has not made that determination.

According to AIU, disallowing electronic transactions skews the percentage calculation of unsupported additions. AIU says all electronic transactions at issue occurred prior to October 2004 (acquisition of IP by Ameren) and yet the results were included in Ms. Everson's unsupported percentage for all additions. AIU says Ms. Everson's disallowance included 100% of all electronic transactions included within her sampled electric and gas projects. For gas projects, AIU indicates that those transactions totaled \$2,286,148.32. AIU says Ms. Everson's unsupported percentage, with electronic transactions, is 51.74%. When this percent is applied to \$118,215,000.00 of 2003-2006 capital additions, the resulting disallowance is \$61,167,000.00 of capital additions. According to AIU, if Ms. Everson had adopted the same approach used by Staff in the prior IP electric rate case and excluded electronic transactions from her sample, the unsupported percentage would have changed to 9.62% from 51.74%, and resulted in a disallowance of \$11,372,000.00. AIU asserts

that Ms. Everson's inclusion of \$2.286 million of electronic transactions in the denominator of her unsupported calculation resulted in a proposed disallowance of \$50 million in capital additions. AIU also asserts that the application of Ms. Everson's unsupported percentage to any Commission authorized 2004 AmerenIP gas capital additions approved in Docket No. 04-0476 is a form of retroactive ratemaking, because the Commission has already approved inclusion of such additions in rates.

AIU believes Ms. Everson's exclusion of electronic transactions supporting AmerenIP expenditures is unfounded for other reasons as well. AIU states that Ameren Ex. 19.13 provides the detailed electronic transaction disallowed by Staff in its calculation of the disallowance for AmerenIP electric and gas plant additions since the last rate case. AIU contends that IP's electronic records are reliable and accurate representations of its costs. AIU says it explained in detail the process for creating and approving the invoices and how the invoices tie into the accounts payable system and that in the prior rate case, Staff did not propose to disallow any electronic transaction data.

AIU says that Ameren Ex. 61.1 contains its response and supplemental response to Staff Data Request 14.03, in which Staff requested the vendor invoices to support the amounts shown on Ameren Ex. 19.13 for plant additions. AIU asserts that Ameren Ex. 61.1 explains that, with respect to IP, vendor payment support for Ameren Ex. 19.13 is available in electronic format due to the electronic Contractor Invoicing system used by IP. AIU says that although information summarizing the electronic invoice records is already provided in Ameren Ex. 19.13, additional electronic information associated with vendor payments is available if desired. Thus, in response to Ms. Everson's concern in rebuttal that no actual invoices have been provided to support IP's plant additions, AIU claims Ameren Ex. 61.1 contains paper printouts of contractor invoice records that were electronically created and stored in IP's Contractor Invoicing system. AIU states that each electronic invoice contained in Ameren Ex. 61.1 shows all of the information necessary to substantiate project costs for specific plant additions for IP, such as contractor name, descriptions of the work, work order numbers, and the person approving the invoice for payment.

The methodology employed by Ms. Everson in this case, AIU asserts, is not consistent with Staff's approach in prior cases. AIU claims that while it is not suggesting that Staff is required to audit plant additions the same way in every case, the fact that the audit was performed differently in this case than in other cases demonstrates that other audit techniques were available to supplement Staff's review of plant additions in this case.

In Docket No. 07-0566 for ComEd, AIU asserts that Staff witness Griffin raised a number of issues with regard to ComEd capitalization policies and capital additions, and discussed changes to the ComEd Property Unit Catalog. AIU says Mr. Griffin did not propose a calculation of an unsupported percentage similar to that presented by Ms. Everson. According to AIU, there is no evidence of a similar review undertaken or discussed by Mr. Griffin or any other Staff witness in that rate case. It appears to AIU

that Staff undertook no such sampling approach, and that Staff based its proposed capital additions adjustments entirely on other audit methods.

In recent cases involving other utilities, AIU avers that Staff has not required invoice-by-invoice support for plant additions. (AIU Initial Brief at 41, citing Docket Nos. 07-0241 and 07-0242 (Cons.) (Peoples Gas Light and Coke Company (~~-Peoples~~)/North Shore Gas Company (~~-North Shore~~)); Docket No. 04-0779 (Northern Illinois Gas Company (~~-Nicor~~)); Docket No. 05-0597 (ComEd); Docket No. 06-0285 (Aqua Illinois, Inc. ("Aqua")); and Docket No. 07-0357 (Mt. Carmel Public Utility Company)) In these cases, AIU asserts that Staff's approach was different than Ms. Everson's approach in this case. AIU believes that in other cases, Staff has not required this level of detail in conducting its review, and the Commission has not required this level of detail in approving other utilities' plant additions.

AIU contends that in Illinois-American Water Company (~~-IAWC~~) rate cases in Docket Nos. 90-0100, 92-0116, 95-0076, 97-0112, 00-0340, and 02-0690, Staff conducted an audit of capital additions, and one of the primary methods Staff relied on in those proceedings was a review of continuing property records, similar to that conducted by Ms. Everson in these proceedings. AIU says that in those cases where that audit method was employed, no further audit procedure was employed. According to AIU, Staff's approach in this case is not only flawed, it is an unwarranted departure from prior rate cases.

Ms. Everson, AIU states, admits that there may be valid reasons why certain invoice amounts do not match amounts on the list of projects that were provided. AIU claims that Ameren Exs. 19.12 and 43.6 demonstrate that there are valid explanations for many of the perceived discrepancies between the invoices and the listing, which casts doubt on Ms. Everson's proposed adjustment. AIU states that certain invoices differed by 1% from the amount presented in the project listing provided to Staff due to a discount extended by the vendor. AIU claims that the evidence it submitted in rebuttal supported the underlying cost directly in response to Ms. Everson's preferred audit approach of reviewing invoices. Where invoices could not be located or another reason was identified but could not be explained within the rebuttal filing deadline, AIU asserts that such costs are supported through other audit approaches, including support provided by the underlying general ledger queries, other project requirements, and continuing property records. According to AIU, Staff has not disputed that any of the underlying costs proposed for disallowance on Ms. Everson's Schedule 2.03 were either not incurred or should otherwise be ineligible for recovery, if the specific reason cited by Staff could be adequately addressed. AIU believes that any adjustments beyond those AIU conceded in rebuttal or in surrebuttal are inappropriate.

AIU states that with respect to Ms. Everson's first six criteria, Ameren Ex. 19.12, Schedules 1 through 6, Ms. Everson lists each invoice disallowed, based on a process of elimination, and a ~~best~~ "best guess" as to the reason for the disallowance. According to AIU, Ameren Ex. 19.12, Schedules 1 through 6 also explain why the disallowance is not appropriate to the extent the explanation is unique or specific to that particular invoice.

AIU adds that Ameren Ex. 43.6, submitted in surrebuttal, updated Ameren Ex. 19.12 and provided more support. For some invoices, AIU says none of the reasons seemed to apply. In those cases, AIU indicated —“Reason” because the invoice was tied to the listing and none of the six criteria could be applied as a rationale for a disallowance. AIU states that there are some instances where AIU either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson. While there are other ways to substantiate these costs, and some of the missing documents can directly be attributed to ownership transaction, AIU says it accepted, for purposes of this rate proceeding, an adjustment to rate base and depreciation expenses. AIU indicates that Ameren Ex. 19.12, Schedules 1 through 6 include a corrected calculation of Staff’s Schedule 2.03 to consider evidence presented in rebuttal and an application of the unsupported percentage to the correct population, as discussed in the rebuttal testimonies of Mr. Taylor and Dr. Batcher.

AIU claims that Staff fails to adequately explain why Ms. Everson could not have used other audit methods to verify plant additions where an invoice was lacking. According to AIU, an invoice is one form of evidence that can be used to support plant addition amounts on the general ledger, but it is not the Holy Grail. In AIU’s view, invoices are not the only appropriate, or even the best, evidence of plant addition costs. (AIU Reply Brief at 14, citing, Preston Utilities Corporation v. ICC, 39 Ill. 2d 457, 460 (1968) (upholding a Commission finding based on the premise that —“the best evidence” of plant costs are —the general ledger, journal entries, and income tax returns”)) AIU says it provided additional supporting documentation in the form of continuing property records, property/retirement unit catalogs, accounts payable records, the contractor system, and vendors’ verifications. According to AIU, Staff’s position is that none of this is a substitute for an invoice. AIU says, according to Staff, if there is no invoice for a project then the costs can not be supported. According to AIU, Staff has, in other cases, relied exclusively on continuing property records, property retirement catalogs, and other forms of non-invoice support to justify plant additions.

AIU alleges that Ms. Everson’s rebuttal testimony does not respond to a large portion of Mr. Stafford’s rebuttal testimony. AIU asserts that the vast majority of the invoices detail explanations Mr. Stafford provided in rebuttal, with the exception of a few specific examples. AIU claims Ms. Everson does not address why she continues to disallow costs where the exact amount of the cost was highlighted on the invoice. AIU contends there are at least 265 invoices totaling about \$1.7 million, with no explanation as to why these costs remain unsupported.

AIU argues that Staff’s failure to review information provided to support plant additions cast serious doubt on the validity of Ms. Everson’s adjustment. AIU asserts that before Ms. Everson filed her rebuttal testimony, AIU supplemented its responses to Ms. Everson’s Data Requests MHE 3.03 and 3.06. AIU claims its supplemental responses modified the amount attributable to electronic transactions. AIU says Ms. Everson refused to incorporate this supplemental information into her analysis.

AIU claims to have been and currently be in compliance with the Commission's document retention requirements. AIU asserts that it has appropriate document systems and controls in place, and has made significant enhancements to its systems and controls. AIU says that Ameren Ex. 52.1 is a detailed description of its project file maintenance procedures. According to AIU, these procedures indicate that it has a proper system for retaining documents in place.

Even if the Commission were to find that AIU is or was not in compliance with Commission rules, taking into consideration that the data and records at issue are largely pre-acquisition, AIU believes this finding would not justify permanent disallowance. Permanent disallowance, AIU argues, is the rate case equivalent of the death penalty. Where rate base items are permanently disallowed, AIU says the utility may never earn a return on or of those items. Permanent disallowance, AIU claims, is therefore reserved for imprudent expenditures. AIU says its research reveals no precedent for permanent disallowance of prudent expenditures based on allegedly deficient documentation. No party to this proceeding, AIU adds, has alleged that any amounts included in Ms. Everson's adjustment represent imprudent expenditures. According to AIU, Staff has offered no support for its assertion that a permanent disallowance can be ordered based on documentation concerns. Because there is no issue in this proceeding concerning the prudence of any expenditures for plant additions, AIU maintains there is no basis in law or fact to permanently disallow rate base recovery of any such additions.

If the Commission feels that AIU has not adequately supported plant additions, AIU says it is prepared to suffer the consequences. While it would be one thing to disallow plant additions in this case, AIU asserts that to permanently disallow any plant additions is entirely different. AIU says it would be forever precluded from earning a return on or of property used and useful in providing service. AIU expresses concern that it would send a message that AIU loses not only in this case, but in all future cases. If any plant additions are disallowed in this case, AIU argues that those additions under the law must be included in rate base in the next case, provided they are adequately supported at that time. (AIU Initial Brief at 47, citing Illinois Power Co., Docket No. 89-0276, Order at 315 (1990))

AIU states that Staff cites no case law or Commission decision to support a permanent disallowance. AIU says it does not dispute that CILCO and IP were public utilities and subject to the Commission's record retention rules. According to AIU, left unsaid by Staff is what current AIU management was supposed to do to ensure that CILCO and IP properly maintained records before Ameren acquired those entities. AIU states that to the extent any violations occurred prior to Ameren's acquisitions, they were committed by the prior owners.

In AIU's view, Staff's recommendation for a fine should also be rejected. AIU claims Staff has ignored evidence provided by AIU that responds to many of Staff's concerns regarding plant records. AIU asserts that most of the difficulties in locating records arose from the fact that two of the utilities were previously under different

ownership. While it may be true that these companies had record keeping obligations before being acquired by Ameren, AIU claims it is equally true that Ameren had absolutely nothing to do with these companies' recordkeeping practices until it acquired the companies. AIU says that Ameren acquired AmerenCILCO in early 2003 and AmerenIP at the end of 2004. While this proceeding deals with projects that went into service by the end of a 2006 test year, AIU asserts that many of those projects included costs, and related invoices, that predated Ameren's acquisitions.

In addition to AIU's lack of control over prior record preservation, AIU says there were also transitional issues, such as IP's use of a particular electronic document system that was taken out of service when AmerenIP was integrated into the Ameren system. With respect to AmerenCILCO, before the acquisition by Ameren, AIU claims there were two different systems in place. Prior to the acquisition of CILCO by AES in late 1998, AIU says invoices were centrally processed by a corporate Accounts Payable department. This is consistent with the system utilized by AIU. Starting in 1999 under AES' ownership, in addition to a small centralized accounts payable group that processed electronic payments and miscellaneous invoices, AIU says decentralized accounts payable processes were set up at the Duck Creek, Edwards, Springfield, Persimmon Gas, and Pioneer Park Electric areas. AIU states that each area received its own invoices and had separate checking accounts to pay vendors. AIU adds that all five areas were also responsible for bank reconciliations as well as retaining and storing their checks, bank statements, and invoices. According to AIU, the invoices at Pioneer Park Electric were housed in boxes in the storeroom and erroneously discarded after the acquisition by Ameren. AIU indicates it is not aware of any systemic loss of AmerenCILCO invoices other than those destroyed at Pioneer Park Electric. AIU states that for AmerenCILCO, 100% of the transactions sampled by Ms. Everson occurred prior to the acquisition of CILCO by Ameren.

Although AIU believes the Commission should reject the recommendations for fines and permanent disallowance, AIU says it has no objection to a requirement that it subject its document processing and retention for plant additions and retirements to an internal audit. AIU says that Ameren's internal audit department already reviews these matters annually, and works with its outside auditors to review document processing and retention. AIU indicates that Ameren Ex. 52.2 is a detailed outline of the most recent review. In addition, AIU says that it has already asked internal audit to review the issues surrounding the CILCO pre-acquisition document loss and make any appropriate recommendations.

AIU further claims that Staff's call for penalties fails to recognize that AIU is already being penalized. AIU states that all of the assets have already been in service since 2006 or earlier, and it will not earn a return on such assets until at least October 2008. In light of this fact, AIU contends that permanent disallowance and/or fines would be excessive, confiscatory, and unwarranted. In response to Staff's claims that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these additions, AIU suggests that Staff review the information

already provided in Ameren Exs. 19.12 and 43.6. AIU insists that the information supporting plant additions is available today.

In response to Staff's suggestion that permanent disallowance is warranted to provide AIU with the incentive to adequately support plant additions and to make AIU accept responsibility, AIU says it has done nothing wrong. AIU suggests that to the extent the Commission believes otherwise, the remedy is to disallow certain plant additions in this case. AIU claims it would have an incentive to document plant additions in a manner acceptable to the Commission in the next case in order to recover the costs of those additions. AIU maintains that if it provides support for these additions in the next case, it is legally entitled to recover the costs, regardless of the outcome in this case.

In response to Staff's assertion that AIU's records are in remarkably poor condition, AIU alleges that Ms. Everson is in no position to make such a claim. AIU says she did not perform her review at AIU's offices and does not otherwise have any basis to pass judgment on how AIU keep its records. AIU states that her assessment is based solely on what AIU provided to her during discovery in this proceeding. According to AIU, Staff is free to criticize the format in which information was provided in discovery, but there is no record support for the statement that the manner in which information was produced in discovery is reflective of how records are compiled and maintained at AIU's offices.

In AIU's view, Staff overplays the effort needed to review the information provided by AIU. The volume of information involved, AIU claims, is a direct reflection of the scope of Staff's adjustment. According to AIU, whether Staff has thoroughly reviewed it or not, this evidence should not be ignored.

AIU contends that Staff attempts to reverse the burden of proof. In AIU's view, Staff's arguments and position in this case seem to ignore the fact that invoices offer additional support for general ledger amounts – not the other way around. AIU says its books are regulated, and audited, and are evidence in and of themselves of AIU's costs. According to AIU, Staff has ignored the significance of AIU's audited records, the controls that are in place, and the existence of the plant additions themselves. AIU complains that Staff's proposed adjustments would effectively disallow from rate base approximately \$150 million in plant additions while AIU believes the correct adjustment is approximately \$25.6 million.

AIU disputes Staff's claim that providing Ex. 19.12 during rebuttal constitutes a deliberate attempt to withhold information. AIU asserts that this information was provided in direct response to Staff's direct testimony recommending the disallowances. AIU says it had no motive to withhold information that supports plant additions. AIU argues that considering the experience in prior cases, AIU had every reason to be as above-board with Staff as possible in this case.

In response to Staff's complaints about receiving information after Staff's rebuttal, AIU claims that is the point of surrebuttal. In AIU's view, there is nothing improper about providing surrebuttal evidence that is responsive to Staff's rebuttal testimony. AIU says the surrebuttal evidence was put forth specifically to rebut the positions taken by Staff in its rebuttal.

Staff suggests that its original proposed adjustments should be adopted unless the decision maker conducts an analysis of the information provided in Ameren's surrebuttal testimony. AIU says it agrees that the Commission should analyze its surrebuttal evidence. According to AIU, the fact that it may be time consuming and meticulous to review the data is not a reason to ignore it. AIU claims it would not be nearly as time consuming and meticulous to review AIU's evidence as Staff would like the Commission to believe.

AIU says with regard to Ameren Ex. 43.6, Staff basically suggests that the information in this exhibit should be ignored because it is too hard to figure out. AIU agrees that this exhibit is hard to figure out if reviewed in the manner that Staff suggests and as described in Staff's Initial Brief. AIU states that Ex. 43.6 updates, corrects, and supplements Ameren Ex. 19.12. AIU alleges that Staff's apparent objective is not to determine whether Ex. 43.6 supports the requested level of plant additions, but whether the information provided as new information in surrebuttal was not in fact duplicative of earlier productions. AIU claims that Staff spent an afternoon cross-examining Mr. Stafford about discrepancies as low as \$2.55 and \$2.32. According to AIU, approximately 98% of the evidence was in Staff's hands after AIU submitted its rebuttal testimony. AIU asserts that even if Ameren Ex. 43.6 is not considered, Ameren Ex. 19.12 largely stands on its own in support of the requested level of plant additions.

Staff argues that the Commission should disregard the vendor supplied invoices contained in Ameren Ex. 42.2. First, AIU says Staff argues that some of the invoices contain amounts that do not agree with the summary listing. AIU claims that AIU witness Nelson explains why the amounts are different. Second, AIU says Staff complains that the affidavits are hearsay. AIU responds that they are part of the record. Third, AIU says Staff does not like how some of the invoices are worded. AIU asserts that regardless of how they are worded, the affidavits support the amount of AIU's plant additions.

According to AIU, Staff also attempts to create an issue from the fact that certain invoices were mistakenly billed to the wrong AIU entity by contractors. AIU suggests that the Commission understands that each of the utilities is a separate legal entity with separate books and records. AIU claims the significance of this legal separation is not always apparent to contractors that perform work for AIU. AIU states that its project managers make sure that invoices are assigned to the proper utility and project. In AIU's view, that this explanation is not apparent from the face of an actual invoice is of no import. That, AIU argues, is the reason why the project manager follows up to make sure the proper company is charged.

AIU understands Staff's position to be that if Staff could not read an invoice, the amount supported is \$0. AIU suggests that Staff could have advised it that there were certain invoices that were illegible, but Staff never did so. AIU claims that had Ms. Everson promptly made known that she could not read some of the invoices, AIU would have quickly provided better copies. AIU says when this issue was made known to it, Mr. Stafford provided legible copies.

AIU states that where invoices did not match the summary listings, Staff proposes to disallow the entire invoice amount. AIU maintains that there could be legitimate reasons for the differences. This being the case, AIU believes it is not unreasonable to expect Staff to make some effort to determine whether such a legitimate reason exists. AIU suggests a good place to start would be to identify to AIU which invoice amounts do not match the summary listing. AIU says Staff never did so, claiming it has no obligation to further expend its limited resources to help AIU satisfy its burden of proof. AIU insists that Staff has the burden to produce evidence to support its adjustments. AIU says it provided responsive evidence that proves, despite differences between invoice amounts and amounts on the summary listing, the reasonableness of the addition.

AIU also claims that many of the differences are a few dollars. AIU states that Voucher #003347 associated with AmerenCIPS project 16895 is an invoice for \$391.08. AIU believes that Ms. Everson disallowed this invoice because the amount presented on the summary was \$387.17. AIU claims the difference is attributable to a 1% discount for early payment.

In response to Staff's assertion that AIU never provided evidence to substantiate its purchasing rate policy, AIU claims it produced detailed schedules identifying each discrepancy attributable to a purchasing rate. (Ameren Exs. 19.12 and 43.6) In addition, AIU says it responded to Staff Data Request 12.05 by providing a copy of AmerenCIPS purchasing rate policy in effect during June 2004. AIU complains that Staff did not issue any further Data Requests to better understand how AIU's purchasing rates worked. AIU further complains that unlike the prior rate case, in which Staff had discussions with AIU regarding purchase rates to obtain a better understanding of how such rates worked, Staff made no such effort to understand purchase rates in this case.

With regard to invoices that included finance charges, AIU complains that Staff attempts to make a mountain out of a mole hill. AIU says there is no list of which invoices included finance charges. Ms. Everson agrees that it is reasonable to ensure that an invoice amount is appropriate before paying the invoice. AIU states that if being reasonable ultimately results in the imposition of finance charges, so be it. AIU notes that where invoice amounts differed because of the application of a discount for early payment, Ms. Everson excluded the entire invoice because of the perceived discrepancy.

AIU asserts that it learned for the first time, through Staff's Initial Brief, that employee meals are another category of expense items that Staff disallowed. According to AIU, Staff relies on the fact that, while on the stand, Mr. Stafford could not cite a definitive reference from the Uniform System of Accounts ("USOA") indicating that employee meals may be capitalized as part of plant additions. According to AIU, the USOA does support the capitalization of employee meals. Specifically, Electric Plant Instruction 3, under —Components of Construction Costs," establishes that —Labor includes the pay and expenses of employees of the utility engaged on construction work." (18 CFR § 101 (emphasis added); 83 Ill. Admin 415.430.)

AIU says Staff's position on electronic transfers is based on its review of Ameren Ex. 19.13, which provides in spreadsheet form a description of electronic transactions. AIU states that contrary to Staff's assertion that this information came from the general ledger, Ex. 19.13 came from a separate system that contains information above and beyond the information contained in the general ledger. AIU complains that Staff fails to mention that AIU witness Livasy submits Ameren Ex. 61.1, which provides printed copies of invoice records maintained in AmerenIP's electronic transaction records. AIU says it is true that AIU believed that these records could not be retrieved from a legacy system; however, the records have since been retrieved. AIU claims the records should not be ignored. AIU further claims that all of the information necessary to support the electronic transactions, which total approximately \$1.5 million, is contained in Ameren Ex. 61.1.

With respect to the 2004 IP gas historical plant additions, Staff claims that despite the fact that IP was allowed a certain level of 2004 pro forma plant additions in the last rate case, it is appropriate to disallow 2004 plant additions in this case. AIU believes Staff's arguments are misguided because some of the costs approved by the Commission in the prior case were actuals, not estimates. AIU claims Schedule 14.03 IP G shows \$33.522 million of additions used in Staff's calculation of its unsupported percentage. AIU states that a review of IP Ex. 12.4 in Docket No. 04-0476 shows that over \$25 million was in service at time of review and, therefore, not an estimate. AIU also asserts that \$16.982 million of Completed CWIP Not Transferred to Plant in Service were also actuals, not estimates. AIU says these amounts combined exceed the \$33.522 million of additions Staff used in its calculation.

b. Staff's Position

Ms. Everson reviewed AIU's 2003 through 2006 plant additions which it seeks to include in rate base. The objective of such a review, Staff says, is to establish whether the underlying costs for such plant additions are adequately supported by documented evidence. Staff believes that the required support for these plant additions were either deficient in many respects or non-existent. Staff developed a sample of projects for each of the six utilities that were based on Ms. Everson's professional judgment, knowledge, and experience as an accountant. Specifically, for each of the six utilities, she reviewed and analyzed the invoices and the summary listings that were associated with projects having a total dollar value greater than \$500,000. Ms. Everson made the

assumption that more care and documentation would be given to projects with a larger cost than those with smaller costs; thus, better records would be available to support the larger projects. For each of the six utilities, Ms. Everson developed a sample for which she determined the percentage of unsupported project costs to the total costs of the projects within the sample. The resulting company-specific percentage of unsupported costs was then applied to the total 2003-2006 plant additions for the respective utility to determine the amount of Staff's proposed plant disallowance.

Staff says its review of over 8,700 pages of project invoices and listings that summarized the amounts of such invoices recorded by AIU (referred to by Staff as —summary listings”) resulted in the discovery of numerous problems. According to Staff, adequate support for the plant costs was non-existent or had one or more of the following deficiencies: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that did not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice.

According to Staff, the company-specific percentages of unsupported plant costs are as follows: AmerenCILCO gas: 11.58% electric: 35.45%; AmerenCIPS gas: 25.56% electric: 2.35%; AmerenIP gas: 51.74% electric: 12.78%. Staff states that when these percentages are applied to the respective totals for plant additions from 2003 through 2006, these percentages result in the following proposed plant disallowances: AmerenCILCO gas: \$6,563,000 electric: \$30,005,000; AmerenCIPS gas: \$1,736,000 electric: \$2,347,000; AmerenIP gas: \$49,810,000 electric: \$34,135,000.

According to Staff, AIU's failure to properly document plant additions has a long and contentious history. Staff states that in Docket No. 99-0121, the Commission Order demonstrates CILCO's inadequate support for its pro forma plant adjustments and the untimely production of such information to Staff. Unlike in the current docket, however, Staff says CILCO accepted responsibility in that rate case for its failure to provide the appropriate documentation for its plant requests and recognized it should bear any hardship for failing to provide such documentation. (Staff Initial Brief at 10-11, citing Docket No. 99-0121, Order at 22-27 and 29-30)

Staff claims that in its last electric delivery services rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), AIU again failed to provide sufficient documentation to support its plant costs. Staff states that in those consolidated dockets, the Commission imposed a plant disallowance due to AIU's failure to support its plant additions. (Staff Initial Brief at 11-12, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 13 and 7) Staff says its proposed disallowances in that case were related solely to disputes over documentation of AIU's reasonably incurred costs.

Staff asserts that in the current proceeding, the same pattern from prior rate cases repeats itself. Staff says that in the MHE 3 series of data requests (Staff Data

Requests MHE 3.01-3.06) Staff requested copies of invoices, a listing of invoices, and all loading factors for the projects chosen for the sample for each of the six utilities. AIU provided six compact discs (“CDs”) in response during December 2007 through February 19, 2008. Staff indicates that the CDs contained approximately 8,700 pages of documentation, including the summary listings and copies of invoices. Staff adds that the response on February 5, 2008, dismissed the request for all loading factors as being —. . . unduly burdensome and unreasonably time consuming Further, the information is not relevant, nor material, nor likely to lead to the discovery of admissible evidence.” (Staff Initial Brief at 12-13, citing Staff Ex. 14.0R, Att. A) Staff says it understood this to be the entirety of support that AIU could provide for the sample of plant additions. The information in the six CDs and the narrative response to the MHE 3 series formed the basis for Staff’s analysis and recommendation.

Staff claims that AIU’s initial productions in discovery did not contain all of the requested documentation, nor, in Staff’s view, did it contain sufficient documentation for the plant costs it seeks to recover from ratepayers. Staff complains that AIU provided additional information in its rebuttal testimony that should have been provided earlier in the case when such information was requested by Staff. Staff says Ameren Ex. 19.12 includes a detailed listing that attempts to provide a reason why AIU considered disallowed amounts as supported. For some line items on Ameren Ex. 19.12, Staff says AIU indicates: —[c]an’t locate the invoice.” (Staff Initial Brief at 13, citing Ameren Ex. 19.12, Sch. 1-CILCO-E, at 10-12.) Staff adds that Ameren Ex. 19.12 also includes Schedules 8-13, provided on a CD which contained 83 separate pdf files, containing invoices and supporting documentation as requested in the MHE 3 series of data requests, named by schedule and part. In Staff’s view, the provision of this volume of information without a clear organizational framework at the rebuttal stage of the proceeding made it impossible for Staff to complete a thorough review.

Staff says it reviewed a sampling of the information provided in Ameren Ex. 19.12 and sent data requests to AIU. Staff claims the data requests sought information regarding the explanations provided in Ex. 19.12 to attempt to determine if the explanations were indeed the reasons why the invoice amounts and AIU’s summary listings did not match. Staff asserts that AIU’s data request responses were vague and in some instances contradicted Ex. 19.12, and failed to fully reconcile the differences between the invoice amounts and the amounts shown on the summary listings. One of the reasons provided with Ameren Ex. 19.12 for the mismatch between the summary listings and the invoices, Staff states, were —purchase adders.” Staff claims that AIU never provided any information as to what the appropriate purchase adder was for AmerenCILCO and AmerenIP. According to Staff, AIU provided no indication of what the fixed rate charge was or when it would be applied.

Staff argues that by providing information in rebuttal testimony rather than in responses to discovery, AIU has deliberately attempted to withhold information to support its request for recovery of plant additions in an adequate and timely manner. Such litigation strategy, Staff contends, is a common theme in the prior AIU cases.

Staff believes the Commission has given AIU more than enough warnings and must hold AIU accountable for the consequences of its actions.

Staff states that when it requested a separate identification of the type and amount of all loading factors in connection with its review of plant additions, AIU protested that this would require an examination of each invoice. Staff says it accepted AIU's explanation that this would be unduly burdensome and time consuming. Staff, however, claims that it could not accept invoices as support for a different level of costs than was reflected on the invoice. According to Staff, AIU claims it provided Staff with the information necessary to complete a review of plant additions; however, Staff says AIU did not provide it with sufficient information to support all of the plant additions that AIU proposed be included in rate base. Staff argues that it does not know what documentation AIU possesses or the level of burden of producing the documentation. According to Staff, AIU knows what documentation it possesses, the difficulty of producing it, and the consequences of failing to produce support for its plant additions.

Staff asserts that AIU is aware that unsupported plant additions will not be included in rate base, and is aware of the importance of locating and producing support for plant additions. Staff contends that if AIU deems support to be overly burdensome to provide, Staff can complete its analysis without the additional documentation but, since costs can not be included in rate base unless they are supported, the failure to provide support will inevitably result in adjustments. According to Staff, AIU's provision of breakouts of the costs associated with each project in response to Staff data requests MHE 3.01-3.06 was an ineffective substitute for providing the loading factors. Staff states that gross loading factors were provided, not specific amounts for individual line items for which there were differences between the line item on the summary listing and any invoice. In Staff's view, it was not clear how much of the gross amounts in the breakouts related to such items and how much related to items for which no supporting document was provided.

Staff also argues that compliance with initial filing requirements does not equate to bearing the burden to prove plant additions. Neither, Staff says, does supplying additional information in response to Staff Data Requests and in rebuttal and surrebuttal testimonies necessarily prove the plant additions. According to Staff, it is not the quantity of documents produced or the timing of when the documents are produced that determines whether AIU has met its burden of proof. Staff states that the plant additions for which AIU provided invoice-by-invoice support were allowed by Staff.

According to Staff, AIU is apparently claiming that it has made a showing of the costs necessary to provide service by providing the minimum filing requirements and what amounts to a mountain of paper. Staff states that Part 285 simply provides the minimum filing requirements. Staff argues that providing large quantities of documents that can not be reconciled to the general ledger is not sufficient to satisfy AIU's burden of proof under Section 9-201(c) of the Act. Staff claims the documents AIU provided to support plant additions were replete with deficiencies.

In Staff's view, AIU's reliance on City of Chicago for the premise that it need only make a —showing” of the costs necessary to provide service is misplaced. Staff states that AIU is proposing to include plant additions, for which it failed to provide support, in rate base. Staff argues that absent external support, AIU has not shown by a preponderance of the evidence that plant additions are reasonable. Staff also refutes AIU's reliance on Docket Nos. 83-0537/84-0555 (Order at 183-184). Staff insists there is no presumption of reasonableness.

Staff says AIU argues that the basis for Staff's plant additions adjustment is only because of issues pertaining to the documentation of expenditures. AIU, Staff adds, distinguishes this adjustment from one based on a cost being imprudent or unreasonable. Staff calls this hair splitting. Staff repeats that utilities are required to retain records and to support costs for a reason.

Staff asserts that AIU is in violation of 83 Ill. Adm. Code 420, —The Preservation of Records of Electric Utilities” (Part 420”), and 83 Ill. Adm. Code 510, —The Preservation of Records of Gas Utilities” (Part 510”). Staff states that the rules require that the detail summary and distribution records supporting journal vouchers for plant accounts be retained for the seven years prior to the date as of which the original costs of plant have been unconditionally determined or approved by the Commission.

Staff says AIU attempted to excuse its failure to retain its records and to support its costs by pointing to different corporate ownership of CILCO and IP prior to their acquisition by Ameren. Staff says the implication of AIU's statement is that this somehow absolves it of its record preservation obligations. Staff states that each of the acquired AIU companies was a public utility company prior to Ameren's acquisition and AIU operated AmerenUE in Illinois prior to merging with the other public utility companies.

According to Staff, AIU complains that Staff refused to take into consideration the timing of the transactions and the changes in systems and corporate ownership when recommending a disallowance due to missing invoices or unsubstantiated amounts. Staff says AIU has made this claim in two prior rate cases, one as far back as 1999, and in each case, this excuse was rejected by the Commission. Staff argues that it is irrelevant that AIU had no control over the actions of the prior owners. Staff says that when AIU was seeking approval of its reorganizations, it committed to be subject to all of the rules and regulations and should be held to its commitment.

Staff adds that AIU failed to notify the Commission within 90 days of the destruction or loss of such records, as required by Section 420.70 of Part 420 and Section 510.70 of Part 510. Instead, Staff asserts that only after it raised this as an issue did AIU provide the required notice to the Commission that CILCO's September 2000 through December 2002 accounts payable vouchers were prematurely destroyed in September 2003. Staff states that this notice was provided to the Commission significantly beyond the 90 days required by Sections 420.70 and 510.70, and it does

not cover other documents that AIU has been unable to provide for AmerenCIPS and AmerenIP for which no explanation has been provided.

Staff states that although AIU witness Steinke admits that it must accept responsibility for its inability to produce plant cost documentation sought by Staff in this case, he also claims that AIU is in compliance with the Commission's requirements for preservation of records. According to Staff, AIU can not have it both ways: pretending to accept its responsibility for its failure to produce records and then claiming it is in compliance with the Commission's record retention policies.

Considerable resources, Staff contends, have been spent in this proceeding to provide, explain, and review AIU's support for plant addition costs since its last rate case. Staff maintains that AIU has failed to retain and produce records it is required by administrative rule to preserve. Staff adds that in some circumstances AIU relied upon third parties' records. Staff says that in other circumstances, AIU retracted previously supplied explanations for discrepancies in its documentation. Staff believes that AIU is unable to adequately explain all the discrepancies between its plant invoices and the summary listings. As a result, Staff contends that there is doubt as to whether any of the information provided on Ameren Ex. 19.12, or in exhibits attached to its surrebuttal testimony can be relied upon. Staff argues that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these plant additions. Staff claims the support should have been generated at the time the plant was added and there would be no reason that the support was not available in 2008, but would be available in 2009 or 2010. Staff recommends that AIU permanently write-off all plant disallowance amounts ordered in this proceeding and be prohibited from seeking recovery of these amounts in any future rate proceeding. Staff believes a permanent disallowance will close the book on the matter allowing AIU and Staff to focus on more timely issues in the next rate case.

According to Staff, the only argument Mr. Steinke offers to rebut Staff's recommendation of a permanent disallowance is to state that such a disallowance is unduly harsh and would not be a positive event for AIU. Staff maintains this is not the first or second instance in which AIU was put on notice that it must fulfill its responsibility to support its request for recovery of plant costs with adequate and timely documentation. Staff asserts that AIU has failed to do so time and again and in a significant manner. Staff claims the magnitude of the apparent disarray in AIU's records has resulted in the Staff proposed disallowance. Staff maintains that there is no reason to believe that documents unavailable now will materialize before the next rate case.

To provide AIU with a clear incentive to fulfill its obligation of adequately supporting plant costs for which it seeks rate recovery, Staff urges the Commission to permanently disallow unsupported plant costs in this proceeding. Staff asserts that a permanent disallowance would make AIU truly accept its responsibility by accepting the consequences of its failure to retain and/or produce records. To do otherwise, Staff argues, would be tantamount to encouraging AIU to continue the same pattern it has followed over the years of providing inadequate information to support costs that it

seeks to have ratepayers pay. In addition, Staff asserts that failure to order a permanent disallowance would allow AIU, in the next rate case, to focus on producing documentation for the plant additions added subsequent to this proceeding.

According to Staff, if the Commission were to allow unsupported costs to remain in the AIU plant accounts, those same disallowed plant costs would be included in rate base in all future rate proceedings. Staff alleges that all future proposed revenue requirements would include a return on what it calls phantom plant and a recovery of the phantom plant through depreciation expense. Staff asserts that a permanent disallowance of the costs would remove the costs from the AIU plant accounts thus removing this possibility.

In its Reply Brief, Staff states that, generally, the plant in service balance should always be determined by beginning with the last original cost balance ordered by the Commission, adding properly supported plant additions and subtracting documented retirements. Staff asserts that to start with a number that includes plant additions that the Commission found to have deficient documentation in a previous case improperly ignores and overrides the previous Commission order.

Staff claims that the notion that the Commission has not ordered permanent disallowances for lack of documentation does not bear scrutiny. Staff says the Commission in four previous dockets made adjustments for unsupported plant additions due to poor or non-existent utility records. According to Staff, the effect of these orders is a permanent disallowance since the records were found to be non-existent or so deficient that the plant additions can not be substantiated at the time of the orders or in a subsequent proceeding.

Staff states that in Docket No. 04-0610, a rate proceeding of New Landing Utility, Inc., the Commission laid out how the plant-in-service balance is determined:

Staff witness Griffin calculated utility plant by beginning with the allowed level of Utility Plant for ratemaking purposes found in the previous rate case. (See 79-0676/79-0675 (Cons.) at 11, 15 (Jan. 14, 1981)). Plant additions supported by documentation were added to the water and sewer rate bases. . . . Having reviewed the entire record in this proceeding, the Commission cannot accept the AG's proposal to utilize the Company's Annual Report as the basis for establishing rate base in this proceeding. It is clear that NLU's accounting procedures and records since the last rate case are flawed. Contrary to the AG's suggestion, the Commission simply cannot rely upon NLU's annual report and underlying accounting records to set rates in this proceeding. Thus, Staff's recommended approach to establishing rate base in this proceeding is adopted. (Order at 4-5)

In Docket Nos. 03-0398/03-0399/03-0400/03-0401/03-0402 (Cons.), a rate proceeding of Cedar Bluff Utilities, Inc., Apple Canyon Utility Company, Charmar Water Company, Cherry Hill Water Company, and Northern Hills Water and Sewer Company,

Staff says the Commission adjusted the current revenue requirement to reflect previous disallowances made by the Commission in the previous rate case. The order states:

Staff proposed adjustments to reflect rulings in previous Commission Orders. (Staff Group Ex. 2.0). These adjustments reduce rate base for Apple Canyon and Charmar. These adjustments also incorporate adjustments that were never made from the Commission's order in Docket No. 90-0475/92-0401, which concerned Apple Canyon, and Charmar's short form filing with a test year ending December 31, 1989. The Companies did not contest the adjustments. (Order at 12)

Staff claims the order also lends support that the Commission expects plant additions to be supported by documentation as the language below indicates:

Staff proposed adjustments to reduce the test year plant amount to reflect those additions and retirements that the Companies could not verify. (Staff Group Ex. 2.0). These adjustments decreased plant for Cedar Bluff, Apple Canyon and Charmar. Cedar Bluff's test year plant was reduced by the amount of additions and retirements, for which, it could not provide any supporting documentation. Both Apple Canyon's and Charmar's test year plant were reduced by the amounts of additions, for which the Companies could not provide any supporting documentation. Corresponding adjustments to accumulated depreciation, depreciation expense, and accumulated deferred income taxes were also made. The Companies did not contest any of these adjustments. (Order at 11)

In Docket No. 98-0045, a rate proceeding for Northern Hills Water Company, Staff claims the order refers to the company recording plant adjustments permanently on its books and records for adjustments from the prior rate case not reflected in the company's filing:

The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and on Appendix C, Schedule 4. The Company agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 4)

In Docket No. 98-0046, a rate proceeding for Del Mar Water Corporation, the Order states:

The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and it agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 3)

Staff believes a permanent disallowance would make it clear to AIU that it can not continue to promise to do better, but continue to fail to comply with Commission rules.

AIU witness Taylor claims that Ms. Everson's sampling methodology was flawed since the entire population of plant additions was not sampled. Staff states that Mr. Taylor conceded that it is not within the scope of his testimony to review the legitimacy of Staff's conclusions regarding plant additions. According to Staff, AIU witness Batchner criticized Ms. Everson's reliance upon a judgmental sample since unlike statistically based random samples, accuracy of judgmentally selected samples can not be assessed in a scientific or objective manner.

Staff states that in performing her plant additions analysis, Ms. Everson narrowed her review to projects \$500,000 or more because she expected, based upon her professional experience, that these larger projects would have better documentation and cost support than would smaller projects. Staff argues that in limiting her sample to the larger projects, Ms. Everson's recommended adjustment to AIU's plant is conservatively low. In Staff's view, if Ms. Everson's analysis is to be faulted, it should be faulted for perhaps not recommending a greater disallowance.

Staff claims AIU has the burden of proof to show that the application of Ms. Everson's judgment and experience has led to an incorrect result. According to Staff, AIU did not provide any evidence to show that had Ms. Everson utilized a statistical sample, the resulting disallowances would be materially different than what has been recommended by Staff.

In its Reply Brief, Staff claims that AIU's position on statistical sampling and on extrapolating the result of an analysis on a sub-group of a population to the larger population that was not statistically sampled directly conflicts with its own method for analyzing the reasonableness of AMS costs allocated to AIU. Staff states that in his study of AMS services and costs, AIU witness Adams chose a sample of 197 service requests ("SRs") out of 881 SRs with allocation factors that affected AIU. Staff says he selected his sample by choosing SRs that had charges allocated to Administrative and General ("A&G") accounts and that totaled more than \$50,000. Staff states that Mr. Adams used the results of his analysis of this judgmental sample from a sub-group of the population to assess the reasonableness of AMS' costs allocated to each of the Ameren subsidiaries. Staff says the basis for the \$50,000 criterion was his professional judgment. According to Staff, Mr. Adams assumed that if the larger dollars are being charged and allocated in an appropriate manner, that everything under \$50,000 was as well. Staff contends that this judgment is similar to Ms. Everson's reliance on her experience and judgment that the larger projects would have better documentation and cost support than would smaller projects. Staff argues that since AIU continues to assert that Mr. Adams' AMS analysis should be relied upon by the Commission, it can not dismiss Ms. Everson's plant additions analysis.

Staff states that while Ms. Everson prepared no written plan that does not mean that no plan was developed prior to her review of plant additions. Staff says it requested and received a listing of projects of \$500,000 or more prior to selecting its sample or conducting its review. Staff claims its request for information regarding plant

additions projects with a total greater than \$500,000 demonstrates that a plan existed to review plant additions projects with a total greater than \$500,000. In addition, Ms. Everson indicated that she determined based on her experience at the Commission that it is reasonable to expect that more care in documentation is given to larger projects than to smaller ones; thus, better records would be available to support the larger projects.

In its Reply Brief, Staff says AIU's assertions regarding the differences between Staff's review in this case being different from any other case is speculation and should not be accorded any weight. Staff claims that although AIU does not admit it, a very similar review was conducted in its last rate proceeding where plant additions were subject to a disallowance for lack of supporting documentation. Staff also believes it is not appropriate for each of Staff's reviews to be constrained by that which has been performed in prior cases. According to Staff, AIU is attempting to convey the notion that not only should Staff's review in this case follow the same review as in the cases it cited, it is also claiming that Ms. Everson's adjustment must be disallowed since it was at odds with other Staff witnesses in this case. Staff contends this claim is irrelevant because Ms. Everson's review concerned whether AIU had sufficient documentation to support its plant additions, whereas Mr. Rockrohr's adjustments to plant additions concerned whether plant held for future use should be included in rate base and whether AIU was prudent in its purchasing of certain security installations. Staff claims that since the focus of each review was different, it is unrealistic to contend that one Staff member's analysis is flawed because it is different from another analysis conducted by another Staff member.

According to Staff, AIU witness Stafford incorrectly criticized Ms. Everson for including AmerenIP's 2004 gas plant additions when she applied the disallowance adjustment percentage to the total plant additions. He argued that IP was allowed a certain level of pro forma plant additions in its last rate case, Docket No. 04-0476. Taken to its logical conclusion, Staff says this argument incorrectly asserts that approved pro forma plant additions in a prior rate case do not require substantiation with supporting cost records in the next rate case. In Staff's view, this argument is unreasonable and inconsistent with the Commission's practice. Staff argues that pro forma amounts are essentially estimates of plant costs expected to occur within a defined period from the chosen historical test year and subject to certain restrictions as defined in 83 Ill. Adm. Code 287, —~~Rate~~ Rate Case Test Year." Staff claims the pro forma amounts for a specific plant can and do vary from the amount actually incurred for the same plant. Staff believes that the prior approval of a plant's cost when it was a pro forma item in a prior rate case has no bearing on its approval as an actual plant cost in a later rate case. In Staff's view, all plant costs for which a utility seeks rate recovery needs to be adequately supported regardless of whether they were once approved as pro forma amounts.

The amounts in the current filing for AmerenIP's 2004 plant additions, Staff argues, are not the same pro forma amounts that were allowed in the prior rate case. Staff says those amounts were allowed as pro forma amounts that would be placed into

service after the 2003 test year in that docket. Staff adds that AIU's response to Staff Data Request MHE 14.01 stated: —The current IP Gas 2004 capital additions amounts included in the current IP Gas filing are not identical to the pro forma plant additions that were considered in Docket No. 04-0476. The amounts related to the IP Gas 2004 capital additions included in the current filing include actual expenditures incurred in both 2003 and 2004 and placed in service in 2004.” (Staff Initial Brief at 24, citing Staff Ex. 14.0R at 25) Staff maintains that its application of the adjustment percentage to all of AmerenIP gas plant additions is appropriate, since the plant additions in this case represent actual project costs which are not the same amounts as the pro forma amounts allowed in Docket No. 04-0476.

Staff states that in its review of the invoices and summary listings reflecting the invoices recorded by AIU, duplicate amounts were noted and disallowances were proposed. Ameren witness Batcher criticized Ms. Everson, for allegedly failing to document her procedures for identifying duplicate invoices rendering AIU unable to determine if she conducted adequate searches to find an adjustment to the duplicate on the summary listings. Staff asserts that Ms. Everson fully described in her rebuttal testimony the type of review she performed to make the determination that there was a duplicate invoice for which no offsetting adjustment existed on the summary listing. Staff asserts that Ms. Everson's review included a comparison of a suspected duplicate invoice with the previously reviewed invoice to verify the identical invoice, number, date, vendor, amount, and service or goods provided. Staff finds AIU's criticism to be without merit.

AIU, Staff argues, essentially faults Staff for not granting it the benefit of the doubt when Staff disallowed invoices that were not billed to the correct entity. Staff says that AIU cites the alleged practice of the IRS. Staff claims that AIU does not appear to fully understand that it is AIU's responsibility, not Staff's, to prove that the invoices it proffers as support for costs it seeks to recover from ratepayers are legitimate.

In Staff's view, the problem with AIU's position is apparent in Mr. Stafford's testimony that an invoice sent to AmerenCIPS but later charged to AmerenCILCO contained nothing that would indicate the invoice should have instead been sent and billed to AmerenCILCO. (Staff Initial Brief at 25-26, citing Staff Cross Ex. Stafford 1 and Tr. at 430-433) Staff provides another example where an invoice sent to Ameren Energy Resources' Purchasing Department but charged to AmerenIP contained no information indicating AmerenIP was the correct entity to be billed (Id., citing Staff Cross Ex. Stafford 2 and Tr. at 433-436) Given the dearth of information on the invoice as to which entity should correctly be charged, Staff argues that it can not in good conscience give AIU the benefit of the doubt and assume incorrectly billed invoices are automatically legitimate.

According to Staff, AIU claimed that the project manager determined whether billings to another Ameren company were appropriately associated with a particular project. Staff says that Mr. Stafford, however, stated on cross examination that there is

no information discernable from a review of the invoice to support this explanation. Staff says that unlike AIU, it can not presume that any review was performed or that any project manager direction was provided to substantiate AIU's claim. Staff asserts that no supporting documentation in the form of source documents, such as invoices that are either marked by the project manager or the accounts payable personnel, or some other internal document that would indicate the project manager's decision regarding which projects to assign costs was provided. Staff says AIU also inappropriately suggests that since the work was performed for the benefit of an AIU utility, it does not matter that an AmerenCILCO customer might be charged for project costs that benefit AmerenIP. Staff disagrees with that view and believes that ratepayers of one utility should not be penalized with higher rates as a consequence of AIU's failure to demonstrate that costs are recorded to the right utility.

According to Staff, Dr. Batchner also fails to recognize that there is a substantial difference between expense payments for tax purposes and the proof needed for rate recovery. For tax purposes, Staff says it makes little difference which company makes payment where a consolidated tax return is filed because in the end, all revenues and expenses are combined into a single tax return. Staff argues, however, that the Commission review for setting rates is a different standard. The Commission, Staff says, must decide which of the six AIU operations is to be credited for payment. Additionally, Staff says a decision must be made whether the payment is to be classified as an expense or a capitalized item. Staff asserts that if the payment is classified as an expense, questions concerning whether it is reflective of normal operations, whether it should be amortized, and whether the unamortized balance should be given a return must be answered. If the payment is classified as a capitalized item, Staff says decisions concerning the proper account and the depreciable life for purposes of calculating annual depreciation expense must be answered. Staff claims its task is more complex than just confirming payment by any one of the utilities and can not be accomplished unless the individual utilities provide the appropriate records in a timely manner.

Staff asserts that in many invoices it reviewed, the amounts did not match up to the amounts listed in the summary listing of invoices recorded by AIU. According to Staff, AIU claims only a partial amount on the invoice should be matched with the summary listing in the absence of any indication on the summary listing or on the invoice. Staff says AIU offered the explanation on Ameren Ex. 19.12 that the project manager made the determination of which charges on each invoice should be attributed to specific projects. Staff asserts, however, that Mr. Stafford concedes that the invoices contained no indication of the project manager's direction regarding specific invoices.

Staff indicates that Dr. Batchner asserts that where invoice amounts differ from the amounts shown on the summary listing of invoices, a partial amount should be allowed. In Staff's view, the suggestion that partial invoice amounts should be allowed is without merit. Staff acknowledges there could be legitimate reasons for the differences. Staff argues, however, that the knowledge that legitimate reasons for the discrepancy may exist does not substitute for documentary evidence that reconciles and substantiates

why invoice amounts differ from the amounts actually recorded by AIU on its books. Staff contends that AIU can not offer any credible explanation for some of the differences.

According to Staff, Dr. Batchers assertion that some, if not all, of the differences would have been easily ascertainable by simply learning more about the business is also without merit. Staff claims this shows Dr. Batchers lack of knowledge about which party bears the burden of proof. Staff maintains that AIU has responsibility to provide adequate documentation to support the costs included in its rate filing. Staff says that while it has spent considerable time and effort to make sense of AIU's plant records, Staff has no obligation to further expend its limited resources to help AIU satisfy its burden of proof.

Staff says Dr. Batchers asserts that Staff should have worked harder to find a way to make the illegible copies of invoices AIU provided legible. This assertion, Staff argues, indicates a fundamental misunderstanding about which party bears the burden of proof. According to Staff, AIU had every opportunity, before it filed the rate case, to ensure it had adequate, complete, and legible documentation for the costs it seeks to recover from ratepayers. After learning from Staff's direct testimony of the illegibility of some of its invoices, Staff says AIU once again had an opportunity to rectify the situation by providing legible invoices or alternative evidence that would adequately substantiate the costs in the illegible invoices. Instead, Staff claims AIU complained that Staff should have printed the illegible invoices on a different printer and played with various printer settings until it could read the invoice. Staff argues that if AIU's criticism were accepted then there would be no incentive for any utility to submit legible copies of any document to support costs it seeks to recover from ratepayers. Staff says reviewing and analyzing documentation of this magnitude is challenging enough without having to add what should be AIU's obligation: producing legible documentation of its costs.

Citing the Commission's decision in Docket No. 01-0701, Staff argues that it should not be ratepayers' responsibility to pay for late payment charges. Staff also refutes AIU's suggestion that Use Taxes and Purchasing Rate/Fixed Charge explain discrepancies in various invoices. In the latter case, Staff maintains that AIU failed to adequately explain the magnitude of such charges and when such charges are applied.

According to Staff, Dr. Batchers complained that Ms. Everson's review of invoices used a zero tolerance approach even though she was dealing with mergers and retired systems for storing the imaged invoices. According to Staff, a zero tolerance approach is reasonable, logical, and accepted in Illinois for reviewing plant records that a public utility has an obligation to retain, and for which AIU has the burden of proof to provide when it is requesting related plant costs be included in the determination of rates.

Staff says AIU criticized Ms. Everson for disallowing costs that are not supported by invoices as some are not retrievable from retired systems, indicating that alternative evidence should have been accepted, or if not extensive, that such missing items

should have simply been ignored in Staff's calculation of its disallowance. Staff maintains that the Commission's rules for record retention do not include any exemption for records simply because a utility chooses to retire a system, thus making retrieval more difficult or impossible. Staff restates that AIU and its predecessor companies all were subject to the record retention rules; so it is not valid that some allowance should be made for old or difficult to retrieve records.

Staff argues that since the summary listings were taken from AIU's general ledger, the general ledger is not a supporting source document for amounts that are drawn from the general ledger. In addition, Staff contends that continuing property records and retirement property unit records do not substitute for source documents, nor do they substantiate the cost of plant additions. According to Staff, the information generated through the queries to the general ledger systems was used to compile the list of invoices and voucher numbers. Staff adds that the underlying general ledger queries would simply be a repetition of the process that generated the list of invoices in the first place; it would not provide any additional support for the legitimacy of the costs.

Staff says the premise of AIU's position is that an invoice can be supported by the accounting records. Staff asserts that the source document for the accounting records is the invoice, not the other way around. AIU witness Nelson claims that the electronic transactions recorded on its general ledger can be relied upon to substantiate its costs as they can be independently verified through one of three different ways: 1) the accounts payable system, 2) the contractor system, and 3) the vendor's verifications. Staff notes that Mr. Nelson also testified that data from both the accounts payable system and the contractor system are fed into the general ledger's accounting system.

It is unclear to Staff how reports generated from either the accounts payable system or the contractor system would independently substantiate the costs recorded in the general ledger. Staff claims this reasoning is circular because there is no independent verification of the costs. As to the vendor's verifications, Staff says many vendors did not supply invoices with their affidavits that corroborate the costs in the general ledger. In addition, Staff states that Mr. Nelson testifies that AIU provided the information to the vendor regarding the costs the vendor verified. Staff adds that Mr. Nelson does not indicate how such vendors could have verified those costs over relatively long periods of time, some occurring as far back as 2003. Staff says Mr. Nelson is clear that using the data it has in its general ledger, accounts payable system, and contractor system, AIU prepared the information in the vendors' affidavits which it then had the vendors' sign. Staff believes this is circular reasoning and does not substantiate the costs in the general ledger.

Staff expresses concern about Ameren Ex. 19.12 in that AIU has not retained some of the invoices and has to rely on its vendors to provide invoices, many of which Staff says do not match to the amounts recorded to the general ledger and continuing property records. Staff indicates that AIU was not separately able to confirm from a vendor supplied invoice the reason for the difference, or whether the additional invoice

amount was either discounted for payment, or instead charged to another AmerenCILCO project. Based in part on this, Staff questions whether any of the invoices obtained in this manner can be relied upon to provide support for AIU's plant additions. Staff says the Commission can have no confidence that any such invoices are related to the amounts AIU claimed on its summary listings. Staff recommends disallowing these project totals from the determination of AIU's plant balances.

Staff indicates that in surrebuttal testimony, Mr. Stafford states that in response to Staff's concern regarding vendor-supplied invoices, AIU removed the costs associated with the vendor-supplied invoices that are being relied upon as support for project costs. Staff says it is unclear whether Mr. Stafford intends to mean that AIU has removed the costs associated with all vendor-supplied invoices that were provided to support project costs, or just ones that were disallowed by Staff. Staff claims it is nearly impossible without a line by line review of each item in the original summary sheets to determine if the claim that Mr. Stafford makes regarding the vendor-supplied invoices applies to all vendor-supplied invoices, or just the ones disallowed in Ms. Everson's calculation.

AIU witness Livasy provided rebuttal testimony that described the process that IP used for its electronic fund transfers (-EFTs"). IP's EFTs contain specific information that Mr. Livasy says was compiled or that existed such as work order numbers, invoice numbers, invoice dates, and vendor numbers to identify contractors. Staff complains that the testimony fails to provide any supporting documentation other than the results of queries on the same system that produced the amounts being tested.

Mr. Stafford claims that Ameren Ex. 19.13 provides support for the EFTs on IP projects. Staff says Ex. 19.13 is a spreadsheet with information on work order numbers, invoice numbers, invoice dates, general ledger amounts, vendor numbers and names, batch numbers, approvals, and the paying entity. The problem with this listing, Staff argues, is that this information came from the general ledger itself, not from an independent source that could corroborate its veracity. Staff says no invoices or contracts or any other evidence that the transfers were reviewed or approved were provided. Staff contends that an internally-generated document such as Ameren Ex. 19.13 which was produced from the same general ledger as the amounts in the general ledger in question only provides support that entries were made, and that funds were transferred from the AIU utility. In Staff's view, Ex. 19.13 does not provide support for the validity of the cost amount, or the applicability of the amount to a specific project, since no vendor invoices are provided. In other words, Staff does not believe the general ledger can substitute for independent third party evidence. According to Staff, there is no audit trail for the electronic transactions or presumably AIU would have provided it with its rebuttal testimony instead of relying on descriptions of the process.

Staff says that in response to Staff Data Request MHE 14.03, which asked AIU to produce the invoices to support its plant additions paid for by EFTs, AIU objected and stated that it was unable to immediately obtain that information. Staff indicates that AIU also stated that vendor payments are based on documented internal processes that

provide appropriate controls and authorizations for payment, satisfying vendors, auditors, taxing bodies and regulators including the Commission. Staff asserts that nothing was provided to document those alleged appropriate controls and authorizations. Staff says AIU could produce no Commission order to support its contention that this process had been approved by the Commission and could produce no written communication from the Commission's Accounting Department Manager that indicated approval of the electronic process.

Staff says much of AIU's surrebuttal testimony is essentially supplemental data that was requested by Staff in the MHE 3 series of data requests. Staff claims it is not in a position to know what is the universe of supporting documents for AIU's requested plant additions. Assuming Staff even knows the universe of such documentation, which Staff says it does not, Staff claims the magnitude of the information that needs to be sifted through to uncover problems, such as missing invoices or invoices with discrepancies, takes a significant amount of time. Staff claims it is not in a position to know how many plant assets are involved, thus, Staff can not know how many invoices Staff is supposed to get in support of such assets and related costs. Staff adds that thousands of line items reflecting plant additions and related costs are involved.

According to Staff, this complicated situation is further exacerbated by the fact that many data request responses were supplemented by AIU, and at times, supplemental responses were replaced by corrected supplemental responses. At the same time, Staff says key AIU rebuttal testimony and exhibits were revised after they were filed. In other words, Staff says it has had to contend with a moving target.

Staff asserts that at each point it received responses or supplemental data to prior data responses or to prior AIU testimony, Staff had no basis at those points in time to doubt the completeness of the responses and pursue additional responses from AIU through other means of discovery, such as a motion to compel. Staff believes it is only upon hindsight that one can see that AIU was not forthcoming in its provision of information necessary to adequately support its requested plant additions.

On July 1, 2008, Staff indicates it conducted cross-examination of the AIU witnesses. The purpose of the cross-examination, Staff claims, was not to provide an analysis of the information, but rather to illustrate how such an analysis should be conducted, the difficulty of the analysis, and how much time it would consume. Staff asserts that AIU has consistently provided faulty support for its costs in this proceeding.

Staff recommends that the adjustment proposed in Staff rebuttal testimony be adopted unless the decision maker conducts an analysis of the information provided in AIU's surrebuttal testimony. Staff asserts the analysis of this information would be time consuming and meticulous. In order to determine whether costs submitted with the surrebuttal testimony are supported, Staff says one would begin by comparing Ameren Ex. 43.6, Schedules 1-6 with Ameren Ex. 19.12, Schedules 1-6, to determine for each line item whether Ex. 43.6 contains better information than what was provided in Ex. 19.12. If new information is provided for a given line item, then, Staff says, Ex. 43.6,

Schedules 7 and 8 must be reviewed to locate the new support provided. If the support is located, then Staff states that Ex. 19.12, Schedules 8 through 13 must be reviewed to confirm that the information has not already been provided. Similarly, Staff claims that AIU's production in response to the MHE 3 series (Staff Cross Stafford Group Ex. 5) must be reviewed to determine that the information was not provided in that production. Staff indicates the documents within these exhibits are organized by utility, utility type, and Project Number. In addition, Staff says it must be confirmed that the cost was not previously allowed in Staff's review. If an invoice has been provided with Ameren Ex. 43.6, which has not been previously provided nor accepted by Staff, then Staff says the invoice should be reviewed to determine whether the amount is now supported. Staff asserts that since the information provided in Ameren Ex. 43.6, Schedules 1-8 contains no identification of which line items are new or previously provided, review of this information is difficult and extremely time-consuming.

Staff says the information provided in Mr. Nelson's surrebuttal are affidavits of vendors provided in lieu of actual or electronic invoices to support some of AmerenIP's EFTs. In addition to the concerns discussed above, the lack of specificity in the wording of the affidavit leads Staff to have concerns regarding the accuracy and reliability of these affidavits. According to Staff, these affidavits essentially constitute hearsay and can not be relied upon by the Commission as adequate support of AmerenIP's EFTs for which it could not locate supporting invoices.

In its Reply Brief, Staff says that AIU protests that Staff did not provide AIU with a listing of each and every invoice that Staff disallowed and contends that this shortcoming limited the ability of AIU to refute Ms. Everson's analysis. Staff believes AIU's argument is unfounded. Staff argues that AIU has sufficient information to determine which specific invoices were disallowed by Staff. Staff says the argument seems to be that Staff should have provided AIU with a detailed listing of each individual amount disallowed rather than the listing of amounts that Staff allowed. According to Staff, AIU's allegation that it is prejudiced by the presentation of Staff's adjustment in its work papers does not bear scrutiny. Staff claims AIU was capable of looking through the Summary Listings, identifying which invoices were disallowed, and then checking to see if they were duplicates, bills to the wrong company, etc.

In Staff's view, the complaint about Staff's work papers must be considered in context; the Summary Lists and the format which Ms. Everson used to identify her findings came directly from AIU. Staff claims there is no difference between using a slash to indicate Staff identified an invoice on a Summary Listing than AIU using a check to indicate the invoice had been provided. Staff avers that AIU's argument, that the very format that it found to be acceptable when making its production was unacceptable when used by Staff, is unpersuasive. Staff says its proposed disallowance was of a percentage of unsupported plant costs; it is not a disallowance of specific invoices or specific unsupported plant costs.

Staff states that while AIU did provide voluminous information throughout the case, it was provided without any roadmap until rebuttal. Staff complains that each new

production was provided with nothing to distinguish between new and old information. According to Staff, AIU seemingly equates the quantity of its documentation with quality. According to Staff, the explanations provided in Ameren Ex. 19.12 should have been the starting point provided to Staff for the analysis, but, the descriptions and the road map were provided for the first time in AIU's rebuttal.

Staff claims that AIU's Initial Brief fails to recognize that Staff modified its plant adjustment to eliminate any double-counting of Ms. Everson's adjustment for plant additions since the last rate case and Mr. Rockrohr's adjustments for plant held for future use and security installations. According to Staff, AIU cites Mr. Stafford's rebuttal testimony for this proposition and ignores Staff's rebuttal testimony where Ms. Everson indicates that she made changes to eliminate any double counting or double adjusting of plant additions prior to 2005. Staff says this modification is incorporated into Staff's rebuttal schedules and AIU's assertion regarding double counting is erroneous.

In its Initial Brief, Staff objects to AIU's practice of capitalizing the cost of employee meals. Staff says AIU could not cite a specific provision in the USOA that supports such a practice.

Staff recommends that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities with a copy of the report to be provided to the Manager of the Accounting Department of the Commission by June 30, of each year with the 2007 report to be submitted by December 30, 2008. Staff says the work papers of such audits should be made available and provided to Staff upon request. Staff asserts that requiring AIU to conduct its own internal audit will provide an opportunity for AIU to improve its record keeping skills. The annual reports submitted to the Commission, Staff avers, will provide some assurance to the Commission that AIU is taking steps during the time period between rate cases to improve its plant records. An improvement in record retention, Staff claims, should decrease the contentiousness of plant additions in the next rate case. Staff indicates that AIU witness Steinke stated that AIU has no objection to Staff's recommendation for an annual internal audit.

c. CUB's Position

According to CUB, AIU fails to provide sufficient cost justification to support the cost of plant additions since the last rate case, and therefore these costs should be disallowed. Some of the specific deficiencies include: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that do not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. CUB states that AIU presents Schedules 2.03E and 2.03G asking the Commission to reduce each utility's rate base, but AIU does not provide supporting documentation to allow adjustments to reduce each utility's rate base by the percentage of additions that have occurred since the last rate case and therefore should be disallowed.

d. Commission Conclusion

Because it believes that the costs associated with certain plant additions made since the last rate case have not been adequately documented, Staff recommends that such costs should be excluded from rate base. With very limited exception, AIU disagrees with Staff's position, arguing that it has adequately documented the costs associated with most plant investments. Staff has additional recommendations including that the costs excluded from rate base should be permanently written off and the assessment of fines for AIU's failure to maintain its books and records in the manner required by Commission rules. For the most part, AIU objects to Staff's additional recommendations.

As discussed extensively above, in evaluating AIU's capital investments since the last rate cases, Staff reviewed a sample of projects with total costs exceeding \$500,000 for each of the three utilities. Staff concluded that a portion of the costs associated with certain projects were inadequately supported. To develop its proposed adjustments to rate base, Staff applied the percentage of what it considered an inadequately documented amount of plant investment incurred by each utility since its last respective rate case.

As an initial matter, AIU objects to Staff's proposal to apply the percentage developed from projects with costs exceeding \$500,000 to the entire universe of plant additions since the last rate case, including those with costs below \$500,000. AIU argues that at most, Staff's proposed percentage disallowances should be applied only to those projects with costs exceeding \$500,000. Staff believes its assumption that the documentation for larger cost projects would be superior to the documentation for lower cost projects, and justifies the application of its percentage disallowances to both sizes of projects.

Having reviewed the arguments of the parties, the Commission finds that the record does not support Staff's proposal to apply the proposed percentage of disallowed plant costs to projects with costs less than \$500,000 since the last rate case. There is no objection to applying a percentage of disallowed costs to the universe of projects with costs greater than \$500,000 (from which the sample was derived), and the Commission finds that proposal reasonable. The preponderance of evidence, specifically that regarding sampling methodology, does not support applying a percentage of disallowed costs to projects with costs less than \$500,000. The assumption underlying this portion of the proposed adjustment is not adequately supported by the record.

In its Brief on Exceptions, Staff claims there is an inconsistency in the Proposed Order asserting that it rejects a portion of Staff's proposed adjustment to plant additions because Staff used a judgmental based sample rather than a statistical based sample, but did not reject AIU's judgmental based sample as support for AMS costs. The Commission understands Staff's view but believes its concern is misplaced and

oversimplifies the situation in which the Commission finds itself. With respect to both of these issues, as is typically the case, the record is not optimal but the Commission must make the best or reasonable decision based upon the record. With regard to plant additions, the Commission believes it is reasonable to apply Staff's proposed disallowance percentage to projects with costs greater than \$500,000 but not to projects with costs less than \$500,000. With respect to AMS costs, which are discussed more fully below, the Commission's only alternative to accepting AIU's sampling approach is to accept Staff's proposed allocation factor for AMS costs, which the Commission finds wholly unacceptable. Additionally, the Commission notes that in addition to the study of specific AMS costs performed by Concentric, it also performed several benchmarking studies that also provided important support for AIU's assertion that AMS costs allocated to AIU are reasonable. Thus, the Commission's decisions on these two issues must be viewed in the context of the available alternatives as well as the entire record related to each issue.

In its Brief on Exceptions, AIU identifies what it calls calculation errors and clarifications in the appendices to the Proposed Order. Among them is an assertion that the Proposed Order removes from rate base certain plant costs twice. AIU claims that because the starting point for removing plant from rate base in the Proposed Order is its rebuttal position, which already removes from rate base certain plant costs in agreement with Staff, AIU explains that acceptance of Staff's position would remove some of the plant costs twice. In its Brief in Reply to Exceptions, Staff suggests that the adjustment in the Proposed Order is correct and recommends rejecting the proposed change contained in AIU's Brief on Exceptions.

The Commission has reviewed the record and it appears that AIU is correct. Specifically, the Proposed Order applies Staff's proposed disallowance percentages to all AIU projects with costs in excess of \$500,000. As AIU suggests, however, the appendices attached to the Proposed Order begin with AIU's rebuttal position. AIU's rebuttal testimony acknowledges that certain plant costs can not be supported; therefore, AIU removed such plant costs from the plant costs it sought to include in rate base in direct testimony. (See Ameren Ex. 19.12 Revised and Ameren Ex. 36.1) Thus, by applying Staff's proposed adjustment percentage, developed in its direct testimony, to all projects with costs exceeding \$500,000, the Proposed Order excludes certain plant costs from rate base twice. The Commission finds that in order to avoid removing certain costs from rate base twice, it is necessary to correct the Proposed Order and this correction is reflected in the appendices attached hereto.

Staff proposes that certain costs associated with EFTs by AmerenIP be excluded from rate base because there is inadequate documentary support. AIU argues, among other things, that Staff has not previously proposed similar adjustments, that it thoroughly explained how the EFT process works, and that such costs tie into the accounts payable system and other AIU records.

As an initial matter, the Commission has no objection to AIU, or any other utility, making payments electronically or maintaining records in an electronic format. When

questioned by Staff or an intervenor in a rate proceeding, however, AIU must be able to document the underlying expenditure. As part of its support for EFTs, AIU provided third party or vendor copies of invoices along with affidavits of the vendors. With regard to this type of evidence, Staff recommends that the Commission treat this information as hearsay and give it no weight when deciding which costs should be included in rate base. The Commission has reviewed the disputed information and finds that it should be given little weight. The documents provided could be accurate representations or copies of invoices; however, it is not clear that is the case. The manner in which AIU solicited its vendors suggests to the Commission that vendors in all likelihood felt pressured to respond in a manner that AIU would deem favorable. The Commission would expect those vendors to want to please AIU so that they could maintain a business relationship. Of course, since the individuals who signed the affidavits were not present, it is impossible to know this or anything else about the veracity of the documents provided by the vendors.

With regard to AIU's assertion that the EFTs are supported by the fact that they match other AIU records, the Commission does not find this argument particularly compelling. As Staff suggests, simply because all of AIU's internal numbers match does not dispel the possibility that AIU's numbers are wrong. An underlying invoice would provide the necessary verification supporting AIU's internal records. Absent such documentation, it is impossible to discount that an improper EFT or an EFT for the wrong amount was initiated, processed, and completed.

Even putting these problems aside, the Commission is concerned that AIU expects the administrative law judges and the Commissioners to review individual invoices and determine whether such invoices are supportive of costs that Staff claims should be disallowed. This is tied directly to the remaining disputed amounts between AIU and Staff; those amounts AIU claims are adequately supported by the invoices provided along with AIU's surrebuttal. In its Reply Brief, AIU states that the Commission can not ignore this evidence and suggests that reviewing it would not be as time consuming and meticulous as Staff suggests. Having undertaken that effort, the Commission disagrees with AIU. The amount of information attached to AIU's surrebuttal testimony is quite voluminous. The more important problem, however, is that there is no context in which the information can be evaluated by the decision maker. In addition to the vendor provided invoices discussed immediately above, there are clearly other invoices attached to AIU's surrebuttal testimony. It is impossible, however, for the decision maker to determine if these invoices correspond to the specific disallowances proposed by Staff. The decision maker has no idea if an invoice for contract labor or any other specific cost corresponds to the specific costs Staff testifies were not previously provided, whether an invoice is duplicative of a previously provided invoice, or for that matter, whether an invoice is totally unrelated to a contested issue. In summary, while AIU provided additional information along with its surrebuttal testimony, the Commission is unable to determine that this information supports the costs that were previously unsupported. Accordingly, the Commission accepts Staff's adjustment on this issue.

Staff also recommends that AIU be required to permanently write-off any disallowance ordered in this proceeding. AIU opposes this proposal, arguing among other things, that it is too harsh. The Commission rejects the proposal to require a permanent write-off. The argument that AIU will not likely be able to provide superior documentation of costs in future rate cases, while superficially appealing, must be rejected. First, AIU argues that it already provided adequate documentation supporting its expenditures along with its surrebuttal testimony. While the Commission has been unable to determine that that is true in this proceeding, it would be unfair to require AIU to permanently write-off investment for which adequate documentation may simply have been provided too late in this proceeding. Second, given the incentive AIU should have to have costs included in rate base, it is possible it would expend sufficient effort between the conclusion of this case and the beginning of its next rate case to uncover adequate documentation of costs disallowed here. To properly balance the interests of ratepayers and shareholders, the Commission rejects Staff recommendation to order a permanent write-off.

Staff argues that AIU is in violation of the Commission's rules regarding records retention and that the Commission should therefore fine AIU. AIU acknowledges some record keeping problems but, nevertheless insists it is not in violation of the Commission's rules and objects to the proposal for a fine. In the context of this rate proceeding, the Commission declines to be further drawn into this dispute between Staff and AIU and rejects Staff's recommendation at this time. Other avenues and forums outside a contested rate case are available to Staff if it wishes to pursue this issue further. The Commission simply reminds AIU that it is expected to comply with all Commission rules.

Staff's recommendation that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities and provide a copy of the report to the Manager of the Accounting Department of the Commission by June 30 of each year, with the 2007 report to be submitted by December 30, 2008, is accepted. The work papers of such audits should be made available and provided to Staff upon request. Finally, any suggestion that ratepayers should be burdened with undocumented costs is not well taken. If costs can not be documented, they will not be reflected in rates, regardless of ownership changes or anything else.

As for Staff's late arising concern regarding the capitalization of employee meals, the record of this proceeding contains insufficient information to make an informed decision and insufficient data to make an adjustment if the Commission decided one were warranted. In any event, the Commission urges AIU and Staff to consider whether it is appropriate to include in rate base the capitalized cost of employee meals. For AIU, this is something it may wish to consider investigating immediately and, perhaps discussing with Staff, in an attempt to avoid an unnecessarily contested issue in its next rate case.

2. Plant Additions Disallowed in the Last Rate Case

a. Staff's Position

Staff witness Everson proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), and which she says AIU was still unable to provide supporting documentation. Staff reports that in rebuttal testimony, AIU witness Stafford agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Mr. Stafford recalculates Staff's proposed disallowance presented on Staff Exhibit 2.0R, Schedule 2.07 to reflect the portion of such additions that AIU concedes are unsupported, but reduces the proposed disallowances to reflect additional supporting documentation that AIU provided. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff claims the amounts on some of the invoices provided do not match with the amount of the asset listing. According to Staff, AIU has not provided the specific reasons that explain why a particular invoice amount does not agree with the asset listing. Staff says it still can not verify that the costs of plant additions that were put into service at least four years ago that the Commission disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base.

According to Staff, Mr. Stafford complains that Ms. Everson does not provide insight into which submitted invoices were accepted or rejected. Mr. Stafford claims that Staff does not appear to have conducted any review of the additional evidence AIU submitted. Staff says it had already reviewed the evidence presented in the previous rate proceedings and had also reviewed the evidence presented in the preparation of direct testimony. Staff claims that AIU admits that it did not have appropriate documentation for all of the contested plant additions and offers a multitude of reasons why a difference could exist. Staff says AIU does not identify the reason for each of the differences. Staff claims it investigated those same general reasons that AIU provided for the plant additions since the last rate case and found extensive follow-up and analysis was required. Staff submits that it should not have to work to prove that documentation does not exist. In Staff's view, if documentation exists, then AIU should provide it. Staff submits that if AIU does not provide documentation, then the additions should be disallowed. Staff states that these plant additions have been in service for over four years and AIU has been working on this case since January/February of 2007. According to Staff, the Commission should find that the burden rests with AIU as required by Section 9-201(c) of the Act.

In its Reply Brief, Staff insists that Ms. Everson reviewed only a sampling of the information and indicated that AIU had attempted to rebut this adjustment with reasons similar to those it used to rebut the disallowance of a percentage of plant additions since the last rate case. Staff states that the new information provided reinforces its concerns about AIU's inability to support plant additions. Staff says AIU's responses to Staff's inquiries about the rebuttal information reinforced instead of quelled Staff's concerns.

Staff asserts that AIU's responses regarding the deficiencies either retracted previous explanations or offered vague and non-specific information which cast doubt on the integrity of all of the explanations offered to the extent that Staff could not accept the explanations.

b. CUB's Position

In its Initial Brief, CUB supports Staff's proposed adjustments to rate base.

c. AIU's Position

AIU alleges that as with her adjustment for additions since the last rate case, Ms. Everson has not identified which specific invoices are at issue. AIU asserts that although it asked to be told which of Staff's two reasons for rejecting an invoice applied to each rejected invoice, Staff did not provide sufficient information to enable AIU to respond to Staff's proposed disallowance. AIU complains that it was necessary to conduct an analysis of the three projects for both AmerenCILCO and AmerenIP where Staff does not fully accept all additional supporting documentation.

According to AIU, it appears the primary reason Staff deemed an amount to be unsupported for AmerenCILCO is that taxes were paid for an invoice amount. According to AIU, this is not a valid reason to exclude an amount as unsupported. AIU says if AmerenCILCO was exempt from tax it would be a valid reason, but AmerenCILCO does have to pay tax where applicable. A review of two of the amounts in question, AIU states, indicates the amount deemed to be unsupported is exactly equal to 6.25% of the accepted amount for the invoice in question, which corresponds to the tax rate in effect at the time of said purchase.

With regard to AmerenIP, AIU claims that the primary reasons Staff deemed an amount to be unsupported are that two or more invoices are split between projects, or that project and/or work order numbers do not directly correspond to the project in question. AIU argues the fact that two or more invoices are split between projects is not a valid reason to exclude an amount as unsupported. According to AIU, if work is performed by a supplier for more than one project, then it is appropriate that such amounts should be accounted for separately. AIU alleges that in each of these examples, the supervisory personnel that approved said invoice or invoices determined that such costs should be split, with only a portion assigned to the project in question. AIU asserts that to handle this situation any differently would be incorrect, and is no reason to disallow a cost for recovery.

AIU argues that although Ms. Everson continues to recommend disallowance of plant additions disallowed in the last rate case in her rebuttal testimony, she does not challenge or respond to the positions or arguments Mr. Stafford makes in his rebuttal testimony. AIU alleges that her proposed adjustments for previously disallowed additions do not consider additional supporting documentation provided by AIU in

rebuttal. AIU claims Staff has provided no meaningful support for these proposed disallowances.

Ms. Everson, AIU says, claims that AIU's rebuttal on this issue is similar to that regarding plant additions since the last rate case. AIU asserts that its rebuttal on this issue is quite different from its rebuttal regarding plant additions since the last rate case. AIU states that for the 20 projects identified as unsupported in Staff Ex. 14.0, Schedule 14.07, AIU provides additional evidence in rebuttal supporting a portion of the proposed disallowed dollars for 6 of the 20 projects. For the remaining projects and dollars, AIU says it reflects an adjustment to reduce plant additions included in rate base in Mr. Stafford's rebuttal testimony. AIU claims 18 invoices support dollars at issue in six projects. This additional documentation, AIU argues, should have confirmed for Staff that neither of Staff's previously stated reasons for disallowance was valid for the majority of the costs. According to AIU, in the amounts cited, either the amount at issue was fully explained and reconciled, or neither reason given by Staff for the disallowance applied to the invoice at issue.

In its Reply Brief, AIU agrees that some of the previously disallowed additions remain unsupported. AIU says it is not seeking rate base recovery for those items; however, it is seeking recovery for additions that it claims are now supported. AIU asserts it has supported \$1,019,753 in plant additions that were disallowed in the last rate case and Staff provides no specific basis why this evidence is insufficient. Because Staff's adjustment is calculated as a percentage of total plant additions selected for review, AIU believes Staff's proposed adjustment should therefore be reduced from \$39,554,000 to \$22,991,000.

d. Commission Conclusion

Staff proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding and for which it says AIU was unable to provide supporting documentation in this proceeding. Staff reports that in rebuttal testimony, AIU agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff says it can not verify that certain costs disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base. According to Staff, the costs were not supported either because the invoices did not correspond with the listing of invoices provided or because the amounts on the invoices did not correspond to the amounts on the listing.

The Commission has reviewed the testimony as well as the arguments regarding plant investment that was excluded from rate base in the previous rate case. Despite AIU's assertion that it has adequately documented these investments, it is not clear to the Commission that is the case. As the Commission understands it, Ameren Ex. 19.6, Schedules 4 through 7, is intended to provide the documentation. The Commission, however, is unable to sort through the hundreds of pages of invoices and determine if

these documents establish the costs previously disallowed are adequately documented. While documents were provided, the Commission is unable to determine even if the invoices provided relate to the plant at issue. AIU is mistaken in its apparent assumption that it can provide a large number of invoices and the Commission will either assume the invoices support the costs at issue or can somehow effectively evaluate the invoices with no explanation. The Commission has no basis to make a determination that the invoices and documents support the costs at issue here. As a result, the Commission accepts Staff's proposal to exclude from rate base the disputed costs that were also disallowed in AIU's last rate case. Staff's proposed adjustments are quantified in each of the three Schedules 14.07-E attached to Staff Ex. 14.0.

3. Property Held for Future Use

a. AIU's Position

On April 3, 2006, AmerenCIPS purchased 31.28 acres, near the intersection of Seminary Road and Bockstruck Lane in North Alton, Illinois, for \$375,935. The land was purchased for AmerenCIPS to construct a new substation to be known as the North Alton Bulk Distribution Substation ("Substation"). AIU anticipates that the Substation will be in service by 2014. AIU indicates that the Substation is necessary to serve existing and future load in the northern and northwestern portions of Madison County.

AIU proposes that AmerenCIPS' investment in the land be included in rate base even though it is not currently being used to provide utility service. AIU argues that plant held for future use is a traditional component of rate base, which allows a utility to implement prudent, long-term planning strategies. Under Chicago v. Illinois Commerce Commission, 133 Ill. App. 3d 435, 441 (1st Dist. 1985), AIU understands that plant held for future use may be included in rate base if there is a plan to put it into service within 10 years of the test year. AIU also contends the Commission has also allowed plant held for future use to be included in rate base even beyond this 10-year period where the investment is shown to be "reasonable and the property should be retained; that a significant lead time was required between acquisition of a plant site and plant completion; and that long-range planning was necessary." (Id.)

Due to the long lead-times required for routing and obtaining a certificate of convenience and necessity from the Commission for a 138kV transmission to supply the Substation, as well as the lead times for engineering, design, material acquisition, and substation construction, AIU indicates that AmerenCIPS must begin planning for future load growth in the area now. AIU acknowledges that the parcel it purchased to accommodate its plans is most likely larger than what it will need for the Substation, but asserts that the seller wanted to sell the entire tract and not split the property. In AIU's view, it was necessary, prudent, and useful to ratepayers to purchase the entire parcel for purposes of building the Substation.

AIU urges the Commission to reject Staff's recommendation to disallow this \$375,935 investment from rate base. AIU avers that Staff witness Rockrohr does not

claim that the purchase of the property at issue was not prudent, but rather Staff takes the position that the land should be removed from rate base because it will not be used and useful until the Substation is constructed and placed in service. AIU argues that Mr. Rockrohr does not apply the appropriate standard when evaluating plant held for future use, and that to apply his standard would be the same thing as disallowing plant held for future use altogether.

AIU also disagrees with Mr. Rockrohr's claim that inclusion in rate base would be more appropriate in a future rate proceeding. AIU states further that he appears to take issue with the Commission's policy on plant held for future use itself. AIU submits that there is no evidence supporting Mr. Rockrohr's claim that a shorter standard time period for including plant held for future use in rate base is warranted where rate cases are filed more frequently.

b. Staff's Position

Staff recommends that the Commission disallow from rate base \$375,935 relating to a parcel of property on which AmerenCIPS intends to build a substation to be in service in 2014 or after. Mr. Rockrohr recommends that the Commission disallow the cost for this parcel for various reasons. He submits that AIU did not demonstrate that the property will ever actually be used for the Substation, nor did AIU provide sufficient evidence to show when the Substation will be in service, should it even be built. Mr. Rockrohr also contends that the evidence shows that even if the Substation is built, AmerenCIPS will utilize only a fraction of the parcel that it purchased. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS can adequately demonstrate that the subject parcel will be placed in service within ten years of the test year. He suggests that the Commission require AmerenCIPS to sell approximately 90% of the parcel (since AmerenCIPS will not need more than 10% for the Substation) and remove from rate base an amount equivalent to the proceeds from the sale. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS' actual use of the property is known.

c. Commission Conclusion

The issue here is whether AIU adequately demonstrated that its planned Substation will be built and in service on the parcel of land purchased within 10 years of the test year. AIU supplied the Commission with evidence showing that current and anticipated load growth in the area is driving the need for a new bulk supply substation. The Commission believes that AIU's intention to build the Substation is an example of prudent planning that benefits customers. The Commission also finds that AIU's investment in the property is reasonable and the evidence supports a finding that the timing of the acquisition is appropriate.

The Commission does not share Staff's concern that the Substation is not expected to occupy the entire parcel of land. As the Commission sees it, many factors

can influence a utility plan for locating and acquiring land for a substation. Such factors include the location and availability of property, as well as the ability to obtain property rights. Although the Commission believes it was reasonable for AIU to purchase the entire tract at issue here, the Commission directs AIU to use its best efforts to utilize or dispose of the remainder of the tract in a manner that best benefits customers. How AIU decides to deal with the remainder of the tract is an issue that can be revisited in future rate cases. The Commission concludes that AmerenCIPS' investment for the planned Substation should be included in rate base and Staff's proposed disallowance is rejected.

4. Security System Installations

a. AIU's Position

AIU argues that it is required, both as a matter of law and as a matter of prudent, safe, and reliable operations, to have effective security systems for its facilities as described in Section 4-101 of the Act. AIU submits that these provisions require it to have on-site safeguards to restrict physical access to critical infrastructure, and for the electric utilities to follow the most current security standards set forth by the North American Electric Reliability Corporation ("NERC"). According to AIU, the security systems that it installed are designed to meet these requirements. Because the security systems represent prudent investment in needed protection of its facilities, AIU argues that it is entitled to have the security investment included in rate base.

In support of its argument, AIU points out that electric transmission lines, substations, gas pipelines, storage fields and other facilities are considered critical energy infrastructure. AIU submits that securing such critical infrastructure is necessary not just to ensure that customers have adequate and reliable service, but also that interconnected facilities of other utilities throughout the region and the country are protected. AIU points out that Staff witness Rockrohr does not compare AIU security systems or their costs to those of non-AIU utilities, nor did he conduct any outside research into, or review publications related to, security systems. AIU notes that Mr. Rockrohr agrees that protection of AIU's critical infrastructure from terrorist attack and criminal activity is necessary, and he further agrees that AIU's customers benefit from measures to protect AIU's facilities. AIU argues that the evidence in this case shows that its security systems are reasonable and necessary to protect its critical infrastructure and other facilities and personnel. AIU submits that Staff's lack of a meaningful comparison of other utilities to AIU demonstrates that Staff has no basis to recommend disallowance of security costs.

b. Staff's Position

Staff recommends that the Commission disallow \$178,173 from AmerenCILCO's proposed rate base, \$881,686 from AmerenCIPS' proposed rate base, and \$417,528 from AmerenIP's proposed rate base, which represents installation costs of state-of-the-art security systems at each utility's facilities. Staff contends that AIU demonstrated no

need for these security systems, considered no alternative systems, and did not even know the ongoing costs associated with utilizing them. Staff argues that the NERC guidelines do not state that each utility must, or even should, install card readers and closed circuit television cameras at all of its facilities. Instead, Staff notes that the NERC guidelines list types of security systems that a utility might consider when evaluating the adequacy of its existing security. In support of its proposal, Staff points out that even though AIU witness Mullenschlader claims the security systems were installed to satisfy the requirements of NERC guidelines, when asked if AmerenCIPS had experienced security issues at the three facilities associated with AmerenCIPS' expenditure of \$608,799, Mr. Mullenschlader stated that no specific data was available. After reviewing all the information that AIU provided about the security systems that were installed at facilities within the operating areas of AmerenCILCO, AmerenCIPS, and AmerenIP, Mr. Rockrohr remains unconvinced that the security system investments were prudent and used and useful in providing service to customers. He believes that these security system costs would more appropriately be paid for by the shareholders of each utility than by customers.

c. Commission Conclusion

The Commission agrees that securing AIU's infrastructure is necessary to ensure that customers have adequate and reliable service. The Commission also believes that AIU's security system costs are a prudent investment, that the security systems benefit customers, and that these systems are used and useful in providing service to customers. Contrary to Staff's suggestion, the need for maintaining the security of utility assets has increased dramatically and what may have been considered excessive or state of the art only a few years ago is now necessary and appropriate.

The Commission, however, is concerned that AIU considered no alternatives to the security system it installed. The Commission understands that AIU chose to use the same vendor that it has previously used; however, in the future AIU should undertake an investigation regarding both the need for and the cost of alternative security systems and be able to better document and justify decisions it makes regarding security investments.

5. Cash Working Capital

a. AIU's Position

In its direct case, AIU presented the results of a lead-lag study to quantify the CWC requirements of each of the gas and electric businesses of AIU. AIU states that CWC reflects the amount of funds required to finance the day-to-day operations of AIU. AIU relates that the two most commonly used methodologies by which to determine a company's CWC requirements are referred to as the "~~Net~~ Lag" and "~~Gross~~ Lag" methodologies. AIU adds that the CWC requirements for each of the utilities were calculated employing the Net Lag methodology. Ameren Ex. 3.5 shows the calculation of CWC requirements under the Net Lag methodology. If prepared properly, AIU claims

the two methodologies should produce identical results. Ameren Exs. 5.7, 5.8, and 5.9 set forth the calculation of AIU's CWC requirements under the Gross Lag methodology. AIU reports that both methodologies yielded the same results.

Staff witness Kahle has suggested six modifications to the CWC requirements proposed by AIU: (1) use of the Gross Lag methodology rather than the Net Lag methodology; (2) inclusion of pass-through taxes in the calculation of the revenue lag with zero lag days; (3) inclusion of capitalized payroll in the level of payroll expenses used to determine AIU's CWC requirements; (4) correction of the expense lead associated with Employee Benefits; (5) reflection of the impact of Transitional Funding Trust Notes ("TFTN") interest expense; and (6) reflection of Staff's proposed levels of operating expenses in the CWC analysis.

AIU agrees with Mr. Kahle's correction of the expense lead associated with Employee Benefits. AIU says the expense lead originally filed contained a cell reference error that needed to be updated to reflect the corrected expense lead days. AIU believes Mr. Kahle has accurately reflected the expense lead as 24.746 days. AIU indicates that adjusting the expense lead for Employee Benefits reduced AIU's CWC requirements by approximately \$9,000. AIU says it also accepts Mr. Kahle's treatment of interest expense on TFTN in the CWC analysis.

AIU does not take exception to Mr. Kahle's use of the Gross Lag methodology, if applied correctly. While it accepts the use of the Gross Lag methodology, AIU disagrees with Mr. Kahle's statement that the Net Lag methodology does not consider the amount of cash provided by ratepayers through base rates. AIU insists that the Net Lag methodology presumes that the operating expenses considered in the analysis are the same as the revenues available to pay such operating expenses; therefore, the Net Lag methodology inherently includes the consideration of revenues, but it does not reflect revenues on the exhibit. Staff, AIU claims, continues to have the misperception that only the Gross Lag methodology reflects revenues. AIU asserts that both methodologies reflect revenues but only the Gross Lag methodology actually shows the revenues on the exhibit.

AIU asserts that the revenues used by Mr. Kahle reflect the revenue requirement which Staff believes to be necessary to earn a fair return on AIU's assets and to pay its operating expenses. From this amount, under the Gross Lag methodology, AIU says the return on equity and all non-cash operating expenses are removed from the operating revenues. The residual revenues included in the CWC analyses under the Gross Lag methodology, AIU states, are the amount required to pay cash operating expenses.

AIU says the objective of the CWC analyses is to evaluate the timing differences between the receipt of revenues and payment of expenses. To accurately determine the CWC requirements, AIU insists that the revenues considered in the analyses must correspond to the expenses and vice versa. AIU asserts that the inclusion of expenses for which there is no corresponding revenue stream will produce results which do not

reflect the true CWC requirements of AIU. When employing the Gross Lag methodology, AIU says it is important to maintain a balance between the level of revenues and operating expenses considered in the analyses. AIU states that the level of revenues considered in the analyses should reflect only those funds which are available to pay actual cash operating expenses. AIU says a number of reductions are made from actual revenues to arrive at the amount which is truly available to pay actual operating expenses. Similarly, AIU claims the operating expenses considered in the CWC analyses should only include those operating expenses for which there is a corresponding revenue stream.

AIU claims that its application of the Gross Lag methodology maintains the balance between revenues and operating expenses because the revenues and operating expenses considered in the CWC analyses are equal. AIU asserts that the analyses set forth by Mr. Kahle, however, does not maintain the balance between revenues and operating expenses. According to AIU, Mr. Kahle inappropriately makes changes to the level of operating expenses (e.g., capitalized items) without a corresponding change to the revenue side of the equation. Under Mr. Kahle's approach, AIU claims the operating expenses have been artificially inflated thereby erroneously reducing AIU's CWC requirements.

AIU takes exception to Mr. Kahle's proposed treatment of pass-through taxes in calculating CWC requirements. Mr. Kahle proposes to include pass-through taxes in the CWC analyses, but to reflect a revenue lag associated with these taxes of zero days. AIU says Mr. Kahle assigns an expense lead of 42.79 days for the pass-through taxes. AIU claims the reduction of AIU's CWC requirements based upon Mr. Kahle's proposed adjustment to pass-through taxes is approximately \$7 million.

According to AIU, Mr. Kahle's proposed treatment of pass-through taxes should be rejected because it has no foundation in reality. AIU says the revenue lag consists of five components; (1) a service lag; (2) a billing lag; (3) a collections lag; (4) a payment processing lag; and (5) a bank float lag. Collectively, AIU claims these components add up to the 40.95 days of revenue lag utilized by both Staff and AIU for purposes of determining AIU's CWC requirements. AIU states that the expense lead consists of three components; (1) a service lead; (2) a payment lead; and (3) a bank float lead. The expense lead used by both Staff and AIU was determined to be 42.79 days.

In AIU's view, it is appropriate to include pass-through taxes in the CWC analyses because there is a slight timing difference between AIU's receipt of payment from customers and the remittance of the taxes to the proper taxing authority. By including the pass-through taxes in the CWC analyses, AIU claims it is reflecting the benefit of having access to the funds from the time of receipt to the time of remittance.

According to AIU, Mr. Kahle's position is based on the incorrect premise that AIU has access to the funds associated with the pass-through taxes for 42.79 days. AIU contends that it collect the funds associated with the pass-through taxes when the

customers pay their bills. AIU maintains that there is no separate source of funds provided by the customers associated with the pass-through taxes.

Mr. Kahle, AIU avers, appears to suggest that there is no service lag associated with the pass-through taxes. AIU says that while that may be a reasonable position, there can not be a service lead on the expense side of the CWC calculation if there is no service lag on the revenue side of the equation. AIU claims Mr. Kahle's rebuttal position acknowledges this fact. Despite this modification, AIU asserts that Mr. Kahle's position continues to be flawed because it fails to reflect the true timing of cash receipts versus cash outlays. Despite Mr. Kahle's assertion to the contrary, AIU insists it does not have access to the funds attributable to the pass-through taxes during those days and claims that Mr. Kahle has provided no evidence to the contrary.

AIU also disputes Staff's assertion that pass-through taxes are not revenue. According to AIU, pass-through taxes are included in both revenues and expenses in the test year, before pro forma adjustments. AIU argues that it has provided service to customers, giving rise to the cost associated with pass-through taxes, and have to collect such monies from customers. Without the provision of service, AIU says there are no pass-through taxes.

If the Commission were to determine that there was no service lag/lead associated with the pass-through taxes, AIU says a revenue lag of 25.74 days should be applied to the appropriate level of revenues attributable to pass-through taxes and an expense lead of 27.58 days (i.e., 42.79 minus 15.21 days) should be applied to the expense levels associated with pass-through taxes. AIU states that this change would result in no change to AIU's CWC requirements. AIU also claims that the Commission previously declined to adopt the position proposed by Mr. Kahle. (AIU Initial Brief at 79-80, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 22)

AIU also takes exception to Mr. Kahle's proposed inclusion of capitalized payroll expenditures in the operating expenses used to calculate the CWC requirements. AIU indicates that Mr. Kahle proposes to include capitalized payroll in the CWC analyses by adding the amount of capitalized payroll to the operating expenses without a corresponding revenue stream. According to AIU, the impact of Mr. Kahle's proposed inclusion of capitalized payroll in the CWC analyses is to reduce AIU's CWC requirements by approximately \$3 million.

Mr. Kahle, AIU states, tries to justify the use of this limited number of capitalized items in the calculation of the CWC requirements on the grounds that the Commission accepted a similar position in the last electric rate proceedings for AIU (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 36). AIU contends that Mr. Kahle, however, has provided no independent justification or rationale for the inclusion of the capitalized items in the CWC analyses, and, asserts that they should not be included at all.

AIU argues that Mr. Kahle has artificially created an imbalance by including in his analyses expenses for which there is no corresponding revenues, thereby resulting in a lower CWC requirement which is not indicative of the true CWC needs. AIU claims Mr. Kahle's inclusion of these capitalized costs is also inappropriate because his analyses represent only a partial view of capitalized expenditures. AIU claims it incurs significant levels of expenditures on an annual basis associated with capital programs and initiatives. AIU says Mr. Kahle's proposed treatment of capital expenditures does not reflect all of the capital expenditures and that he is selective in what items to include. Further, AIU asserts that Mr. Kahle has reflected an expenditure with significant dollars and relatively short expense lead time, artificially deflating the CWC requirements of AIU. In AIU's view, Staff's analyses reflect an incomplete view of capitalized expenditures and an artificially created imbalance between the revenues and operating expenses.

AIU says it has not included all of the capitalized expenditures in its CWC analyses. AIU claims its analyses reflect the actual cash operating expenses incurred during the test year. The capitalized amounts, AIU argues, are appropriately included in rate base and thus earn a return on such investments. AIU insists that it is inappropriate to include the capitalized expenditures in the CWC analyses. Regardless, AIU contends it would be inappropriate to include only a portion of the capitalized expenditures and only on one side of the revenue and expense equation. AIU maintains that the revenues which Mr. Kahle uses reflect the revenue requirement for the AIU. From those revenues, AIU says he appropriately subtracts non-cash expenses and return on equity. The residual revenues, AIU states, are those dollars which are available to pay cash operating expenses. AIU claims there are no incremental dollars in the analyses to account for the capitalized expenditures which Mr. Kahle proposes to include in the analyses. AIU concludes that Mr. Kahle has artificially created an imbalance between the levels of revenues and expenses considered in the analyses.

AIU is aware of only one solution that could remedy that imbalance: include in the CWC analyses a separate revenue stream relating to the amount of capitalized payroll. AIU says the revenue lag for this revenue stream would have to be the composite years over which AIU's assets are depreciated. AIU states that Mr. Adams, however, did not perform such a calculation because he does not agree with the inclusion of the capitalized expenditures in the CWC analyses. AIU, therefore, does not believe that an alternative to address Mr. Kahle's flawed recommendation is warranted.

Mr. Kahle believes it is appropriate to include the capitalized payroll in the CWC analyses because the test year is a historical test year and no portion of payroll after the effective date of the new rates is included in the rate base. AIU disagrees because the test year reflects a full twelve months of wages, reflected for known and measurable changes. AIU asserts that there is no need to reflect some level of payroll after the effective date of the new rates. AIU says Staff has not adjusted the expense level of wages to address this concern of Mr. Kahle's. AIU therefore concludes that there is no need to make such an adjustment for the CWC analyses.

AIU says it is true that it has not included capitalized payroll for the calendar year 2009 and claims it would be inappropriate to do so without a known and measurable capital adjustment with which the capitalized payroll is associated. According to AIU, Mr. Kahle's adjustment reaches beyond the 2006 test year to include 2009 capitalized payroll, which he assumes will be incurred at the 2006 historical level, and includes the presumed capitalized expenditure in an historical test year. AIU asserts that Staff has provided no evidence that the level of capitalized payroll in 2009 will be the same as it was in 2006. AIU says its level of capitalized payroll varies on an annual basis. Once the actual capitalized expenditures are incurred, AIU claims they will be reflected in AIU's rate base in the next rate proceeding. AIU insists that it would be inappropriate to include an unsubstantiated level of future capitalized payroll in these proceedings. AIU also disagrees with Staff that its proposal correctly reflects cash needs, since Staff has not provided a source of cash for the capitalized payroll cash outlay. If the Commission decides to include the capitalized expenditures, AIU maintains that a revenue stream must also be included in the CWC analyses.

AIU says that in rebuttal, Mr. Kahle argues that AIU witness Adams is wrong in asserting that a balance between revenue and expense level is required because the Commission's order in AIU's prior rate proceedings included adjustments to CWC which were based on analyses in which expenses were greater than revenues. AIU states that Mr. Kahle also argues that the inclusion of the capitalized portion of payroll expense in determining CWC requirements does not affect AIU's recovery of payroll costs.

According to AIU, Mr. Kahle's argument for his treatment of capitalized expenditures is based exclusively on the Commission's decision in AIU's last electric cases. AIU says it does not believe that a mistake should be repeated merely based upon past mistakes. AIU believes the appropriateness of the proposed adjustment should be evaluated based upon the merit of the arguments in the proceeding and not merely upon a prior Commission ruling. AIU maintains that Mr. Kahle's proposed adjustment is flawed, does not reflect the true CWC requirements of AIU, and should be rejected.

To the extent Commission precedent guides the Commission in this proceeding, AIU urges the Commission to focus on Docket Nos. 07-0241/0242 (Cons.). In that more recent proceeding, AIU says the Commission reversed its decision on this issue. AIU claims that Mr. Kahle dismisses that decision by claiming that the circumstances were different. In AIU's view, the circumstances in the two cases are not different; only the result was different and did not favor Staff's proposed adjustment.

Mr. Kahle has also proposed an adjustment to the CWC component of Rider PER - Purchased Electricity Recovery ("Rider PER"). AIU indicates that Mr. Kahle's calculation uses 23.94 expense lead days instead of the 18.15 days AIU proposes to use. AIU states that Mr. Kahle believes since AIU and Ameren Energy Marketing Company are affiliates, it is not reasonable to apply the shortened service period and advanced payment time to their transactions. AIU asserts that its current credit ranking has shortened the service period for purchased power to a half-month with payments

due on the first business day nine days following the end of the service period. AIU says Mr. Kahle does not contest the application of the shortened payment periods for non-affiliated companies, but proposes to disallow the shortened payment period for affiliated companies. Mr. Kahle contends that the shortened payment period does not apply to the affiliated companies because the funds for these purchases come from and end-up in the same pool of money.

Based upon Mr. Kahle's proposed adjustment, AIU says it appears that he believes that the dealings with affiliates should be handled differently than those with non-affiliated companies. Citing 83 Ill. Code 450, "Non-Discrimination in Affiliate Transactions for Electric Utilities" ("Part 450"), AIU claims the Commission's rules pertaining to transactions with affiliated marketing companies strictly forbid such unique treatment. AIU believes that providing payment terms which are different than those encountered between AIU and non-affiliated marketing companies would be contrary to the Commission's rules. AIU also argues that it and Ameren's marketing affiliates do not commingle funds as suggested by Mr. Kahle. AIU says each business operates as a stand-alone company and is responsible for its own financial transactions. AIU also claims that the source of the funds has no relevance on the timing of payment for transactions. The CWC component of Rider PER, AIU asserts, should reflect the actual timing of cash receipts and cash payments, not Mr. Kahle's assumed preferential treatment afforded to an affiliated marketing company.

AIU says that in rebuttal, Mr. Kahle argues that using the shortened service period for AIU's purchases from affiliates does not run afoul of Part 450 because it only prohibits preferential treatment, and his proposal does not provide preferential treatment. According to AIU, Mr. Kahle also argues that although AIU and Ameren Energy Marketing Company do not commingle funds, it is not logical that Ameren Energy Marketing Company would refuse to keep AIU as a customer if its payments were not advanced as allowed under the Supplier Forward Contracts.

According to AIU, the Commission has rules in place to protect against preferential treatment between affiliated companies. AIU claims Mr. Kahle is essentially proposing to bypass such safeguards. AIU asserts that Mr. Kahle makes an unsubstantiated assumption that the affiliated suppliers would even be willing to provide different payment terms for AIU. AIU contends that the non-affiliated providers could also choose to not seek advanced payments, but they did not. AIU believes it is unreasonable to assume that the affiliated providers would be more willing to waive the accelerated payments and assume additional risk without compensation. In AIU's view, these are the types of situations which the Commission's affiliate rules are intended to prevent. AIU concludes that Mr. Kahle's proposed adjustment to the CWC component of Rider PER should be rejected.

b. Staff's Position

Mr. Kahle proposes downward adjustments to the level of CWC to be included in rate base by the following amounts: \$645,000 for AmerenIP's gas operations,

\$1,563,000 for AmerenIP's electric operations, \$668,000 for AmerenCIPS' gas operations, \$1,060,000 for AmerenCIPS' electric operations, and \$72,000 for AmerenCILCO's electric. He proposes an increase of \$151,000 for AmerenCILCO's gas operations. To calculate his proposed CWC for AIU, Mr. Kahle proposes adjusting the lead days for Employee Benefits to 24.746 days due to an error in AIU's lead/lag workpapers related to Group Health Administration lead days. Staff indicates that AIU accepts Staff's adjustment for each of the utilities.

Mr. Kahle also proposes that the Gross Lag methodology be used in calculating CWC. AIU indicates that it is willing to accept the use of the Gross Lag methodology as long as the methodology is applied properly. Thus, Staff reports that the following CWC items are in dispute: capitalized payroll in CWC requirements; applying zero revenue lag days to pass-through taxes; and expense levels to which CWC factors are applied.

Mr. Kahle proposes to include total payroll in the CWC requirements, including the amounts capitalized as well as those charged directly to expense accounts in the CWC calculation, since all require cash. AIU argues that capitalized items are appropriately included in rate base, not in the CWC analyses. Staff contends, however, that capitalized payroll included in rate base does not include any payroll costs going forward. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding.

Staff asserts that processing and paying payroll is part of the AIU's day-to-day operations, that payroll to be paid in January 2009 is not in rate base in this proceeding and is outside the test year, and that AIU requires cash to meet its payroll in January of 2009. According to Staff, the circumstances in this proceeding are similar to the previous AIU rate case proceeding in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), in which the Commission found that the capitalized portion of payroll should be included in the CWC calculation. Staff believes that its proposal, which uses total base payroll in the CWC requirement calculation, correctly reflects cash needs of AIU and should be approved by the Commission rather than AIU's proposal which only considers payroll costs charged directly to salary and wages expense accounts.

In its Reply Brief, Staff claims AIU attempts to confuse the issue by implying that capitalized expenditures should not be included in the CWC requirement calculation because capitalized expenditures are included in rate base. Staff argues that expenditures, whether expensed or capitalized, are not, in themselves, recovered by adding the CWC requirement to rate base. Staff claims that only the financing of the expenditure is recovered by adding capitalized items to rate base. According to Staff, CWC is the amount of funds required from investors to finance the day-to-day operations of AIU. Adding CWC to rate base, Staff states, allows the investors to recover the time-value-of money associated with the cash outlay. Staff submits that including the capitalized portion of payroll expense in determining the CWC requirements only affects the amount of CWC requirement added to rate base for financing day-to-day operations of AIU, and does not affect the recovery of payroll

expense itself. Staff says AIU also advances an argument that revenues and expenses in the CWC requirement calculation must be equal. Staff contends this is not the case since the Commission has adopted CWC requirement calculations in which revenues and expenses are not equal. (Staff Reply Brief at 38-39, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Appendix A, B and C at 6; Docket Nos. 07-0241/07-0242 (Cons.), Appendix A at 10 and Appendix B at 9) Staff also claims that in previous AIU rate proceedings, AIU has filed CWC requirement calculations in which revenues and expenses are not equal for AmerenCIPS gas and AmerenUE.

Mr. Kahle proposes to apply revenue lag days of zero to pass-through taxes. According to Staff, there is no revenue lag associated with pass-through taxes since pass-through taxes are not revenue. Staff asserts that AIU provided no service and did nothing to earn pass-through taxes. Staff claims investors have provided no investment related to the collection of pass-through taxes other than for operation and maintenance expenses already included elsewhere in the CWC calculation. Pass-through taxes, Staff says, are added on to the ratepayers' bills and then remitted to the appropriate taxing body. Staff contends that including a revenue lag for pass-through taxes in the CWC calculation would increase AIU's CWC requirement, and thereby increase rate base, allowing investors to earn a return on ratepayer supplied funding.

Staff states that ratepayers provide pass-through taxes for a taxing body with AIU having the use of these funds until AIU remits the taxes to the appropriate taxing body. Energy Assistance Charges, Staff states, are paid monthly by AIU on the 20th day following the month. AIU has use of these ratepayer provided funds from the time they are collected until the 20th of the following month plus bank float time, according to Staff. Gross Receipt Taxes, Staff adds, are paid monthly by AIU in the month following the month for which they are due. Staff says AIU has use of these ratepayer provided funds from the time they are collected until they are paid in the following month. Staff concludes that its proposal to use zero days for revenue lag correctly reflects that AIU has no cash requirements necessary to collect and remit pass-through taxes.

Mr. Kahle also proposes an adjustment to the CWC component of Rider PER to use 23.94 expense lead days instead of the 18.15 days that AIU proposes to use. AIU claims that Staff's logic is flawed and that it is reasonable to apply a shortened service period and advanced payment time in the transactions between AIU and Ameren Energy Marketing Company. Staff asserts that while AIU is referring to the affiliates' payment terms, Staff is referring to the calculation of the CWC component of Rider PER. Staff argues that its calculation affects Rider PER but not the actual power purchases from affiliates. Staff contends that using a greater number of expense lead days for the CWC component of Rider PER, which causes AIU to have a lower CWC requirement for purchased power, is not preferential treatment of an affiliate.

c. The AG's and CUB's Position

In addition to the CWC requirements based on the lead-lag studies, CUB says AIU increased the electric rate bases for each utility by an additional CWC allowance to

reflect a material increase in accounts receivable being experienced by AIU since the 2006 test year. According to CUB, the additional CWC increases the AmerenCILCO electric rate base by \$3,478,000, the AmerenCIPS electric rate base by \$6,406,000, and the AmerenIP electric rate base by \$10,116,000. CUB says the increase applicable to each individual utility was calculated by allocating the total requested increase of \$20 million in accounts receivable among the three utilities based on the number of electric distribution customers of each of the utilities. The \$20 million total, CUB states, is based on an observed increase in the balance of accounts receivable in September 2007 over the level in prior years.

In CUB's view, there are several problems with the additional CWC increases proposed by AIU. CUB argues that AIU has not established that the observed increase in 2007 is permanent in nature. CUB also contends that an increase in accounts receivable by itself does not establish an increase in the CWC requirement. The CWC requirement, CUB says, is calculated as the cash needed to bridge the gap between the payment of expenses and the receipt of cash from customers to cover those expenses. To the extent that the increase in accounts receivable is the result of an increase in expenses, CUB claims the increase in receivables could well be matched by an increase in payables, resulting in no net increase to the CWC requirement. Based upon these concerns, AG/CUB witness Effron proposes that the additional CWC related to the increase in accounts receivable in 2007 be eliminated from AIU's electric rate bases.

d. Commission Conclusion

With regard to calculating CWC, the only remaining contested issues between Staff and AIU are whether capitalized payroll should be included in CWC requirements and whether it is appropriate to apply zero revenue lag days to pass-through taxes. The AG/CUB as well as Staff propose eliminating the additional CWC requirement associated with increased accounts receivable in 2007. In its rebuttal testimony, for purposes of the instant proceeding, AIU withdrew its proposal to increase CWC to reflect higher accounts receivable in 2007; thus, this issue is no longer contested. Finally, the Commission's review of AIU's and Staff's Briefs on Exceptions and their Briefs in Reply to Exceptions reveals that the Proposed Order failed to include a conclusion regarding whether the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU should be adjusted as Staff proposed. It appears the Proposed Order failed to reach a conclusion on this issue, in part, because Staff treated this as a contested rate base issue while AIU treated it as a resolved electric rate design/tariff issue. In any event, this issue will be addressed in this portion of the Order.

As the Commission understands it, Staff proposes to include capitalized payroll, as well as payroll expense, in the CWC calculation since Staff believes both types of payroll payments require cash. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding. Alternatively, AIU argues that capitalized items are appropriately included in rate base and not in the CWC analyses.

The Commission has reviewed the arguments of the parties as well as the previous decisions cited by the parties. Utilities acquire cash when ratepayers pay bills as well as through the issuance of debt and equity. The sources and uses of cash are comingled and can not be distinguished. The purpose of estimating a CWC requirement is to determine the level of funds required to meet a utility's day-to-day operations. By including CWC in rate base, the Commission allows a utility the opportunity to recover the cost of raising cash from its investors that is used in day to day operations. Capitalized costs, which are all paid with cash, are included in rate base so that a utility has an opportunity to recover the cost of financing that capital requirement item over time. In the Commission's view, if any capitalized cost, including capitalized payroll costs, were also reflected in the CWC balance, it would effectively be included in rate base twice. While it is true that cash is required to meet the requirements for payroll costs that are capitalized, the same is true for every other expense that is capitalized and the Commission can not understand the basis for singling out capitalized payroll costs. As a result, the Commission rejects Staff's proposed treatment of capitalized payroll costs when estimating the CWC requirement.

The Commission recognizes that Staff's proposed adjustment is consistent with the Order in the last AIU rate case; however, a review of that Order suggests AIU's failure to properly brief the issue in that case did little to help its position. Additionally, the Commission notes that the decision herein is consistent with the more recent decision in Docket Nos. 07-0241/07-0242 (Cons.), and believes the decision here is consistent with the record of this proceeding.

With respect to pass-through taxes, Staff proposes to apply zero revenue lag days arguing: that pass-through taxes are not revenue; that AIU provides no service and did nothing to earn pass-through taxes; and investors have provided no investment related to the collection of pass-through taxes. AIU believes pass-through taxes should be reflected in the CWC analysis due to the slight timing difference between AIU's receipt of payment and the remittance of tax revenue.

The Commission reviewed the arguments and, in the context of a CWC requirement, is unable to discern a meaningful difference between pass-through taxes and most other expenses. Customers pay their bills, including pass-through taxes, providing AIU with cash. AIU makes cash payments, including pass-through taxes, to those entities that have a rightful claim. Again, in the context of CWC requirement, pass-through taxes are no different than State or Federal income taxes or employee payroll expense. The Commission therefore concludes that Staff's proposed adjustment to the CWC requirement associated with pass-through taxes is inappropriate and is hereby rejected.

Staff proposes to adjust the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU, but not the expense lead days between unaffiliated suppliers and AIU. Under Staff's proposal, Ameren Energy Marketing Company would be treated differently than unaffiliated power

and energy providers. These transactions are governed by supply contracts previously approved by the Commission, and the Commission finds Staff's proposal is inconsistent with the intent that all power and energy providers are to be treated the same. Staff's argument that it is simply proposing an adjustment to lower the CWC requirement but not the actual power purchases from Ameren Energy Marketing Company misses the point. This proposal would effectively deny AIU the opportunity to recover costs associated with supply contracts AIU entered into under Commission oversight. Such a proposal is not reasonable and is therefore rejected.

6. Physical Losses and Performance Variations

This issue concerns Accounts 352.3, "Nonrecoverable natural gas," and 823, "Gas losses," of the USOA for Gas Utilities. Account 352.3 provides in relevant part:

A. This account shall include the cost of gas in underground reservoirs, including depleted gas or oil fields and other underground caverns or reservoirs used for the storage of gas which will not be recoverable.

Account 823 states in its entirety:

This Account shall include the amounts of inventory adjustments representing the cost of gas lost or unaccounted for in underground storage operations due to cumulative inaccuracies of gas measurements or other causes. (See Paragraph G of Account 117, Gas stored underground – Noncurrent.) If however, any adjustment is substantial, the utility may, with approval of the Commission, amortize the amount of the adjustment to this Account over future operating periods.

a. Staff's Position

According to Staff witness Anderson, AIU's gas utilities attempt to treat every instance associated with storage field adjustments in the same manner, while there are actually distinctions in the types of storage adjustments. Mr. Anderson states that AIU's gas utilities are experiencing two different types of storage adjustments: physical losses and underground storage performance variations. Staff says physical losses refer to a known gas loss that can be attributed to a specific event at the storage field and occur as a result of the normal operation and maintenance of the storage field or even as a result of a leak within the storage field itself. Staff claims that underground storage field performance variation refers to changes in the storage field inventory, resulting in the need to add or subtract from the inventory at a storage field, which can not be attributed to a specific physical incident. Underground storage field performance variations, Staff states, are normally detected after an engineering evaluation by the deterioration of the performance of an underground storage field.

While not necessarily agreeing with Staff's delineation of underground storage adjustments into two categories, Staff says AIU does not dispute Staff's explanation or

description of the two categories. Instead, Staff says AIU maintains that both types of underground storage adjustments should be recorded in Account 823. In contrast, Staff witness Everson argues that performance variations are more properly recorded in Account 352.3 (rate base), and physical losses in Account 823 (expense). According to Staff, the contested issue here is the proper accounting treatment for AIU's performance variations.

Staff claims its proposal to place performance variations in Account 352.3 involves the basic mechanics associated with operating a storage field and that the majority of the performance variations result from gas migration. Specifically, Mr. Anderson states that natural gas is injected into an aquifer storage field above the pressure of the water in the aquifer. He says the natural gas injected will expand until the gas pressure and the water pressure reach equilibrium if there are no additional injections or withdrawals and a steady state is allowed to exist. In most aquifer storage fields, Staff says normal operation usually results in an average gas pressure above the aquifer pressure in the storage reservoir. As a result, Staff claims a small portion of the working or top gas tends to migrate to non-recoverable base gas over time, causing underground storage field inventory variations.

Mr. Anderson states that when gas is removed during the storage field's withdrawal cycle, the gas pressure within the field declines, allowing water to return to areas that had previously contained gas. According to Staff, each year, a utility injects gas that moves the water out, but the water returns when the utility withdraws the gas. Staff contends that because of this cycling of the storage field, a portion of the field's inventory also tends to migrate from working or top inventory to non-recoverable base gas.

AIU asserts that there are three major factors requiring the need for a utility to add gas to a storage field: (1) errors introduced over long periods of time through engineering calculations, (2) numerous gas losses that occur that are not estimated because they are unknown or are of a small magnitude, and (3) accumulated clerical and accounting errors, metering inaccuracies, and other operational/maintenance losses are the. Staff states that neither it nor AIU has been able to identify a method to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base gas.

Staff believes that AIU accuses it of ignoring AIU's evaluation that uses the Tek Methodology, which AIU claims demonstrates that physical losses are occurring. The Tek Methodology is a gas loss calculation methodology presented in Appendix I of M. R. Tek's textbook, "Underground Storage of Natural Gas—Complete Design and Operational Procedures" ("Tek Methodology"). Staff says it is not ignoring AIU's evaluation; instead, Staff claims it is attempting to clarify AIU's analysis. Staff also disputes AIU's assertion that migration is not the major factor in the cause of or the need for performance variation adjustments. While Staff does not dispute that the three factors AIU identified can contribute, Staff argues that common sense suggests these are not the major factors causing performance variations.

Regarding the first factor, errors introduced over long periods of time, Staff states that since 2005 AIU has been making annual or nearly annual adjustments to all of its storage fields' inventory volumes. Staff also indicates that AmerenCILCO has made storage inventory adjustments since at least 1996, and passed those costs on to ratepayers. In Staff's view, there should not be any long-term accumulation of errors given the frequency with which the AIU makes storage adjustments.

Regarding the second factor, gas losses that occur that are not estimated because they are unknown or of small magnitude, Staff says that AmerenCIPS recorded physical losses as small as 136 million cubic feet (-Mcf) during the test year, while AmerenIP recorded losses as small as 26 Mcf. Staff argues that comparing the volumes of these physical losses, which AIU takes the time to identify and estimate to the magnitude of the annual adjustments (20,000-40,000 Mcf for AmerenCIPS; 3,445-228,102 Mcf for AmerenIP), demonstrates that any amounts that are too small for AIU to identify or estimate should be significantly less than the volumes AIU assigns to performance variations.

Regarding the third factor, accumulated clerical/accounting errors, metering inaccuracies, and other operational/maintenance losses, Staff asserts that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff claims that meter accuracies are provided in a +/- 0.5 to 1% range. According to Staff, this means that metering could contribute or even reduce or create a negative loss of gas. Staff adds that AIU indicated, for at least its Hillsboro Storage Field metering, that its metering uncertainty is much less or about 0.25%. This demonstrates, Staff argues, that AIU has the means to reduce metering uncertainty. Staff believes metering errors should not be a major contributor to performance variations. Regarding other operational or maintenance losses, Staff maintains that AIU identifies and estimates fairly small gas losses and adds that AIU makes frequent annual inventory adjustments.

Staff argues that in a well-managed underground storage field operation, engineering estimates of physical gas losses should be reasonably accurate, unknown physical losses should be small, and metering errors should be determined and corrected as part of routine maintenance. Staff also contends that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff says AIU has not demonstrated that any of these potential losses are significant or that the volumes associated with them would cause performance variations.

Staff claims that the need to significantly increase the non-recoverable base gas at AmerenCIPS' Sciota storage field is an indication that gas has been migrating on a regular basis in prior years. According to Staff, this is in direct contrast to AIU's position that all the annual adjustments at issue in this case are due to gas that has physically left the storage fields, and that migration is not causing these adjustments or migration is not occurring.

According to Staff, AIU complains about this being the first proceeding where it has been confronted with the concept of performance variations, and thus, has not had the opportunity to fully analyze the issue. However, Staff states that in Docket No. 02-0717, AmerenCILCO's 2002 purchased gas adjustment ("PGA") proceeding, not only did the Commission place AmerenCILCO on notice that at the earliest time possible it should treat and recover those storage adjustments as base rates, but Staff also indicated the proper accounting treatment would either be Account 352.3 or Account 823. (Staff Initial Brief at 75-76, citing Docket No. 02-0717, Order at 5) Staff also states that in Docket No. 03-0696, AmerenCIPS' 2003 PGA proceeding, wherein AmerenCIPS attempted to recover storage adjustments through the PGA, the Commission indicated that the costs in question are recoverable through base rates either through Account 352.3 or Account 823. (*Id.*, citing Docket No. 03-0696, Order at 5) Despite AIU's protests in the instant proceeding, Staff claims the appropriate accounting treatment for its storage adjustments has been a concern between AIU and the Commission for some time.

AIU asserts that the amounts stated in the accounting of the losses should match the physical inventory amounts in the field. AIU is concerned that if the losses are continued to be accounted for as unrecoverable cushion gas, then the accounting numbers will eventually exceed what the field could physically hold as unrecoverable cushion gas. Staff contends that this is true only if AIU's view of how performance variations occur or what they represent is valid. Staff adds that if the accounting losses exceed what the field could physically hold as unrecoverable cushion gas, then AIU, after the appropriate engineering analysis, would have reason to request an alteration of how it accounts for its performance variations.

AIU cites the Order in Docket No. 04-0779, wherein the Commission allowed Nicor to recover in base rates costs that it had been recovering through its PGA clause as an operating expense. AIU claims that the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823. Staff, however, suggests it is unclear whether AIU's situation is the same as Nicor's based on the language in the Order in Docket No. 04-0779.

Staff states that in Docket Nos. 07-0241/07-0242 (Cons.), Peoples used 3.5% of injected volumes as additional base gas (base gas is accounted for in Account 352.3) to support Manlove Storage Field's performance. According to Staff, the Peoples witness stated that the gas in the Manlove reservoir is under pressure and tends to expand, radially invading new areas, and when this occurs some of the gas is inevitably trapped as cushion gas. (Staff Initial Brief at 77, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 105-106) Staff believes the discussion in the North Shore/Peoples Order supports Mr. Anderson's testimony regarding the existence and role of gas migration in performance variations.

Ms. Everson calculates an adjustment to reflect the proper accounting treatment of gas losses based on Mr. Anderson's testimony regarding the nature of the gas losses experienced by AIU. Staff states that losses that are not attributable to a specific cause

or incident can be characterized as storage field performance variations, and this gas, which is not expected to be recovered, should be classified as ~~on~~“non-recoverable base gas” and recorded in Account 352.3. According to Staff, Account 352.3 represents non-recoverable gas that can not be physically recovered when the field is abandoned and, therefore, amounts related to this gas loss should be capitalized and depreciated. Staff reports that none of the AIU gas utilities recorded losses in Account 352.3 from 1997 through 2006. Staff asserts that some of the variations AIU recorded in Account 823 were field performance variations and should be classified as non-recoverable gas and recorded in Account 352.3.

Ms. Everson also recommends that future gas losses should be recorded based on the nature of the loss. She says physical losses should be expensed in the period incurred in Account 823, while adjustments for underground storage field performance variations should be recorded in Account 352.3 and subject to depreciation. AIU responds that to properly adjust in this manner, gas losses identified as performance variations in other years would need to be adjusted from Account 823 to Account 352.3, and that such an adjustment would need to be made for performance variations that occurred within the last 10 years.

In response, Staff indicates that the adjustment to reclassify a portion of the 2006 test year cost of gas storage losses from Account 823 to Account 352.3 does not change their recoverability, only the manner in which they are recovered. Furthermore, Staff disagrees that amounts recorded to Account 823 in the past 10 years would have to be reclassified. Ms. Everson states that these adjustments will not require any other adjustments be made, to either the current rate case’s rate base or AIU’s books, for gas storage losses charged incorrectly to Account 823 in prior years. Staff says the gas storage losses from prior years have already been recovered by AIU through the rates charged during those years. According to Staff, to now reclassify and include those amounts in Account 352.3 would result in double-recovery, since the ratepayer has already paid for these costs through prior years’ charges. In Staff’s view, while the costs of prior years’ performance variations should have been charged to Account 352.3 as well, the fact is they were not. Instead, Staff claims they have been completely recovered through the rates charged to ratepayers during those years, thus making the manner in which they should be recovered a moot issue.

Staff says that in surrebuttal testimony, AIU agrees that no reclassification of prior years’ costs associated with AmerenCILCO’s storage fields would be necessary. AIU maintains that a reclassification is needed for the prior years’ costs associated with AmerenCIPS’ and AmerenIP’s storage fields. The basis for this assertion is that the amounts included in AmerenCIPS’ and AmerenIP’s last rate case for Account 823 expenses are not adequate to cover the charges made to this account in subsequent years. Staff believes AIU’s reasoning is without merit. Staff argues that in the years between rate cases, the actual charges incurred for any expense has the potential to be less than or greater than the amount that was included for that expense in the last rate case. Staff describes this situation as regulatory lag. Staff claims such differences are not allowed to be considered in rate cases establishing the revenue requirement for

future periods. Assuming such a situation did exist with respect to Account 823 charges, Staff contends it was known by AIU at the time of the initial rate case filing and yet AIU made no attempt to include the shortfall in its revenue requests. Staff asserts that such actions would constitute retroactive ratemaking.

In its Reply Brief, Staff disputes AIU's suggestion that what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas unaccounted for in underground storage operations due to other causes. Staff argues that if all storage adjustments, regardless of nature, could be properly recorded to Account 823, there would be no need for Account 352.3 to have ever been included in the Chart of Accounts. According to Staff, the reason why both Account 352.3 and Account 823 are necessary is to recognize the accounting difference between capital and expense items. Staff says Account 352.3 is a capital account and Account 823 is an expense account. Staff maintains that non-recoverable base gas is a capital cost. Staff insists that it would be a violation of accounting theory to charge such costs to an expense account as AIU advocates.

Staff also takes issue with AIU's statement that at the time of the last rate case these costs were not included in the base rates and therefore have not been collected. Staff says this statement refers to AmerenCILCO's storage field adjustments. According to Staff, the costs at issue here have been completely recovered through AmerenCILCO's PGA and, therefore, were not included in the base rates in AmerenCILCO's last rate case. To have done so, Staff argues, would have resulted in double recovery; first through base rates and then again in the PGA.

AIU points out that the AmerenCILCO's 2005-2007 PGA reconciliations are still pending a final Commission Order. Staff claims that, while this is technically true, AmerenCILCO has already recovered the costs for these years and would only have to return any amounts it collected for costs that may be deemed imprudent. (Staff Reply Brief at 46, citing 83 Ill. Adm. Code 525.70(b)) Staff says such an imprudence finding would still make AIU's reclassification argument moot since any costs found to be imprudent would not be allowed to be recovered through base rates either.

Staff argues that because there is no method for allocating between physical losses and migrating gas, the total amounts of performance variation adjustments must be charged entirely to either Account 352.3 or Account 823. Staff claims the costs can not be allocated even though they might contain elements of both physical losses and non-recoverable base gas. Staff asserts that as a result, neither account will be the perfect fit. The goal, in Staff's view, must be to use the account that most accurately reflects the true nature of the performance variations. Staff contends that this is Account 352.3 based on: (1) Mr. Anderson's arguments that the majority of performance variations are the result of gas that has migrated to non-recoverable base gas; (2) AIU's annual storage field inventory adjustments that reduce cumulative losses from inaccurate metering, small gas losses, and clerical errors, which in a well-maintained storage field operation should already be minimal; and (3) AIU's failure to show that the

gas losses associated with performance variations have physically left the storage fields.

b. AIU's Position

AIU provides four reasons why the Commission should reject Staff's proposal. AIU states that the language of Account 823 makes clear that "~~performance variations~~" are properly accounted for in Account 823. AIU asserts that Staff concedes that not all performance variations are in fact migrations to non-recoverable base gas, so transferring all "~~performance variations~~" from Account 823 to Account 352.3 is improper. AIU contends that the Commission has determined that gas losses are properly accounted for in Account 823. Finally, AIU claims transferring gas loss amount from Account 823 to Account 352.3 would require adjustments to rate base for the prior years.

AIU asserts that the language of Account 823 is broad, encompassing gas that is either lost or is otherwise unaccounted for due to cumulative inaccuracies of gas measurements or other causes. In AIU's view, an inventory adjustment for gas that is unaccounted for any cause is properly included in Account 823. AIU asserts that there is no requirement in the language of Account 823 requiring that lost gas recorded in that account relate to gas lost in a specific incident, or even that lost gas recorded in Account 823 be a "~~physical~~" loss of gas.

AIU claims that the types of "~~performance variations~~" Mr. Anderson refers to, such as errors introduced over long periods, losses that occur that are unknown or of small magnitude, and accumulated clerical errors, metering inaccuracies, and other operational/maintenance losses, are the exact "~~cumulative inaccuracies of gas measurements~~" that should be recorded in Account 823. AIU believes that even what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas "~~unaccounted for~~" in underground storage operations due to . . . other causes."

AIU asserts that Account 352.3 does not refer to the calculation or recording of gas losses. Account 352.3, AIU argues, refers to gas in the reservoir, so it is not an appropriate account in which to record lost gas. According to AIU, the gas described by Mr. Anderson as a performance variation is not in the field reservoir and so is lost. AIU claims it is incorrect to account for virtually all of the "~~lost~~" gas in Account 352.3, and Mr. Anderson's testimony does not support the wholesale transition of amounts in Account 823 to Account 352.3. In AIU's view, Mr. Anderson's performance variations are lost gas, and as such should be recorded in Account 823. AIU says that, although there may be an appropriate distinction between physical losses that can be estimated with engineering calculations and losses that can not be estimated, there is no basis for a different accounting treatment of measurable physical losses and other gas losses from a storage field.

AIU states that reservoirs can not hold an infinite volume of gas, and in its present form, AIU believes Staff's recommendation to continually transfer performance variations to non-recoverable base gas does not take into account the ability of the reservoir to hold these volumes of gas. AIU asserts that continually adding performance variation adjustments to the non-recoverable base would eventually cause the amount of gas recorded in Account 352.3 to exceed the capacity of the reservoir to hold gas, at least from an accounting standpoint. AIU also claims it would cause rate base related to the gas storage field to increase substantially over time.

AIU claims that some performance variations are physical losses of gas, and that not all performance variations represent migration to non-recoverable base gas. AIU further asserts that such physical losses could be recorded in Account 823. The fact that performance variations include physical losses and do not entirely consist of migration to base gas completely, AIU argues, undercuts the rationale for Staff's proposed shift to Account 352.3.

According to AIU, Staff's position is that some, but not all, of the performance field variations described by Mr. Anderson represent gas that has migrated to base gas and should be recorded as non-recoverable base gas. AIU says Staff admits that so-called performance variations can include physical losses of gas as well as gas migrating to non-recoverable base gas. AIU argues that if performance variations can include physical losses, then under Staff's logic, some performance variations are properly included in Account 823. AIU complains that Staff has not changed its recommendations regarding shifting gas losses to Account 352.3 and continues to recommend that all of the so-called performance variations be placed in Account 352.3. AIU avers that if it is possible that performance variation could include actual physical losses, then those performance variations should remain in Account 823.

AIU also complains that Staff does not quantify what part of performance variations are physical losses and what part is migration to non-recoverable base gas. Moreover, Staff agrees that such quantification is not feasible. In AIU's view, Staff established no basis for shifting the costs to Account 352.3, when accounting for such losses in Account 823 is reasonable and appropriate. AIU also claims that Staff has not explained why, if performance variations include physical losses, such losses would not be gas lost through —~~the~~ ^{other} causes." Theoretically, AIU states, some of the performance variation gas could migrate to base gas; however, AIU claims there is no known technique by which to separate performance variations into lost gas or non-recoverable base gas. AIU asserts that these migration losses would be very small in scale. AIU believes it is appropriate to include this gas loss as part of the annual gas loss adjustment in Account 823.

This proceeding, AIU asserts, is the first time AIU has been confronted with the concept of performance variations. AIU also says that the term "underground storage field performance variation" is not a term commonly used in the gas industry. AIU asserts that because the concept of performance variations is a new one, AIU has not had the opportunity to fully analyze it. AIU claims it has not been able to identify a

method whereby one could quantify the difference between various physical losses and losses of working inventory to non-recoverable base gas as a result of normal operations. AIU claims it is not aware of any methodology to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base.

In Docket No. 04-0779, AIU says the Commission found that a withdrawal factor, representing gas losses, used by Nicor was appropriately included in Account 823 as an operating expense. (AIU Initial Brief at 223-224, citing Docket No. 04-0779, Order at 39-40) AIU says in that case, a Staff witness testified that expenses related to the operation of a storage field, including adjustments for inventory losses due to cumulative inaccuracies of gas measurements or other causes, should be recorded in Account 823. AIU asserts that even though a portion of the gas was for the replenishment of gas volumes that have become non-effective in contributing to the performance of the storage reservoir, the entire amount was charged to Account 823. The Commission ruling in the docket, AIU states, ultimately approved this treatment of the lost gas. According to AIU, the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823.

AIU complains that Staff's recommendation does not treat gas consistently from year to year. AIU says Staff suggests capitalizing certain gas losses for 2006, thus reducing AIU's test year expense and increasing rate base. If Staff's recommendation is followed, then AIU asserts like gas losses should be evaluated and capitalized as well, and become a part of rate base. AIU claims that taking what Mr. Anderson describes as performance variations and reclassifying them as non-recoverable base gas would, at present, result in increases to rate base.

Ms. Everson disagrees that adjustments to past year rate bases are needed. With respect to AmerenCILCO, Ms. Everson states that AmerenCILCO was recovering these costs through its PGA. At the time of the last rate case, AIU says these costs were not included in the base rates and therefore have not been collected. AIU states it is true that from the 2004 PGA reconciliation and before, the gas losses were collected ultimately through the PGA mechanism and the 2005-2007 reconciliations are still pending a final Commission order. AIU claims that as long as the gas loss costs continue to be collected through the PGA, AIU would agree that these costs should not be included in Account 352.3 for prior years. AIU contends that under Staff's proposal, if these costs are not included in the PGA, then the total sum of those losses from prior years 2005-2007 should be included in Account 352.3.

AIU states that AmerenCIPS (Docket No. 02-0798) and AmerenIP (Docket No. 04-0476) did submit certain gas loss expenses, related to estimated physical losses for discrete events, in Account 823 in their last rate cases. AIU asserts, however, that they did not submit any expenses related to performance variations as that term is currently defined by Mr. Anderson. Therefore, AIU claims there would not be any recovery from the ratepayers for those gas loss expenses and they would not be included in base rates. After the last rate cases, AIU says AmerenIP and AmerenCIPS began recording gas losses resulting from accumulated clerical and accounting errors, metering

inaccuracies, and other operational or maintenance losses (in addition to estimated physical losses related to discrete events) in Account 823. Thus, AIU states that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording. According to AIU, Staff is now proposing that such gas losses should be prospectively recorded to rate base. AIU contends that under Staff's proposal, such costs should have been recorded to rate base in past years. If the Commission adopts Staff's proposal, AIU insists such past year gas loss costs should be transferred to rate base in this proceeding. Otherwise, AIU believes there would be a situation where the higher gas loss costs recorded to Account 823 since the last rate cases for AmerenIP and AmerenCIPS would not be recovered, since they are not presently in base rates and would not be placed in rate base under Staff's proposal in this case. AIU claims that the volumes shown in Mr. Underwood's rebuttal testimony for AmerenIP and AmerenCIPS represent volumes that should be reclassified as non-recoverable base gas if the Commission adopts Staff's proposal, resulting in the associated increases to rate base.

According to AIU, Staff argues that further evidence supporting Staff's position that migration is a major cause of performance variations is AmerenCIPS' adjustment to significantly increase the non-recoverable base gas at its Sciota storage field. AIU claims this position was not set forth in the testimony of any witness. AIU argues that, nevertheless, Staff's argument is without merit because AmerenCIPS' adjustment to increase the non-recoverable base gas at its Sciota storage field represents a determination that gas in the reservoir should be reclassified. AIU claims a detailed reservoir study, as well as a seismic study and a petrophysical review, was completed to specifically identify the amounts of gas in the Sciota field that should be adjusted to non-recoverable base. AIU contends that the results of this study determined how the volumes should be adjusted in that particular instance. AIU says this report, which was based on years of operating experience, new seismic studies of reservoir information, and reservoir simulations, enabled more accurate estimates of the volumes. In the case of performance variations, however, AIU says that it and Staff agree that there is no way to calculate what part of performance variations, if any, is migration to non-recoverable base. AIU insists that the fact that base gas in the reservoir at Sciota was reclassified to non-recoverable base says nothing about the proper accounting of lost gas. AIU also believes this reclassification says nothing about the proper accounting of lost gas, which Staff calls performance variations.

AIU also takes issue with Staff's assertion that transferring performance variations from Account 823 to Account 352.3 would be seamless from a cost recovery standpoint. AIU says Staff rejects AIU's position that the amounts in AmerenIP's and AmerenCIPS' current base rates do not reflect the full amount of expense that these two utilities now charge to Account 823. Staff argues that actual amount of an expense may be greater or less than the amount for which recovery is allowed in a prior rate case. AIU states that, while this is correct for an operating expense, Staff is proposing to switch performance variation amounts to a rate base account. AIU says that if performance variations are recorded in a rate base account, they represent an investment by the utility. AIU claims that, while its current filing recovers the full annual

amount of gas loss expense recorded to Account 823, a shift of that amount to rate base would leave prior years' investment stranded. AIU maintains that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording.

According to AIU, Staff's reference to Dockets Nos. 02-0717 and 03-0396 as supporting the position that the gas loss accounting issue is nothing new are unavailing. AIU says those cases dealt with the question of whether gas losses should be recovered through the PGA or base rates. AIU claims the cases did not address which Account, 823 or 352.3, was the correct account to record such gas losses. AIU adds that they did not address the treatment of performance variations.

c. Commission Conclusion

Currently, AIU apparently records all gas losses in Account 823, which is an operating expense account. Staff proposes that AIU record all gas losses characterized by Mr. Anderson as performance variations in Account 352.3, which is a rate base account. While maintaining its position, AIU claims that if Staff's proposal were adopted, additional changes to rate base accounts for previous years would be required for AmerenCIPS and AmerenIP. Staff disagrees that any additional adjustments would be required.

Staff argues that the migration of gas to nonrecoverable natural gas is likely the primary cause of gas losses, although Staff does not know for sure what portion of gas losses have migrated. AIU does not go quite so far, although AIU does not seem to actually dispute the proposition that a portion of gas losses could easily be a result of gas migration. Instead, AIU relies on the broad language describing Account 823 and appears to suggest that any gas loss could be recorded in Account 823.

The record supports the accounting perspective that a portion of the gas losses should, in all likelihood, be recorded as a rate base item with the remainder recorded as an operating item. Because each of the extreme positions taken here seems likely to be improper, the Commission is faced with a rather difficult decision. The Commission finds the testimony of Mr. Anderson regarding the migration of gas to be the most convincing and, as a result, adopts Staff's proposed adjustments on this issue. The Commission finds that AIU should record gas losses for the test year in Account 352.3 as presented on Staff Schedules 14.04 G. In future rate cases, AIU is free to attempt to quantify the portion of gas losses resulting from the migration of gas and seek different accounting treatment of other gas losses.

Contrary to AIU's assertion, the Commission does not believe any additional adjustments for gas losses prior to the test year are necessary for AmerenCILCO, AmerenCIPS, or AmerenIP. To the extent amounts representing gas losses have been recorded in Account 823 and reflected in operating expenses in prior rate cases, no adjustments are necessary as the change ordered herein will be reflective of the test year and will be effective prospectively. To the extent gas losses have been recorded in

Account 823 and are reflected in AmerenCILCO's PGA reconciliations, as long as the gas losses receive appropriate treatment for the appropriate reconciliations, the utilities will be made whole. Additionally, the Commission directs AIU and Staff to make all reasonable efforts to ensure that gas losses are treated in a manner consistent with this decision for the outstanding 2005-2007 AmerenCILCO PGA reconciliations.

7. Working Capital Allowance for Gas in Storage

a. AIU's Position

AIU proposes that its working capital allowances for gas in storage be \$53,023,000 for AmerenCILCO, \$37,731,000 for AmerenCIPS, and \$99,903,000 for AmerenIP. AIU understands that Staff proposes certain volume adjustments to the working capital allowance for gas in storage. In response, AIU indicates a willingness to accept Staff's proposal, and also proposes what AIU sees as the necessary counterpart adjustments. AIU asserts that if the Commission chooses to accept Staff's pro forma volume adjustments reflecting adjustments for normal weather and changes in leased storage contracts; the Commission should adopt AIU's proposed pro forma price adjustments.

AIU agrees in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. AIU submits that Staff witness Lounsberry's analysis on this issue contains only half of the necessary adjustments. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. Staff's adjustment, according to AIU, assumes that the per unit costs of the test year (2006) are valid in the year associated with Staff's pro forma inventory levels (2008); AIU argues this is not correct.

AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the New York Mercantile Exchange ("NYMEX") natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU avers that on April 8, 2008, that price was \$10.00 per millions of British thermal units ("MMBtu") for the period. Mr. Lounsberry opposes AIU's pro forma adjustment to gas storage working capital to account for the significantly higher prices of natural gas in the calculation of inventory costs for three reasons: he believes that the 2008 prices are now known and measurable or determinable; he claims that AIU price hedge portions of its storage injection gas; and he believes that the 2006 per unit costs are in line with 2007 costs.

AIU asserts that with respect to Mr. Lounsberry's argument that 2008 prices are not known, measurable, or determinable, his own calculations are also predicated on projected (rather than known and measured) forecast volume data. AIU argues that Mr. Lounsberry is implying that the volume adjustments are also not known and measurable. AIU avers that Mr. Lounsberry's premise for his proposed volume

adjustments are two-fold; changes in AIU's leased storage levels and attempting to account for the warmer than normal weather realized during the 2006 test year. AIU argues that Mr. Lounsberry requested —~~expected~~” ending inventories —~~assuming~~” normal weather and utilized these as forecasted volumes instead of historical volumes that occurred during the test year. AIU submits that its request to reflect the forecasted cost of gas injected into its storage fields is no different than Mr. Lounsberry's use of the forecasted ending storage volumes.

AIU contends that part of Mr. Lounsberry's volume adjustment argument stems from his premise that 2006 was a warmer year than normal and that, for the test year 2006, AIU retained more gas in inventory than it would have in a year of normal weather. AIU submits that there are issues in addition to weather that are also important to the cycling of storage fields. AIU avers that it examined the ending inventories in AIU's storage fields, leased and owned on December 31, 2006, and the forecast inventories on December 31, 2008, and made known contractual changes. AIU argues that after this examination, it can not agree with Mr. Lounsberry's volumetric adjustments associated with the difference between 2006 and 2008 weather, as Mr. Lounsberry has outlined a difference in degree days of approximately 10% between 2006 actual and 2008 normal. AIU submits that while such a difference may have a large impact on annual throughput and earnings from the utility's perspective, it would not necessarily make a large difference in how the storage fields are operated. AIU further submits that the specific characteristics of each storage reservoir are another factor affecting the withdrawal plan.

AIU concurs with Mr. Lounsberry's concern that its price hedge portion of the injection gas supply is not reflected in the proposed price adjustments. AIU points out that its risk management policy outlines a hedging strategy for up to 50% of its summer injection requirements. Therefore, AIU asserts it recalculated the projected storage Weighted Average Cost of Gas ("WACOG") for the pro forma test year. AIU submits that utilizing the utilities' hedged positions for the entire period of 2008 currently in place, actual storage inventories and prices through April 2008, and the NYMEX forward strip as of April 24, 2008, this calculation produces WACOGs of \$8.79 to \$9.00 per MMBtu. AIU avers that this result is reasonably comparable to the \$10.00/MMBtu NYMEX strip used previously.

As a result of this analysis, AIU argues it has reduced its price adjustment on a per MMBtu basis, and the impacts that these revised WACOGs have on the storage working gas inventory balance result in AIU's current proposal for gas storage working capital allowance. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side. AIU avers that it is clear that the cost of AIU gas inventories on December 31, 2008, will be equal to or greater than at the end of 2006. AIU notes that in 2006, gas commodity prices at the Henry Hub averaged \$6.74 per MMBtu; while through April 21, 2008, actual Henry Hub gas prices averaged \$9.27 per MMBtu, a 37.5% increase over 2006. AIU avers that the NYMEX forward curve for the remainder of 2008 indicates an

average market price of \$11.11 per MMBtu, reflecting a 65% increase over the 2006 cost levels.

AIU recommends that the Commission adopt the level of working gas inventory in the working capital adjustment that AIU filed in its direct cases. Should the Commission adopt Staff's pro forma volume adjustments, AIU submits that the Commission should further adopt AIU's pro forma price adjustments.

b. Staff's Position

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff points out that AIU witness Wichmann states that AIU does not dispute the rationale for Staff witness Everson's adjustment regarding the accounts payable percentage, but does not agree with the value Mr. Lounsberry assigned to gas in storage.

Staff submits that its recommended alterations to amounts that AIU has requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields. Staff recommends changes to all of AIU's requested volumes due to the determination that AmerenCILCO and AmerenCIPS had known and measurable changes to their test year volumes, AmerenIP's test year volumes had changed and the 2006 test year was not a representative year. Staff points out that in order to calculate the adjustment, Mr. Lounsberry employed the same methodology that Staff used and the Commission accepted in the recent Peoples/North Shore rate cases on this issue, Docket Nos. 07-0241/07-0242 (Cons.).

For known changes, Mr. Lounsberry noted that AmerenCILCO's storage volumes were being increased due to increases in its Panhandle Eastern Pipe Line Company (-Panhandle") storage volumes effective April 1, 2006, as well as April 1, 2008. AmerenCIPS' storage volumes also changed by having its Panhandle contractual volumes decrease effective April 1, 2008, as well as decreased storage volumes from Texas Eastern Transmission Corporation as of July 1, 2006. Mr. Lounsberry further noted that AmerenIP had increased storage volumes from the Mississippi River Corporation as of May 16, 2006, increased the storage volumes received from Panhandle and ANR Pipeline Company as of April 1, 2006, and reduced storage volumes from Trunkline Gas Company as of April 1, 2006.

According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields, and that warmer weather, in general, creates a situation where more gas remains in the field than the utility had planned. Staff submits that since a utility's working capital allowance is based upon the volumes of gas remaining in storage, this means that a utility's working capital allowance for gas in storage in a warmer than normal year is higher than if it was based upon a year with normal temperature conditions.

Given Staff's concern's, Mr. Lounsberry calculated AIU's storage volumes using a normal 2008 year. Staff asserts this methodology ensures that AIU's storage volumes are normalized, rather than relying on historical storage volumes that are often impacted by temperature conditions that vary from the norm, and also accounts for the known and measurable changes that the AIU made to its storage volumes. Staff submits that Mr. Lounsberry's calculations were based upon AIU's projection of the storage volumes it would maintain in 2008 under the assumption a normal year occurred.

Staff recommends that the Commission adopt its suggested changes and set working capital allowances of \$45,089,000 for AmerenCILCO, \$32,259,000 for AmerenCIPS, and \$82,396,000 for AmerenIP.

c. CUB's Position

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions.

AIU, according to CUB, did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations that AmerenCILCO decrease its requested amount by approximately \$4,359,000, that AmerenCIPS reduce its requested amount by approximately \$13,669,000 and that AmerenIP reduce its requested amount by approximately \$5,105,000.

d. Commission Conclusion

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff submits that its recommended alterations to amounts that AIU requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields.

AIU agreed in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the NYMEX natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU

avers that on April 8, 2008, that price was \$10.00 per MMBtu for the period, which was subsequently adjusted in an effort to reflect the fact that AIU hedges portions of the injection gas supply. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side.

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions. According to CUB, AIU did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations.

The Commission finds Staff's proposal to make pro forma adjustments to the working capital allowance to reflect revisions in storage volumes to be reasonable and it is hereby approved. The Commission believes that these adjustments will better reflect AIU's cost structure that will be in place when rates established in this proceeding take place. While Staff objects to AIU's proposal to make adjustments to the price associated with gas in storage, the Commission believes it appropriate. AIU made an adjustment to the proposed price to reflect the fact that it hedges a portion of the gas injected into storage in direct response to Staff's concern. Contrary to Staff's suggestion, the use of NYMEX natural futures contracts is not unheard of in establishing rates. The Commission concludes that in this instance, the price proposal of AIU is reasonable when used in conjunction with Staff's proposed quantities of gas.

As for CUB's proposal, the Commission has established the appropriate CWC allowance elsewhere in this Order and believes there is no point in addressing the issue here.

8. Hillsboro Base Gas Inventory Valuation (Prior Adjustment)

a. AIU's Position

AmerenIP seeks to include in rate base \$10,367,838 associated with base gas inventory at the Hillsboro Storage Field. In doing so, AIU is essentially asking the Commission to revisit its decision in Docket No. 04-0476 disallowing this amount. Even though an appellate court upheld the Commission's disallowance, AIU argues that circumstances have changed since Docket No. 04-0476. AIU wants the Commission to consider the fact that the Hillsboro Storage Field has now been restored to its full —~~use~~ and useful" levels for peak deliverability to system sales customers, which was not the case in the previous proceedings. AIU argues that it is not just the Hillsboro field that is used and useful, the \$10,367,838 cushion gas amount is also used and useful. AIU

claims that AmerenIP is not currently being allowed to earn a return on assets that are used and useful, prudently incurred, and providing full benefits to its customers.

Gas storage operations, AIU argues, benefit its gas customers. According to AIU, system storage provides flexibility and reliability for gas supply to customers that can not be found elsewhere for the same value. AIU says this flexibility on the natural gas system allows for the efficient balancing of supplies and usage. AIU adds that the storage fields provide reliability by being a source of gas supply close to the customers, therefore reducing risk related to facility failure or disruption to the supply of gas.

AIU contends that on-system storage also generates financial benefits for gas customers, by lowering the price of gas. When combined, AIU indicates that the peak day deliverability of AmerenCILCO, AmerenCIPS, and AmerenIP, is 1,182,264 MMBtu, with a storage delivery of 578,759 MMBtu (48% of the peak day send out of the combined utilities). AIU asserts that replacing the storage deliverability of AmerenIP with interstate pipeline deliverability would increase the PGA costs by almost \$100 million a year, not including any seasonal differential associated with the commodity purchases. In AIU's view, gas storage provides ratepayer benefits, and AmerenIP should be allowed to recover its reasonable and prudent expenses related to gas storage field operation, including the Hillsboro Storage Field base gas inventory.

In Docket No. 04-0476, the Commission addressed a situation in which AmerenIP had withdrawn cushion gas from the Hillsboro field due to a metering error. As a result of the over-withdrawals from the field, AmerenIP had to replace the withdrawn cushion gas with gas purchased at higher prices than the historical cost of the cushion gas reflected in rate base in Illinois Power's 1993 rate case. The Commission agreed with the Staff, and concluded that the excess of the replacement cost over the historical cost of the cushion gas could not be recovered until the gas is withdrawn from the field at the end of the field's useful life, and that AmerenIP could not earn a return on the excess cost in the interim.

AIU claims that the effect of the decision imposes a penalty on AmerenIP out of proportion to the effect on customers. AIU claims the error provided lower cost gas to customers than they otherwise would have received. AIU states that AmerenIP must bear the financing costs of a portion of its cushion gas for the remaining useful life of the field, which could be 30 years or more. From AIU's perspective, customers receive the double benefit of both the consumed lower priced gas withdrawn from the field and the historical cost of the cushion gas for the remaining life of the field. AIU claims it will essentially lose its investment in the additional costs of the replacement gas. By the time AmerenIP obtains any recovery of the investment, AIU complains that it will have incurred financing costs far in excess of its investment.

AIU proposes at least two ways to address this situation. One is to reflect the full value of the cushion gas in rate base in this proceeding. AIU maintains that customers have benefited both from the lower cost gas through the PGA and avoided financing costs on the additional investment for three years. AIU believes the lost financing cost

over those three years is an adequate revenue impact for AmerenIP, especially since the field has been returned to its full used and useful status. Alternatively, AIU suggests that the Commission could allow it to recover the excess cost, which AIU claims is roughly the cost customers should have paid through the PGA, in this case. AIU says that under this approach, customers avoid several years of financing costs, the inventory is priced going forward as though the metering error were never made, and at the end of the useful life of the field customers will receive even lower priced gas.

AIU also asserts that the management concerns at Hillsboro raised in Docket No. 04-0476 have been addressed. AIU states that Staff witness Lounsberry acknowledges that most of the problems he identifies related to the Hillsboro Storage Field existed prior to 2004, that he has not seen a reoccurrence of those problems, and that he is aware of improvements made in —management oversight” of gas storage at AmerenIP since December 2000. Since 2004, AIU explains that several significant organizational changes and improvements have been made to improve gas operations, which emphasized the importance of the gas storage operations at AmerenIP's gas facilities, and provided continued value to its customers. AIU asserts that improvements have also been made to the operations of the gas storage fields, including concentration on the metering area. AIU notes that new ultrasonic metering installations were performed at Ashmore in 2005, Tilden and Hillsboro in 2006, and Shanghai in 2007, and there are plans to install new metering facilities at Hookdale and Freeburg in 2008. These improvements, AIU asserts, make higher levels of operation performance possible through the availability of better equipment.

According to AIU, several recently-completed capital projects have also contributed to improvements in AmerenIP's operations. AIU states that \$3.1 million in capital expenditures were made in 2006, and over \$7 million of capital expenditures were made in 2007, all related to improving performance at gas storage fields. AIU relates that some of the larger projects include the previously mentioned facility metering projects, water disposal system, hydrogen sulfide ("H₂S") removal facilities, replacing motor control centers, adding gas chromatographs, and replacing a glycol regenerator. AIU claims that these improvements and changes have had a measurable impact on gas storage field performance since 2004. AIU notes that for all AmerenIP gas storage fields, including Hillsboro, there has been no increase or decrease of peak day ratings. Overall, AIU claims that the fields have been performing well and have provided value to the ratepayers, without the storage field customers having to pay more in PGA costs.

In its Reply Brief, AIU states that in Docket No. 04-0476, Staff viewed the disallowance in part as a penalty for poor management at Hillsboro. AIU observes that Staff acknowledges there have been numerous improvements and investments at Hillsboro since 2004. As a result, AIU argues that the past problems do not persist and do not represent present concerns. According to AIU, the concerns about Hillsboro that Staff raised in Docket No. 04-0476 in recommending the disallowance of the \$10,367,838 amount have been addressed. In AIU's view, because AIU addressed these concerns, the rationale for penalizing AmerenIP for its poor management at

Hillsboro has been eliminated, and the \$10,367,838 disallowance should be reconsidered.

b. Staff's Position

Staff objects to AIU's request to revisit the issue of revaluing a portion of the Hillsboro Storage Field's base gas inventory. Staff says AIU requested the Commission's permission to increase the value of its recoverable base gas inventory at Hillsboro by \$10,367,838 in Docket No. 04-0476, AmerenIP's last gas rate case. AmerenIP's basis for that previous request, Staff states, was that it experienced a significant gas measurement error at its Hillsboro field during the period November 1993 through October 1999. AmerenIP estimated that the impact due to the measurement errors caused its measurement records to overstate its actual gas inventory by 5.8 billion cubic feet (Bcf). AmerenIP also claimed that, as a result of the measurement error, it withdrew gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes, and withdrew gas from its recoverable base gas inventory. According to AmerenIP, the impact of this activity was that it withdrew recoverable base gas that was lower-priced than the gas it had placed in the field during the injection season, resulting in AmerenIP's request to increase the value of its recoverable base gas inventory at Hillsboro by \$10,367,838.

Regarding AIU's primary proposal, to include the cost of gas in rate base, Staff says this methodology was fully discussed and argued before the Commission in AmerenIP's last rate case. At that time, the Commission agreed with Staff and denied AmerenIP's request to revalue the base gas inventory at Hillsboro. Staff notes that AmerenIP appealed the Commission's decision to deny its request to revalue the base gas inventory at Hillsboro, and on October 2, 2006, the appellate court affirmed the Commission's decision. In Staff's view, AIU did not provide any new arguments or information in this proceeding for the Commission to consider that would support a change in the Commission's prior decision.

With regard to AIU's secondary proposal to create a regulatory asset and amortize it over two years, Staff argues this would provide no benefit to ratepayers in that it would essentially allow AmerenIP to expense an item that would normally be a rate base item. Staff claims AIU's proposal would only provide a benefit to AmerenIP without a corresponding benefit to its ratepayers. AIU claims that it was not attempting to reverse the Commission's prior decision in AmerenIP's last rate case or to prove the Commission wrong. Instead, AIU indicates that it is asking Staff to give new consideration and weight to the fact that the Hillsboro field has been restored to its full —~~use~~ and useful" levels for peak deliverability to system sales customers and that the full amount of the cushion gas is being used to provide that full —~~use~~ and useful" level of peak deliverability. According to Staff, AIU is advocating a reversal of the Commission's prior Order. The Commission's Order on this issue in Docket No. 04-0476 not only provided a conclusion on this issue, but also clearly directed the manner in which AmerenIP would recover its costs in the future. Staff says the cost will

ultimately be recovered through the PGA clause when the gas is withdrawn and delivered to PGA customers.

Staff claims that AIU's only basis for reversing the Commission's prior decision is that the Hillsboro field is now fully —~~use~~ and useful" and it provides peak deliverability. According to Staff, the Commission's Order in Docket No. 04-0476 clearly provides a separate discussion and conclusion regarding the issue of the inventory revaluation, versus the used and useful discussion and conclusion. Staff also contends that AIU is in error to claim that the Hillsboro field was not at peak deliverability during AmerenIP's last rate case. Staff says the Commission's Order clearly indicates that IP had restored the peak day deliverability rating of the Hillsboro field to its design level prior to the 2003-2004 winter season, which is prior to AmerenIP's rate case filing in Docket No. 04-0476. In Staff's view, AIU presented no basis for a reversal of the Commission's prior decision in Docket No. 04-0476. Staff recommends that the Commission deny AIU's request to revalue the Hillsboro field's base gas inventory by \$10,367,838, or, in the alternative, to account for this value in another manner.

c. Commission Conclusion

Despite AIU's protests, it appears to the Commission that the circumstances here are identical to those present in Docket No. 04-0476. In that case, the Commission rejected AmerenIP's proposal to include in rate base the additional base gas at Hillsboro, which is the request AIU repeats here. The Commission previously decided this question, this decision was affirmed by the appellate court, and the Commission can discern no change in facts or circumstances that warrant revisiting or reconsidering the question here. AIU's proposal is rejected.

9. Hillsboro Base Gas Inventory Valuation (New Adjustment)

a. AIU's Position

AmerenIP proposes to add \$2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims that the addition is necessary to account for base gas lost through a valve leak. According to AIU, the added volume represents gas that is now used and useful in providing service to customers, and the cost of the added gas has been prudently incurred.

AIU states that tests on newly-installed ultrasonic gas meters at Hillsboro in January 2007 revealed that base gas volumes at Hillsboro must be adjusted. After the installation was completed, AIU says comparisons were made between the flow through the existing metering and the new metering. After analyzing the data, AmerenIP indicates it determined that 1,109,964 Mcf of additional gas was actually withdrawn but not reflected as withdrawals from the field from 2001-2007. AmerenIP says it replaced this 1,109,986 Mcf of gas by the end of the 2007 injection season, resulting in an adjustment of an additional \$2,841,000 to the Hillsboro base gas account.

AmerenIP determined that there was a valve leak in the old metering equipment, which allowed gas to pass undetected and unmeasured through the secondary meeting run, over the period 2000 to 2007. AmerenIP says this resulted in a portion of base gas being withdrawn during the years 2001 to 2004, which was delivered to AmerenIP's sales customers. This base gas was replaced during the next injection season after the gas was withdrawn. AIU asserts that the replacement was required in order to meet the supply requirements of AmerenIP's gas customers because the proper operation of the storage field requires that the base gas be present to provide pressure support for the field. To assure the field can cycle 7.6 Bcf and peak at 125,000 Mcf/day, AIU explains that the field must have the established level of base gas and working gas. According to AIU, this is an investment that was required to meet the needs and requirements of AmerenIP's customers. AIU believes that the gas loss at Hillsboro was justifiably re-injected into the reservoir.

AIU argues that it is in the best interest of the ratepayers and AmerenIP to make regular adjustment for gas losses. Deferring an annual adjustment until ironclad support of a shortfall in inventory is in hand, AIU avers, could potentially cause a storage field to fall short of its delivery target, due to the cumulative effect of not making annual adjustments. AIU claims a shortfall in storage field gas could cause it to buy spot-market gas or overrun a pipeline contract to make up the shortfall. AIU says this would be an additional expense to ratepayers. AIU asserts that if it does not make timely additions to inventory it is possible that at some time in the future it will need to add a relatively large amount of gas to make up for the cumulative shortfall. AIU contends that this gas, in all likelihood, would be more costly than an annual addition of smaller amounts of gas.

AIU reports that Staff witness Lounsberry recommends disallowance of the \$2,841,000 addition to the Hillsboro base gas account. Mr. Lounsberry originally set forth four reasons for disallowing this request to increase its recoverable base gas costs. Mr. Lounsberry argued that: (1) he does not consider AmerenIP's logic in determining the timing of the metering error at Hillsboro during the years 2001–2004 as valid; (2) AmerenIP has inadequate support for the assigned value; (3) he questions the validity of certain assumptions that AmerenIP made as part of the calculation; and (4) he states that, given the purported history of problems at Hillsboro, he would have expected AmerenIP to have conducted a review of the integrity of the valve at a much sooner date.

Mr. Lounsberry argues that it was not reasonable to assume that the valve leak in question began in 2000. AIU responds that while the start date of the valve leak is uncertain, AmerenIP selected 2000 as an estimate for the start date because that was the half-way point between when the valve was rebuilt (1993) and when the leak was discovered. AIU believes use of the halfway point is also reasonable because the 5.8 Bcf correction that the 2004 Hillsboro Study recommended would have accounted for all metering errors, including withdraw metering errors, up to 2000 only. AIU states that after 2000, as a result of AmerenIP's 1999 Meter Study (Peterson), the method of operating the storage field changed so that injection meter error was eliminated. AIU

adds that only data from the 1994 to 1999 time period was modified in the reservoir simulator's data deck to determine that the inventory shortfall was 5.8 Bcf. Injection data from 2000 to 2003 was accepted at face value, AIU says. Hence, AIU claims the impact of the valve leak metering error had already been corrected for the period up to 2000, and need only be accounted for thereafter.

Mr. Lounsberry's second concern is that AIU has not sufficiently supported the \$2,481,000 assigned value of the base gas cost. Mr. Lounsberry cites two bases for his position: AmerenIP's inconsistent operation of Hillsboro makes it unreasonable to rely on reservoir data, and AIU's current proposal conflicts with data reviewed in a prior rate case. AIU asserts that no party challenged the two forms of input data in the data plot that AmerenIP uses to support the measurement error correction. AIU says the first data input is gas volume data, which are from the new ultrasonic metering, not the old plant metering, and therefore are considered to be accurate. AIU indicates that the second data input is pressure data, which are measurements of the wellhead pressure from the Truitt #1 pressure observation well. According to AIU, at no time has Mr. Lounsberry questioned the validity of this wellhead pressure measurement. AIU states that while Mr. Lounsberry asserts that AmerenIP may have employed other —superior” methodologies in past rate cases, AmerenIP used valid reservoir engineering techniques to determine gas loss. AIU argues that it is not required to use any one particular type of study to demonstrate prudence. (AIU Initial Brief at 108-109, citing Illinois Power Co. v. Illinois Commerce Comm'n., 339 Ill. App. 3d 425, 439 (5th Dist. 2003) (“Section 9-220(a) of the Act does not set forth any specific type of analysis that a utility must perform to show that its costs are prudent.”))

AIU agrees that the reservoir model would be an appropriate method to determine gas losses; however, AIU says the reservoir simulator was not used to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections. Further, AIU claims techniques such as hysteresis curves and reservoir simulation techniques are not viable at Hillsboro at this point in time due to the present state of the data (in the case of the simulator), and the variation in gas volumes cycled (in the case of hysteresis curve analysis). AIU asserts that it used the best data available in its calculations. AIU maintains that the data available are sufficient to allow the base gas adjustment to be calculated based on sound engineering judgment. AIU states that as gas is injected and withdrawn from a reservoir, wellhead pressure will vary. AIU says this change in pressure can be, and is, utilized by AmerenIP to monitor reservoir performance via multiple techniques such as reservoir simulation, hysteresis curve analysis, the Tek Methodology procedure, and many other techniques. AmerenIP says it utilizes this information at all of its fields in one form or another as part of its ongoing inventory verification process. AIU concludes there is no basis to believe that the result of these two sources of data is in any way unreliable.

AIU asserts that Mr. Lounsberry ignores the results of the 2007 Hillsboro inventory adjustment. In 2006, when the 2006 Gas Loss Adjustment Report was written, AIU says it believed that the hysteresis curve analysis, modeling, and neutron

log evaluation for Hillsboro were, in fact, affected by the injection of additional gas into the field. But AIU claims that it also recognizes that gas losses are occurring on an ongoing basis in gas storage fields. In light of this fact, AmerenIP decided to inject 200,000 Mcf in order to begin addressing the known shortfall. AmerenIP states that 200,000 Mcf is 2.5% of the working gas volume in Hillsboro, which it claims is within the typical range for gas losses by Illinois gas utilities. Further, AIU claims it was able to confirm in 2007 that 200,000 Mcf was a conservative and reasonable estimate to use to address gas losses in the reservoir.

Staff's view that AIU's current proposal conflicts with data reviewed in a prior rate case is also incorrect, AIU argues. Staff believes that the 5.8 Bcf adjustment contained in the 2004 Hillsboro Report overlaps with the 1.1 Bcf adjustment under instant review. However, AIU asserts that the metering errors described in the 2004 gas rate case were corrected in the fall of 1999. AIU says the inventory correction volume of 5.8 Bcf quantified the effects of the accumulated metering errors from 1993 to 1999 and was reinjected into Hillsboro in 2004 and 2005. After 2000, as a result of Peterson's 1999 Metering Study, AIU claims the method of operating the storage field changed so that injection meter error was eliminated. Therefore, for modeling purposes and to allocate the 5.8 Bcf correction back in time, AIU maintains that only data from the 1994 to 1999 injection seasons were modified in the database. AIU says the analysis of the metering error that AmerenIP performed in 2007 after comparing the newly installed ultrasonic meters to the existing metering led AmerenIP to conclude that the leaking valve induced error began during 2000. AIU insists that the 1.1 Bcf correction was only applied beginning with the 2000 to 2001 withdraw season and ending with the 2006 to 2007 withdraw season. AIU maintains that there is no overlap of the requested adjustments, as this case requests inventory corrections for the period 2000 to 2003. At Hillsboro, AIU relates that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis utilizing hysteresis techniques. However, AIU believes other information is available to support the proposed inventory adjustment.

AIU avers that Mr. Lounsberry's third concern, that certain assumptions within AmerenIP's calculations are not robust, is also unfounded. AIU says Mr. Lounsberry laid out 5 specific concerns with the gas-volume calculation:

1. Valve leakage could have worsened over time.
2. Other errors could have caused the differences.
3. The 2.75 % error was used even when valve was fully opened.
4. Concern about only using the January 24 to February 25 time period and then extrapolating over 7 years.
5. All meters in series will show a percent difference.

AIU claims it has addressed all five concerns. AIU says the first concern makes a faulty implicit assumption: that the valve leak had worsened over time, and that the calculation thus overstated initial volumes that were not measured. AIU says it has no indication that the leak did worsen over time. Therefore, AIU concludes the 2000 start

point for the full leak is an appropriate assumption. In addition, AIU asserts that it would be difficult to identify when or at what rate such worsening of the leak would occur.

AIU claims the second concern, that there are other potential causes for the observed measurement error/gas-volume discrepancy, is unsubstantiated. Staff suggests that AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. AmerenIP says that although it can not determine that —all of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP reasonably believes that the leaking valve or the orifice plates were the dominant sources for the observed errors. Staff further suggests that the metering review was incomplete, but AIU says it offers no specifics as to what should have been reviewed.

According to AIU, there is no justification for Mr. Lounsberry's position that the reference to volumetric variance resulting from pressure and temperature variance —~~confirms~~ the possibility of —~~significant~~ variances in measured values. AIU says the differences described for the temperature and pressure transmitters were from the period that comparison testing was conducted using the new ultrasonic meters and in-place South Pipeline (—SPL”) orifice metering on February 21-22, 2007. AIU claims the only data that exists on a daily basis from which any volumetric error can be calculated is the daily SPL withdrawal numbers. The correction volume, AIU states, was calculated based on information available to make the correction. AIU adds that the referenced transmitters are calibrated each fall prior to the withdrawal season and adjusted as needed so any variances in measured values are minor.

Mr. Lounsberry's third concern, that the 2.75% error rate for a fully-open valve is unexpectedly high, is, in AIU's view, also unwarranted. AIU claims the error-rate calculation was based on an analysis of actual data by AmerenIP. AmerenIP says it determined the 2.75% error by comparing actual daily flows from both the SPL and North Pipeline (—NPL”) orifice runs, adjusted for the correction to the NPL flows for orifice installation problem and then correcting the SPL flow so that the daily sum of the adjusted NPL and corrected SPL flows matched the ultrasonic meter daily volume. AIU insists that the correction method made use of the best information available. AIU says the historical daily 2000 to 2007 volumetric data was available for the NPL and the SPL, but not by primary or primary and secondary run volumes. According to AIU, it would therefore be impractical to try to apply separate primary and secondary run corrections. AIU claims that based on the hourly test at 1600 Mcf/hour, with both primary and secondary open, the accumulated volume error percentage was 2.246%, and not negligible. AIU states that the flow exceeding 35,000 Mcf/day SPL correction of 2.75%, derived from correcting the daily NPL and SPL volumes to ultrasonic meter volumes, is comparable to the test measured error over one hour of 2.246%.

AIU says it attempted to identify all causes for the differences between the SPL orifice volumes and the ultrasonic meter volume. AIU insists the testing performed was thorough and resulted in the leaking valve being identified as the most significant problem that resulted in the differences in measured volumes. AIU also states that real

time testing requires the field to cease normal withdrawal operations and requires operators to modify flow rates, open and close valves, and verify readings at several points along the data communications path. When testing the SPL meters, AIU says withdrawals to the NPL are stopped, and the flow rates are adjusted for testing which impacts the gas dispatch function. AmerenIP concluded that it had identified the cause of the measurement error and it would be unreasonable to further disrupt the dispatch function and tie up operators for long periods of time to determine the source of errors beyond what was performed. In AIU's view, Mr. Lounsberry's theoretical concerns ignore AmerenIP's reasoned and reasonable approach to the leak investigation and calculations.

According to AIU, Mr. Lounsberry's fourth concern, that the leak measurements were extrapolated from data gathered during a one-month review, overlooks the fact that the review period could not have begun sooner, nor been fair and representative of the leak after February 20th. AIU indicates the ultrasonic meters at Hillsboro were placed into service on January 23, 2007, so a comparative analysis could not have been started sooner than that date. On February 20th, AIU says the NPL plates were installed correctly and the SPL secondary run problem was discovered and isolated. AIU claims any information collected after corrective action was completed would not be useful for determining prior period corrections. In AIU's view, the review period selected represents the best available information regarding the measurement error. AIU believes that since the information from the review period was the best information available, it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

AIU argues that Mr. Lounsberry's position, that conditions during the 1-month review period may not have mirrored conditions during the rest of the 7-year adjustment period, does not support a conclusion that the estimate of the leak was unreasonable. According to AIU, there were no physical changes made to the piping on the SPL meter runs from 1999 to 2007. AIU says the orifice plates in both runs have not been changed, nor has the computation method for volumes changed so the measurement system for the SPL orifice meter runs over the prior 7 years is identical to the system used during the month for the correction. AIU claims the test included flow rates over the entire flow range simulating flowing conditions. The actual flows, AIU asserts, were matched daily back to the tested flows to come up with the error amounts. AIU contends there is no reason to believe that circumstances did not remain reasonably similar throughout the 7 year time period. Given that there were no significant changes, AIU believes its extrapolation was appropriate.

Mr. Lounsberry's fifth concern, that meters connected in series will typically exhibit some variance, is de minimis, according to AIU. AIU acknowledges that there will be variances between meters. AIU believes, however, that the impact of any such variances on the measurement error calculation will be minimal. AIU says the measurement error calculation is an estimate. AIU states that the ultrasonic meter measurement uncertainty is much less than volumes determined by the orifice meter system. AIU says it has high confidence in the computed volumes from the ultrasonic

meters and believes that the variances, and their impact on measurement error calculation, would not be significant.

In AIU's view, Mr. Lounsberry's reason for rejecting the current base gas adjustment, that AmerenIP should have identified the valve failure more swiftly, is an unfair criticism of AmerenIP's approach to identifying and correcting system issues. Mr. Lounsberry's criticisms of the operation of Hillsboro relate to events that took place prior to 2004. AIU insists that since 2004, AmerenIP has undertaken a number of steps to address these events. AmerenIP says it only discovered the leaking valve after the ultrasonic meter was installed, and AmerenIP compared its measurements with the existing master metering total withdrawal volumes. AmerenIP claims the leak was too small to be detected on the orifice recording chart or register on the station control system and noise through the leaking valve was not observed because of noise generated by the flow control valve down stream of the leaking valve masked any noise from the run change valve. AmerenIP also asserts that the annual maintenance performed on the valve indicated that the pneumatic operator rotated full open and back to full closed position each fall prior to withdrawal season. AmerenIP maintains that it had no reason to suspect that gas was by-passing the closed run changer valve until it compared the volume through the ultrasonic meter placed into service in January 2007.

Mr. Lounsberry asserts, however, that the past problems at Hillsboro are still relevant to this proceeding because he believes they relate to the issue of the discovery of the leaking valve problem in 2000. Mr. Lounsberry believes that AmerenIP should have discovered the leak before 2007, given the focus on issues at Hillsboro in 2004, and that AmerenIP's failure to review or discover that problem at that time is a reflection on how AmerenIP operated its storage fields during the time period. AIU believes this concern is mistaken. AIU states that AmerenIP made annual checks on the valve in question, but the purpose of these checks was to verify that the valve opened and closed at the appropriate differential pressure signals across the primary orifice run. Given the nature of the leak, AIU insists that it is unlikely the leak could have been discovered sooner, even during the investigations of issues at Hillsboro in 2004. AIU says AmerenIP personnel made no observations that gas was leaking from the valve when it was in the closed position until after the ultrasonic meter was installed and a difference was observed in the calculated volumes. In AIU's view, the failure to find the leak was not related to problems at Hillsboro, and the fact that there were past investigations does not mean the leak would have been found any sooner. AIU also maintains that AmerenIP would have had to discover the leak before April of 2004 to have made any difference in the adjustment sought in this proceeding. AIU says the estimated errors using AmerenIP's method did not affect the base gas values after April of 2004.

According to AIU, Mr. Lounsberry's suggestion that AmerenIP could have identified the valve leak through a "block and bleed" test is unfounded. AIU says the valve manufacturer's manual makes no mention of performing the procedure in order to verify the valve seats are seating properly; the manual does not mention this is a procedure that should be performed as ongoing maintenance of the valve; and the

procedure is not a common practice to perform. AIU contends the suggestion that AmerenIP should have performed this procedure reflects the benefit of hindsight, but AmerenIP had no reason to discover the leak prior to the installation of the ultrasonic meter. AIU adds that the consultant (Peterson) who performed the comprehensive 1999 metering study at Hillsboro did not suggest conducting such a test, which further demonstrates that this is not a common practice.

b. Staff's Position

Mr. Lounsberry opposes AIU's attempt to increase the base gas inventory value at the Hillsboro field by \$2,841,000. He has four reasons for disputing AIU's request. First, Mr. Lounsberry does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Second, he determines that AIU had inadequate support for the assigned value. Third, Mr. Lounsberry questions the validity of certain assumptions that AIU made as part of the calculation. Finally, he notes that given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro field, AmerenIP should have, as part of its overall investigation of the various problems it has experienced at Hillsboro, conducted a review of the integrity of the valve at a much sooner date and, as such, AmerenIP should have never found itself in this position.

AIU notes that as a result of new metering installed at Hillsboro storage field in 2007, AmerenIP discovered a discrepancy between the new metering and the original metering used to measure the volume of gas withdrawn from the Hillsboro field. AmerenIP conducted a series of tests that demonstrated there was a leak in the valve that separated the primary and secondary metering runs in the original metering set that measured gas flowing to the south of the Hillsboro field. AmerenIP claimed that this leaking valve allowed gas to pass undetected and unmeasured through the secondary metering run. AmerenIP selected the time period of 2000 to 2007 to reflect the measurement error.

Staff says AmerenIP's assumed timing for this metering error impacts the recoverable base gas valuation in 2001 to 2004 because it assumed this metering error occurred in addition to the metering error that was at issue in last rate case, Docket No. 04-0476. AmerenIP contends that both errors understated the withdrawals from the Hillsboro field, meaning that it had withdrawn gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes and had unknowingly withdrawn gas from its recoverable base gas inventory.

Mr. Lounsberry takes issue with AmerenIP's logic in selecting the starting date for the valve leak. In particular, he notes that AmerenIP assumed the leak existed for the period 2000-2007. Staff says AmerenIP's selection of that time period was based upon the fact that the valve was rebuilt in 1993 and the leak was discovered in 2007. Since the exact date of the leakage could not be determined by AmerenIP, Staff says it decided to go back to half the amount of time since the valve was installed. Staff believes that AmerenIP's decision regarding the timing of the valve leak was pure

speculation and is not sufficient basis to support the just and reasonable threshold for AmerenIP's request to increase the recoverable base gas costs at Hillsboro.

Mr. Lounsberry also expresses a concern regarding the lack of support that AmerenIP had for the volumes it calculated. Specifically, he notes two distinct concerns. First, AmerenIP's inconsistent operation of the Hillsboro storage field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. Second, AIU's current proposal is at odds with the information it provided in the prior rate case regarding the shortfall that existed at the Hillsboro field as of November 30, 2003, as detailed in the 2004 Hillsboro Report.

Staff asserts that AmerenIP's inconsistent operation of the Hillsboro field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. This viewpoint, Staff claims, was also shared by AmerenIP personnel in a November 20, 2006, report noting that in September 2004 AmerenIP had just completed a 2.2 Bcf addition to Hillsboro's inventory that completed AmerenIP's 3-year replacement (2003-2005) of the 5.8 Bcf inventory shortfall that IP found at the Hillsboro field in 2003. According to Staff, this report indicated that, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. Staff says AmerenIP personnel estimated that after 3 years of cycling the reservoir at a constant working gas volume, the reservoir would stabilize and the hysteresis curve will be helpful in quantifying gas loss volumes.

Mr. Lounsberry states that his understanding of this report was to represent that AmerenIP had no reliable support for adding any gas to the Hillsboro field because the field's reservoir information changed too frequently to be used to determine any values. Staff claims this also means that AIU's request is speculative and that it can not support the just and reasonableness of its proposal. In response to Mr. Lounsberry's concerns, AIU notes that AmerenIP used pressure and volume data to support the measurement error calculation and that it considered this data as sufficient to support the adjustment. AIU also notes that while Staff had previously questioned the methodology and conclusions on reservoir engineering studies in many previous AmerenIP cases, Staff never questioned the validity of the wellhead pressure measurement that it claims supports its request.

Aside from its previous discussion regarding the lack of reliable reservoir data, Mr. Lounsberry provided two additional reasons to dispute AIU's statements. First, while AIU's statement that Staff never disputed AIU's use or calculation of wellhead pressure measurement in prior cases is accurate, Staff did question AmerenIP's methodology and conclusions on reservoir engineering studies in those cases. Staff says the fact that AmerenIP, in the prior cases, did not rely solely upon the wellhead pressure measurement information to support its position suggests the other methodologies that AmerenIP employed in those proceedings were deemed by it to be superior to the calculations that AmerenIP provided in the instant proceeding that consider only one measure, wellhead pressure.

Second, Mr. Lounsberry understands that there are many methods available to AmerenIP to determine if a particular storage field has an inventory shortfall. Staff says a comprehensive review should be done to support an inventory shortfall; reliance should not just be placed on one measure whose information may or may not be consistent with other measures available to the utility. Aside from Mr. Lounsberry's concern regarding AmerenIP's calculations, AmerenIP also notes that it intends to conduct a detailed reservoir engineering study after the end of the 2008 injection season. AmerenIP indicates that this study was not performed in 2005 because it was of the opinion that there was insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate.

Mr. Lounsberry does not dispute AmerenIP's need to conduct the study, but believes that AmerenIP's statement that there is insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate is contrary to its claim that AmerenIP has valid support for the addition of about 1.1 Bcf of gas that would increase the base gas valuation of Hillsboro by \$2,841,000. Staff argues that the information is either available or it is not; AIU can not have it both ways. Mr. Lounsberry believes that AmerenIP does not currently have any reliable information to support the 1.1 Bcf addition.

Mr. Lounsberry expresses concern that AmerenIP had to make a number of assumptions when it calculated the measurement error volumes associated with the leaking valve at the Hillsboro field. He also asserts that AmerenIP's situation does not lend itself to provide a good basis to extrapolate out the measurement errors it found over a 7-year period. In particular, Mr. Lounsberry identified 5 areas of concern: valve leakage could have worsened over time; other errors could have existed; a 2.75% error existed even when valve was fully open; using one month to extrapolate out 7 years; and all meters in series show some difference in readings.

Mr. Lounsberry expresses concern that AmerenIP assumed the correction values it calculated could be applied for the whole period that AmerenIP estimates the measurement error took place. Staff asserts that it is possible that the valve leak worsened over time, meaning that AmerenIP's calculation overstates the initial volumes that were not measured. AIU's response to this concern is that it had no indication that the leak worsened over time. AIU also notes that it would be difficult to identify when such worsening of the leak would occur or at what rate the worsening would occur. Staff agrees that given the lack of data to support when the valve leak started or for how long the leak existed, it would be virtually impossible for AmerenIP to determine if or when such worsening of the valve leak would occur or at what rate the worsening would occur. Staff claims AIU has not stopped to consider the reasonableness of its assumption regarding the valve leak. Staff asserts that AmerenIP simply found a valve leak and then blindly assigned it to the time period that AmerenIP assumed the error occurred.

According to Staff, AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. Staff suggests that on an orifice meter, there are multiple items that can cause error, such as a pressure or temperature probe that is out of calibration. Staff contends it is not clear if AmerenIP eliminated all of the potential causes of measurement error when it performed its review. Staff says that if AmerenIP did not eliminate all potential causes for the error, then it could have under or overstated its measurement error estimate. AIU responds that, while it can not determine that —all of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP believes the leaking valves or the orifice plate were the dominate sources for the observed errors. AmerenIP also indicated that the pressure and temperature used for the orifice measurement relative to the measurements used for the ultrasonic meters would decrease the volumetric differences between the orifice measurement and the ultrasonic measured values.

Staff says that AIU's reference to the decrease in volumetric differences between orifice measurement and ultrasonic measurement due to the pressure and temperature variances between the two metering sets confirms Staff's point. Staff does not know the exact time period AmerenIP reviewed to make its statement, but the basic concept is that, depending on the frequency that AmerenIP calibrated its temperature and pressure probes and how much variance those probes could develop, the measurement calculation will differ over time, creating a situation where the volume differences either decreased or increased. Staff argues that given AmerenIP's decision to extrapolate out the measurement impact it calculated over a 7-year period, any variance in measurement can be significant and it does not appear that AmerenIP attempted to account or identify the reasons for those errors.

Staff also expresses concern over the fact that AmerenIP calculated an error of 2.75% even when the valve was fully open. Staff says that since AmerenIP claimed the reason for the measurement error was due to the leaking valve, it would not expect a fully open valve with a leaking seal to create a measurement error of that magnitude. Staff's understanding of AmerenIP's explanation for the measurement error is that some quantity of gas passed through the valve that the secondary metering run could not measure because the amount was too small for the meter to pick up. Staff claims that once the valve is fully open, the secondary metering run is measuring a considerable amount of gas that should account for all gas volumes whether the valve is leaking or not. Staff contends that the measurement error under that circumstance should be negligible, not a significant amount like 2.75%.

AIU responds by indicating that the analysis of the 2.75% error was determined from actual daily flows from both of the orifice runs. AmerenIP also indicates that based on an hourly test flow rate of 1600 Mcf/hour, with both primary and secondary metering runs open, the accumulated error percentage was 2.246% and not negligible. Therefore, AmerenIP believe the assumption that for flows exceeding 35,000 Mcf/day there is a 2.75% error is comparable to the error shown for just one point in time.

Staff does not dispute AmerenIP's calculation of the error percentage, the fact that an error exists lends support to its second concern that AmerenIP had not identified all of the causes of the measurement error. According to Staff, a 2.75% variance between two sets of meters is considerable and AmerenIP should have attempted to determine the cause of this error beyond the general conclusion that the error is a result of the valve leak. AIU responds by noting that when it was calculating its measurement errors, it was disrupting the manner in which the Hillsboro field normally operated. AIU states that AmerenIP had identified the cause of the measurement error and it would be unreasonable to disrupt the dispatch function further and tie up operators for long periods of time to determine the source of errors beyond what was performed. Staff also does not dispute that AmerenIP was likely disrupting the manner that the Hillsboro storage field operated when it was conducting various measurement tests. Staff maintains, however, that AmerenIP found an almost 3% error in a situation where the error reading should have been negligible and AmerenIP did not bother to investigate the cause of the problem further.

Staff also argues that it is not possible that all of the circumstances occurring for that one month were exactly the same for all of the months over the prior 7 years. In other words, Staff claims AmerenIP had a snapshot of what occurred, but has no way to determine if the circumstances that occurred during that month were identical to the circumstances for the prior 7 years. AIU responds that the selected review period represented the best available information regarding the measurement error. Since it was the best information available, AIU claims that it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

Staff states that, in theory, two meters placed in series would show no variance; however, the reality is that all meters have some variance between each other. Staff indicates this could occur because no meter is perfect and meter manufacturers do not guarantee absolute accuracy with their meters. Staff says there is usually an accuracy range provided, such as plus or minus 1%. Therefore, Staff indicates that two meters in series will likely not correlate directly to each other. As a result, Staff expressed a concern that a small portion of AmerenIP's correction it is attempting to fix could, in reality, not be a measurement error.

In its Reply Brief, Staff notes that AmerenIP argues that it is not required to use any particular type of study to demonstrate prudence, and that no one has challenged the two forms of input data that AmerenIP is using to support measurement error correction, namely pressure and inventory. According to Staff, AmerenIP indicates that, contrary to Staff's concern that AmerenIP could have used superior methodologies, it used valid reservoir engineering techniques to determine gas loss. Staff disagrees. Staff contends it has not directed AmerenIP to make use of any specific type of analysis to support the adjustments. Staff claims it pointed out that AmerenIP had used in its prior rate case a reservoir simulator model that its witness from that proceeding indicated was superior to any static method of predicting reservoir behavior. Staff expresses concern that, given the time and money spent on developing this model, Staff would have expected AmerenIP to make use of the model had it been available.

Staff says that contrary to AIU's claims, this is not a directive from Staff to make use of a specific analysis. Instead, Staff indicates that AmerenIP's analysis failed to support its request. Staff does not agree that the reservoir engineering techniques AmerenIP used were valid under its current circumstances.

c. Commission Conclusion

AIU proposes the addition of \$2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims the addition is necessary to account for base gas lost through a valve leak and is necessary to maintain the deliverability of the Hillsboro Storage Field. AIU argues that AmerenIP used the best techniques available to estimate the lost gas and that it should be allowed to include the base gas in rate base.

Staff objects to AIU's proposal to include the additional base gas in rate base. Staff does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Staff contends that AIU has not adequately supported the amount it seeks to include in rate base. Staff questions the validity of certain assumptions that AIU made as part of the calculation. Given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro storage field, Staff asserts that as part of its overall investigation of the problems at Hillsboro, AmerenIP should have conducted a review of the integrity of the valve at an earlier date.

The Commission observes that this issue is strikingly similar to the issue decided immediately above. In both instances, AIU asserts that there has been lost base gas, has estimated the volume of missing gas, and requests authorization to include the additional base gas in rate base. Also in both instances, Mr. Lounsberry objects to AIU's request. Mr. Lounsberry again insists, among other things, that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost base gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AmerenIP failed to adequately demonstrate that its estimate of the lost base gas is reasonable. As a result, the Commission adopts Staff's recommendation and AIU's request to include the additional base gas in rate base is denied. In the Commission's view, this decision regarding lost gas at Hillsboro is consistent with, and is required by, the appellate court decision discussed earlier in this Order.

D. Approved Rate Bases

Based on the determinations made above, the rate bases for AIU's respective service territories are approved as shown below and in the Appendices attached hereto.

	AmerenCILCO	AmerenCIPS	AmerenIP
Electric	\$240,625,000	\$443,743,000	\$1,254,459,000
Gas	\$183,734,000	\$181,735,000	\$518,857,000

V. OPERATING REVENUES AND EXPENSES

A. Introduction

Schedules showing the operating revenues, expenses, and income at present and recommended rates for the test year ending December 31, 2006, were presented by AIU and Staff.

B. Resolved Issues

1. Annualized Labor and Pro Forma Wage Increases

Staff witness Ebrey recommends adjusting annualized labor expense to reflect a 3% wage increase effective July 1, 2007, based on her assessment of actual wage increases approved in December 2007. AIU agrees with this adjustment.

Ms. Ebrey also recommends disallowing wage increases for management employees projected for April 1, 2008. AIU responds that the wages already increased to slightly beyond the estimated levels as of the time of the filing of rebuttal testimony, thus the increases are known and measurable. In its rebuttal testimony, Staff accepts the AIU proposed rebuttal labor adjustment for management employees in all six rate cases. The Commission finds Staff's proposed adjustment to increase labor expense to reflect the July 1, 2007, wage increase reasonable and is hereby adopted. The Commission also finds AIU's proposal to reflect the April 1, 2008, management wage increase reasonable and is hereby adopted.

2. Injuries and Damages Expense

Rather accepting AIU's proposal for calculating injuries and damages expenses, Staff proposes using a five year average in calculating the expenses for AmerenCILCO's, AmerenCIPS', and AmerenIP's gas operations. For these five utility operations, AIU does not object to Staff's proposed methodology. The Commission finds this approach to be reasonable and it is hereby approved for the five utility operations identified. The issue of how injuries and damages expenses should be calculated for AmerenIP's electric operations is address later in this Order.

3. Employee Benefits Expense

Staff proposes an adjustment to AIU's Employee Benefits Expense. For purposes of this proceeding, AIU accepts Staff's proposed adjustment to Employee Benefits Expense. The Commission finds Staff's proposed adjustment to the employee benefits expense reasonable and it is hereby approved.

4. Reliability Audit

With regard to the Liberty reliability audit performed for AIU, Staff witness Ebrey proposes to only allow the maximum estimated price of Liberty, \$2,897,880, and the actual rental of office space for 12 months per the lease agreement of \$29,290, allocated to each electric utility consistent with AIU's proposal. AIU accepts Staff's proposed adjustment. The Commission finds Staff's proposed adjustment to the reliability audit expense reasonable and it is hereby approved.

5. Storm Costs

Staff witness Everson recommended use of a separate subaccount to track costs associated with storm restoration. After reviewing AIU's responsive testimony, Ms. Everson withdrew her recommendation. The Commission finds that there is no longer a contested issue related to storm costs and the Commission takes no action.

6. Interest on Customer Deposits

Staff witness Everson proposes using a 3.5% rate as the interest rate on customer deposits, which was accepted by AIU. AIU believes the adjustment should be reflected as an adjustment to Customer Accounts Expense, to which Staff does not object. The Commission finds the proposed treatment of customer deposits to which AIU and Staff agree to be reasonable and it is hereby approved.

7. Accounts 856, 863, 874, and 887

In direct testimony, Staff witness Lounsberry raises concerns regarding Accounts 856, 863, 874, and 887. In its rebuttal, AIU explains the nature or circumstances surrounding the costs (in particular, that costs shift between the AIU transportation and distribution Operations and Maintenance ("O&M") accounts from year to year). Mr. Lounsberry found AIU's explanation acceptable and withdrew his proposed adjustment.

8. Advertising Expense

Staff proposes an adjustment to AIU's proposed level of Advertising Expenses, which AIU accepts. The Commission finds Staff's proposed adjustment to advertising expenses to be reasonable and it is hereby approved.

9. Industry Association Dues Expense

Staff proposes and adjustment AIU's electric utilities' industry association dues, which AIU accepts. The Commission finds Staff's proposed adjustment to AIU's electric industry association dues expense reasonable and it is hereby approved.

10. Vegetation Management/Tree Trimming

In response to AG/CUB witness Effron's direct testimony, AmerenIP agrees that its tree trimming expenses should be reduced by \$1,932,000. Although Mr. Effron originally proposed an adjustment to AmerenCIPS' pro forma tree trimming expenses, after reviewing Mr. Stafford's rebuttal testimony explaining why no such adjustment was necessary, Mr. Effron withdrew his proposed adjustment. The Commission finds that the agreed adjustment to AmerenIP's tree trimming expense is reasonable it is hereby approved.

11. Midwest Independent System Operator Expenses

AmerenIP agrees to the proposal to eliminate from its delivery service revenue requirement \$1,037,000 of payments to the Midwest Independent System Operator, which AmerenIP charged to Account 928 "Regulatory Commission Expenses" in 2006. The Commission finds the proposal to adjust Account 928 for AmerenIP to be reasonable and it is hereby approved.

12. Retired Production Worker Pension and Medical

In his direct testimony, Staff witness Lazare expresses concern about whether pension and health care costs for AIU retirees who worked at production facilities that have since been divested from AIU should be included in test year A&G expenses. AIU accepts Staff's proposed adjustments. The Commission finds Staff's proposed adjustment related to the retired production worker pension and medical expense to be reasonable and it is hereby approved.

13. Test Year NESC Violation Correction Costs

In response to Staff's concerns regarding the costs to correct National Electrical Safety Code ("NESC") issues during the test year, AIU agrees to track the costs of repair or replacement of identified down guy, overhead guy, and double-cross arms at affected railroad or interstate highways. AIU agrees to replace those railroad or interstate highway crossings that have only a single cross-arm, but under new NESC standards should now have a double-cross arm. Additionally, AIU agrees to bear all 2006 test year costs associated with the remediation of NESC violations. The Commission finds it appropriate for AIU to track the costs of repair or replacement of facilities that were originally constructed in violation of NESC to be reasonable. Additionally, the Commission agrees that AIU should not recover from ratepayers the costs incurred during the test year for these types of activities.

C. Contested Issues

1. AMS Charges

a. AIU's Position

AIU argues that accepting Staff's proposed adjustment of \$48.3 million representing AMS charges would pose a significant threat to AIU's financial health and that it is entitled to recover the charges AMS assesses on AIU for essential utility services. AIU alleges that Staff's adjustment arises from its invention of a new allocator that Staff applies to the total AMS charges assessed on all Ameren subsidiaries. AIU submits that Staff's allocator is based on an assumption that has never been tested, proven, or used in any jurisdiction and the allocator presupposes that all subsidiaries will consume services from a common service company in direct proportion to their size, as measured by the simple arithmetic average of three metrics: total assets, total employees and non-fuel O&M. AIU avers that should the Commission accept this adjustment, AIU will under-recover its costs by \$48 million. Were this to happen, AIU claims it would be forced to make cuts in service in order to maintain its financial condition.

AIU points out that in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission directed AIU to provide, in its next delivery service case, a study regarding the services and related costs that AMS provides to AIU. AIU submits that in compliance with the Commission's directive, it hired a consulting firm, Concentric, to prepare a study of the services and related costs that AMS provides to AIU. AIU says the Concentric study benchmarks the costs of specific services provided by AMS to AIU. AIU notes that the services studied include finance, information technology, human resources, procurement, legal, government affairs, and corporate communications, which account for approximately 60% of total AMS expenses charged to AIU. AIU states that for each of the services provided by AMS, the total cost of providing the service was compared to both other utilities and to non-utility companies. According to AIU, AMS costs for services compared favorably to the peer companies.

AIU explains that during the review of AMS costs allocated to AIU, Concentric employed a cost causation standard to assess the reasonableness of the allocated costs, and under cost causation principles, the standard of reasonableness was whether the costs allocated to each of the individual utilities was representative of the benefits realized by each company. AIU further explains that AMS costs are recorded in various SRs. Each SR relates to a specific scope of work by an organizational unit within AMS. AIU notes that when created, the SR must consist of a project name, a description of the work to be performed, and the allocation factor to be used to distribute the costs assigned to each SR. The appropriate allocation factor is determined from the list of available allocators set forth in the General Services Agreement ("GSA"). The SR is signed off on by representatives of each Ameren subsidiary which will benefit from the work performed and a representative of AMS.

AIU argues that it has complied with the Commission's directive in the last proceeding, that it has submitted substantial evidence demonstrating that its A&G costs in general, and AMS charges in particular, are reasonable, consistent with those incurred by comparable entities in the market, and should be approved as proposed.

b. Staff's Position

Staff argues AIU proposes a disproportionate allocation of AMS costs to AIU without providing a reasonable explanation or adequate support. According to Staff, there are systematic problems with the allocation of AMS costs that not only support Staff's proposed \$48.3 million reduction in these costs, but further call into question the full amount that AIU proposes to recover from ratepayers. Staff submits that its proposed adjustment of \$48.3 million would make the allocation of AMS charges to AIU consistent with the relative size of each company.

Staff points out that AMS costs are a significant portion of test year costs. Staff notes that AIU seeks to recover a total of \$213.7 million in AMS costs from ratepayers for the test year. Staff further notes that the Commission has expressed its ongoing concern about the recovery of these costs from ratepayers, and Staff submits that AIU has yet to satisfactorily address these concerns. Staff further opines that a review of the evidence in this case shows that there are fundamental problems with the way AMS costs are allocated to AIU.

Staff argues that the first step in developing its adjustment is to determine what would be an appropriate allocation of AMS costs to AIU based on the relative size of each company. According to Staff, there are three measures to determine the relative size of a company: assets, non-fuel O&M, and number of employees. Staff notes that assets are the investments on which a company seeks to earn a return. Staff contends the level of assets is an important determinant of their level of business success. Staff notes that non-fuel O&M reflects expenses incurred to operate a company, and Staff submits that the levels of these costs provide an indicator of the relative costs of operating a company. As to number of employees, Staff suggests a larger company will entail more activity and require more employees to ensure that tasks are performed.

Staff witness Lazare found that AIU accounts for 34.0% of assets; 33.9% of employees; and 36.8% of non-fuel O&M expenses for Ameren as a whole. Staff submits that with no specific evidence to indicate that any of these measures is more relevant than any other, the simple average of these percentages is used to find that AIU constitutes 34.9% of Ameren on a size basis. Since AMS charged a total of \$473.6 million to all Ameren subsidiaries in 2006, Staff suggests that the share that AIU should receive based on its size is 34.9% of that total or \$165.4 million. Staff further argues that since AIU proposes to allocate \$213.7 million of AMS costs to AIU for the test year, an adjustment of \$48.3 million to AMS costs allocated to AIU is appropriate.

Staff points out that AIU has a responsibility in this case to demonstrate that it received a reasonable share of AMS costs, particularly in light of the Commission's

concern in Docket Nos. 06-0070/06-00071/06-0072 (Cons.) about the allocation relative to other Ameren subsidiaries. However, Staff suggests that AIU failed to explain why it receives a disproportionate share of these costs relative to its size. Therefore, Mr. Lazare proposes an adjustment to remove the "excess" share of AMS costs.

Staff argues Mr. Lazare's proposed adjustment represents a conservative reduction in AIU's proposed revenue requirement. Staff states further that the evidence reveals fundamental problems with the SRs, which are the building blocks for the allocation of AMS costs among Ameren subsidiaries. The process by which these SRs are allocated to AIU, Staff argues, is riddled with errors, and the resulting allocations of AMS costs as a whole are called into question.

Staff complains that based upon its review, AIU witness Adams identified only three SRs that were inaccurately recorded, resulting in an under allocation of \$23,869 to AIU by AMS. Staff is not comfortable with Mr. Adams' conclusion that the services described and allocations for each SR are reasonable. Staff suggests that the focus of this case should be on AIU's failure to support its disproportionate allocation of AMS costs. Staff posits that should AIU succeed in changing the subject to focus on a small number of SRs, AIU and other utilities will be encouraged to provide even less support for their ratemaking proposals in the future.

In addition, Staff disagrees with AIU that its bench mark study justifies AMS costs allocated to AIU. Staff argues the study failed to answer a basic issue raised by the Commission in its Order on Rehearing in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission in that proceeding stated that there was insufficient evidence to indicate that AIU received a reasonable allocation of AMS costs relative to other Ameren affiliates. This statement emphasizes, according to Staff, the need to examine AMS costs for all Ameren companies, not just those directly regulated by the Commission. Staff suggests that the Commission appropriately recognized that the fairness of the allocation of common AMS costs to one group of Ameren companies can only be assessed when comparable information is provided on the allocation received by others. Staff notes that AMS costs are shared by all Ameren subsidiaries, and that it is essential for Ameren to show that the allocations to AIU are reasonable compared with other Ameren subsidiaries.

According to Staff, the Commission must assess the reasonableness of all costs passed along to AIU ratepayers, including AMS costs. Staff suggests however, that the study performed by Mr. Adams fails to satisfy this requirement. Staff notes that while Mr. Adams identifies five findings he made from the study in his rebuttal testimony, none of these findings directly discuss how AMS costs are allocated to other Ameren subsidiaries. Staff suggests further that the study only examined the A&G component of AMS costs, while AIU is additionally requesting recovery of AMS charges that are outside the A&G area.

c. Commission Conclusion

As the parties are aware, the Commission takes seriously its obligation to assure that affiliate costs are not improperly passed along to utility ratepayers. AIU and AMS operate under the GSA previously approved by the Commission. The GSA calls for direct assignment of AMS costs where possible. In addition, the GSA contains numerous allocation factors that are to be used when costs can not be directly assigned. While AIU is not necessarily entitled to recover from ratepayers all AMS costs allocated pursuant to the GSA, the GSA is intended to assist the Commission in ensuring that AIU and ratepayers are not assessed improper costs by affiliates.

Rather than rely upon direct assignment and the numerous allocation factors contained in the GSA, Staff assumes that all AMS costs should be allocated among affiliated entities on the basis of their relative size. That assumption is inconsistent with the GSA approved by the Commission and, in the Commission's view, is not a reasonable assumption. Under Staff's proposal, for example, assuming that AMS provides services to AIU to prepare and litigate a rate case, 65% of such costs would be allocated to unregulated affiliates. Unfortunately, it is easy for the Commission to envision numerous situations where AMS costs would not properly be allocated among Ameren companies based upon the relative size of the companies. The Commission can envision situations where costs would be improperly allocated to AIU as well as situations where costs would be improperly allocated to unregulated affiliates. The Commission concludes that Staff's single allocator is too simplistic and does not produce reasonable or appropriate results.

While not perfect, the Commission finds the Concentric study of AMS charges to be helpful. The Commission believes that the testimony of Mr. Adams and the Concentric study demonstrate that test year level of AMS costs assessed to AIU are reasonable. In summary, the Commission concludes that Staff's proposal should be rejected and that the record supports a finding that the AMS costs assigned to AIU are reasonable and should be included in operating expenses.

In its Brief on Exceptions, Staff complains that the conclusion in the Proposed Order did not specifically address each and every alleged flaw it identified in AIU's AMS cost analysis. To be clear, the Commission considered each aspect of Staff's arguments, and the Commission does not believe that AIU's evidence is perfect. The Commission concludes, however, that despite any flaws in the evidence presented by AIU, it is superior to Staff's proposal for establishing the amount of AMS costs that should be reflected in rates. Section 10-103 of the Act mandates that the Commission make its decision based exclusively upon the record. The Commission finds Staff's proposal unworkable and unreasonable, thus, the record supports a conclusion that the test year level of AMS costs assessed to AIU is reasonable.

In its Brief on Exceptions, Staff also claims that the conclusion in the proposed order is inconsistent with the decision in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission notes, however, that in the previous AIU rate cases, the

basis of Staff's proposed disallowance of AMS costs was not an allocator based upon the relative sizes of AIU and other affiliates. In that case, the Commission identified specific costs that were not adequately substantiated. Here, the record does not support a finding that Staff's proposed allocation factor is reasonable. Of the alternatives available in the record, the Commission finds that the record supports a conclusion that Staff's proposed disallowance must be rejected. This does not mean that in future cases Staff can not propose disallowance of AMS costs if it can develop an appropriate basis.

2. Incentive Compensation Costs

a. AIU's Position

AIU proposes to recover a total of \$5,238,000 in incentive compensation expenses in rates. AIU witness Bauer asserts that incentive compensation is a common and necessary component of the total compensation package for employees in the electric and gas utility industry. Over the next decade, according to AIU, the electric and gas utility industry is expecting a substantial number of employee retirements, thus resulting in increased competition for talent. AIU argues that in order to attract and retain qualified employees, and to motivate employees to perform to the best of their ability, AIU must ensure that its total compensation package is competitive. According to AIU, a competent, stable, focused and motivated workforce is critical to providing excellent service to its customers. AIU believes that by using both base and incentive pay, it is able to limit its fixed costs (base pay), yet still reward employee performance (incentive pay).

According to AIU, its incentive compensation plan costs are designed in a manner consistent with market practice. Additionally, AIU argues its incentive plans require achievement of operational performance, thus the plans are designed in a prudent and reasonable manner. AIU claims no party has contested the prudence or reasonableness of the AIU's overall level of total employee compensation. Therefore, AIU believes its proposal to pass the costs along to ratepayers should be accepted. AIU argues that the incentive compensation plan benefits the utility's customers and the costs should be recoverable in rates.

According to AIU, it provided evidence of operational and individual goals that can be considered and paid independently of financial goals under the plans. For the 2006 test year, AIU argues key performance indicators were associated with incentive payouts under the plans, such as O&M budget compliance (weighted 20%), capital budget compliance (weighted 20%), safety (weighted 25%), gas O&M (weighted 10%), customer service (weighted 10%); and reliability (weighted 15%). AIU claims each of these metrics benefits AIU's customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations.

AIU asserts that it presented evidence providing —financial-based” and —performance-based” percentage breakdown amounts for the recently modified 2008

incentive compensation plans, which are currently in effect and will be in effect when the Commission approves rates resulting from this case. According to AIU, the 2008 plans focus employees on operational metrics and provide a link between pay and performance.

Ms. Bauer explained that there are some similarities between the 2008 plans and the 2006 plans. AIU says the most significant difference between the 2008 and 2006 incentive plans is that payouts for most of the current plans, with the exception of the Executive Incentive Plan for Officers, are no longer funded only if Ameren meets earnings per share ("EPS") targets. Instead, AIU claims performance on incentive key performance indicators (e.g., operational goals) determines whether or not awards will be available under the plan.

AIU argues that even if the Commission does not consider the modified plans, the incentive compensation plans in effect during 2006 are based on the achievement of operational goals that primarily benefit customers; therefore, incentive compensation expense would be properly recoverable regardless of whether the Commission considers the modified plans. AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance. AIU further argues that it has presented the same type of evidence provided in the Docket No. 03-0403 proceeding, where the Commission approved recovery of incentive compensation expense.

AIU contends that Staff's arguments fail to recognize that a high percentage of the expected payouts under the 2008 plans are not tied to financial performance. AIU also disagrees with Staff's argument that a disallowance is appropriate because AIU's incentive compensation plans could be discontinued. According to AIU, incentive compensation is a critical component of AIU's total compensation package. AIU says most companies, including AIU, reserve the right to change, modify, add, or eliminate rewards programs as needed.

Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

b. Staff's Position

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that payouts under AIU's incentive compensation plans are dependent upon financial goals of AIU that primarily benefit shareholders. Staff also expressed a concern that ratepayers would provide funding even when no costs were incurred by AIU because the incentive compensation plan goals were not met. Staff contends that the plans are discretionary and may be discontinued at any time. Staff also believes that prior Commission practice supports

the disallowance of AIU's incentive compensation costs from operating expenses. Staff notes that the Commission considered the same incentive compensation plans in AIU's last rate case, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Although certain financial thresholds have changed in this case, Staff states that the majority of the arguments provided by AIU are nothing more than a replay of the same arguments offered in its last rate case, which the Commission rejected.

Staff points out that AIU indicates that certain revisions were made to its incentive compensation plans effective January 1, 2008, and provided a schedule showing which of the 2006 costs would have been unrelated to financial targets had the revised plans been in place for that plan year. According to Staff, this presentation is flawed for two reasons. First, Staff argues that nothing has been paid out under the revised plans, which will not be considered until the Spring of 2009; thus, Staff believes the impact of the January 2008 revisions is not yet known and measurable. Second, Staff says AIU did not propose an adjustment that limited incentive compensation expense to the costs unrelated to financial targets.

Staff rejects AIU's argument that since the modified plans are those that will be used to determine incentive compensation expense during the period in which rates established in this case will be in effect, it is appropriate to consider the terms of the modified plans. Staff claims this argument is in direct conflict with AIU's position regarding the Public Utility Fund Base Maintenance Contribution. Staff states that in that instance, AIU argues that since the impact of the change in law will not occur until January 2009, it is not appropriate to consider the change in determining the revenue requirements for these cases. Finally, Staff argues, in prior cases the Commission has made clear that it expects utilities to provide detailed information as evidence of ratepayer benefit resulting from incentive compensation plans. Staff believes AIU has not provided this detailed information nor can the information be provided since AIU's revised plans have only been in place since January 2008. As such, Staff contends that the revised plans have not been in existence long enough to provide the type of evidence that must be considered. While AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance, Staff rejects this as detailed evidence the Commission requires. Thus, Staff recommends that the Commission approve its adjustment disallowing incentive compensation costs, a total of \$366,000 for AmerenCILCO's gas operations, \$567,000 for AmerenCILCO's electric operations, \$424,000 for AmerenCIPS' gas operations, \$958,000 for AmerenCIPS' electric operations, \$468,000 for AmerenIP's gas operations, and \$1,135,000 for AmerenIP's electric operations as provided in Schedule 13.07 for each utility.

c. AG's Position

The AG asserts that because AIU's incentive compensation plan results in benefits to shareholders instead of ratepayers, 100% of those program costs should be eliminated from pro forma test year O&M expenses. The AG points out that in more recent cases, the Commission has eliminated incentive compensation plan costs unless

the company can demonstrate that the goals employees are expected to achieve would benefit ratepayers, such as the improvement of service quality, reliability, public safety, reducing absenteeism, and cost containment. The AG states that incentive compensation based on financial goals such as maximizing profitability and growth, increasing EPS, or increasing return on equity is beneficial only to shareholders, and not properly recoverable from ratepayers.

According to the AG, in AIU's last electric rate case, the Commission found that AIU's incentive compensation funding measures all relied on EPS targets and disallowed the entire test year compensation from AIU's revenue requirements. In this case, it appears to the AG that all of the test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year operation and maintenance expenses. The AG says the effect of this adjustment is to reduce AmerenCILCO's electric expenses by \$521,000, AmerenCIPS' electric expenses by \$867,000, AmerenIP's electric expenses by \$1,027,000, AmerenCILCO's gas expenses by \$365,000, AmerenCIPS' gas expenses by \$424,000, and AmerenIP's gas expenses by \$468,000 as shown on AG/CUB Ex. 1.1, Schedule DJE-4, page 1.

d. CUB's Position

CUB points out that the Commission has disallowed incentive compensation from utilities' revenue requirements except where the utility has demonstrated that the incentive compensation plan provided a tangible, quantified benefit to ratepayers, by reducing expenses and creating greater efficiencies in operations. Therefore, to include any portion of incentive compensation costs in approved operating expenses, CUB says AIU must demonstrate that the plan confers upon ratepayers' specific dollar savings or other tangible benefits.

In the present cases, CUB argues AIU has not presented any such testimony demonstrating its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma operation and maintenance expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year. CUB contends that because shareholders are the primary beneficiaries of the attainment of AIU's financial goals in terms of increases to earnings and return on equity, it should be those shareholders, not customers, who bear the cost of the incentive compensation related to the achievement of such financial goals.

According to CUB, AIU did not present any evidence that funding measures have changed from the 2004 test year in Docket No. 06-0070/06-0071/06-0072 (Cons.) to the 2006 test year in the present cases. Therefore, CUB argues that it appears that all of the test year incentive compensation expense is still related to the attainment of financial goals. Accordingly, AG/CUB witness Effron proposes to eliminate 100% of the incentive compensation from pro forma test year operation and maintenance expenses.

e. IIEC's Position

IIEC proposes an adjustment to AIU's incentive compensation expense reducing the level of expense included in AIU's cost of service. IIEC asserts that the proposed adjustment should be made to the stakeholder group that benefits from the incentive target, and therefore should pay the related expense. According to IIEC witness Gorman, approximately 50% of the proposed incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets according to Mr. Gorman include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employees safety targets. IIEC asserts that AIU confirmed that its test year incentive compensation programs were identical to the programs for which costs were disallowed in AIU's most recent rate case. It was on this basis that Mr. Effron opined that the result in this case should not differ from the Commission's last decision on the same programs. IIEC says AIU's recent program revisions, made to better reflect past Commission decisions, will affect only post-test year incentive compensation plans and costs.

IIEC asserts that upon consideration of the testimony and arguments of Staff and AG/CUB favoring rejection of all incentive compensation costs, and although IIEC finds them compelling, if the Commission is not persuaded and does not disallow AIU's requested incentive compensation costs in their entirety, IIEC's proposes a ceiling for allowed incentive compensation costs. IIEC believes its proposal is consistent with the record evidence and protects ratepayers from those cost burdens that most clearly do not benefit customers.

f. Commission Conclusion

AIU proposes to recover the costs of its incentive compensation plans in rates. AIU argues its new 2008 incentive compensation plans require operational performance to be achieved before payments are made. According to AIU, its operational and individual goals are based on metrics that can be considered and paid independently of financial goals under the plans. AIU claims each of these metrics benefits AIU's customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations. Other portions of AIU's incentive compensation plans retain the EPS funding mechanism. Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that the incentive compensation plans are dependent upon financial goals of Ameren that primarily benefit shareholders. Staff

adds that ratepayers would provide funding even if no costs are incurred by AIU because the plan goals are not met. Staff states further that the plans are discretionary, may be discontinued at any time and that prior Commission practice supports the disallowance of incentive compensation. Staff also believes that AIU has not provided the detailed information necessary to conclude that ratepayers benefit from the plans. Nor, Staff continues, can such information be provided since AIU's revised plans have only been in place since January 2008. As a result, Staff contends the revised plans have not been in existence long enough to provide the type of evidence that must be considered.

The AG asserts that AIU's test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year O&M expenses.

CUB argues that AIU must demonstrate that the plan confers upon ratepayers specific dollars savings or other tangible benefits or the costs can not be reflected in rates. According to CUB, AIU did not present any such testimony demonstrating that its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma O&M expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year.

IIEC asserts that approximately 50% of the test year incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets, according to Mr. Gorman, include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employee safety targets.

The Commission is somewhat encouraged that AIU has begun to modify its incentive compensation plans in a manner that may allow it to recover at least a portion of the costs from ratepayers. The Commission is not opposed to the use of employee incentive compensation plans; however, the Commission maintains that before the costs of such plans will be imposed on ratepayers, a utility must demonstrate that the plans provide meaningful benefits to those ratepayers. Regarding AIU's 2008 incentive compensation plan, with the exception of the Executive Incentive Plan for Officers, AIU claims they are no longer funded only if Ameren meets EPS targets. Unfortunately, the record does not specifically identify the portions of the 2008 plan that are directly dependent upon Ameren meeting financial targets.

The record indicates that AIU has in place incentive compensation plans related to safety (weighted 25%), customer service (weighted 10%), and reliability (weighted 15%) that also do not appear to have payouts that are dependent upon Ameren meeting financial targets. In the Commission's view, it is reasonable to allow AIU to pass the cost of these portions of the incentive compensation plans on to customers. Thus, AIU will be allowed to include in operating expense 50% of the total cost of its incentive

compensation expense because the Commission believes that portion provides direct, meaningful benefits to ratepayers and payouts are not dependent upon meeting financial targets that are primarily beneficial to shareholders.

If during the period that the rates approved herein are in effect, however, the incentive compensation plans are revised such that financial goals of Ameren become the payment trigger for a greater portion of the plans, the Commission will not look favorably on incentive compensation expenses in AIU's next rate cases. The Commission is allowing AIU to recover 50% of its incentive compensation expenses with the understanding that at least 50% of the payments made thereunder will be based on performance or goals other than Ameren's financial goals.

3. Rate Case Expense

a. Legal Fees

i. AIU's Position

According to AIU, the requested amounts for legal expenses in this case are reasonable. AIU estimates legal expenses for this proceeding as \$1,162,000, of which \$605,000 was estimated to be incurred by the time hearings began. Through April 30, 2008, AIU asserts that it received invoices for approximately \$670,000 for legal expenses. Although rate case expenses were running above budget, AIU states that it is not proposing any upward adjustment to the requested level of rate case expense. AIU argues that the estimated and actual rate case expenses in this case are proving to be reasonable in comparison with actual and estimated costs in the previous rate case.

AIU claims that Staff's assertion that it received invoices ~~two~~ days prior to the evidentiary hearings," without enough time for Staff witness Ebrey to analyze the invoices contradicts Staff's own statements and testimony. AIU submits that Staff offered no record cites in support of this claim. To the contrary, AIU claims Ms. Ebrey testified at the evidentiary hearing that she had, in fact, reviewed the invoices, again, mentioning her ~~con~~cerns about a number of the items that appear on the invoices." (Tr. at 791-92) AIU says Ms. Ebrey did not testify, however, that she did not have enough time to review the invoices.

ii. Staff's Position

Staff proposes to limit the cost of legal fees to the amount actually supported by invoices, as AIU did not provide sufficient support for its requested level of legal fees and Staff could not determine the reasonableness of the estimate for those costs. According to Staff, the record in this case only reflects \$470,000 in questionable legal fees for rate case expense. Staff characterizes these costs as questionable since it did not receive sufficient detail to be able to analyze the costs until two days prior to the start of the evidentiary hearings. Since no investigation of the costs in question was possible, Staff recommends that the Commission should not allow those costs to be

recovered as rate case expense. In Staff's view, the Commission should only allow the costs for attorney's fees that AIU properly supported.

iii. Commission Conclusion

As the Commission understands it, AIU proposes to reflect in rates approximately \$194,000 in legal expenses from the law firm of Jones Day Reavis & Pogue for each utility's electric operations and each utility's gas operations. The Commission also understands that, in contrast, Staff proposes allowing \$44,000 for each utility for these costs. Staff proposes disallowing all prospective legal expenses for which invoices were not provided. Additionally, Staff suggests that some invoices provided by AIU were provided so late in the process that Staff was unable to adequately review them. Thus, Staff's proposed disallowance effectively disallows a portion of actual costs incurred for which invoices were provided.

The Commission is troubled by the Staff proposal. The proposal to allow recovery of only legal costs associated with those invoices that Staff has adequately reviewed puts AIU in a situation where it must incur costs but can not recover those costs from ratepayers. There is no question that to effectively pursue this rate increase request, AIU will continue to incur legal expenses after Staff files rebuttal testimony and even after the evidentiary hearings. Obviously, AIU can not produce invoices for Staff to review before the legal work is done. The proposal to disallow 100% of costs for which invoices for rate case legal work that were not adequately reviewed by Staff is fundamentally unfair. A more fair approach might be to propose disallowing the percentage of forecasted costs based upon the percentage of actual legal expenses that were found to be improperly incurred or billed. Other reasonable approaches might be to determine that legal expenses were overestimated by some amount or percentage, or that the legal expenses themselves were unreasonably high. Staff's proposal, however, would inevitably lead to costs that must be incurred but could not be recovered. This is particularly true when combined with Staff's position in this proceeding with respect to unamortized rate case expense, whereby only amounts previously approved by the Commission are eligible for recovery on a prospective basis. Staff's approach would be an unfair and unreasonable result. Based upon the record in this proceeding, the Commission hereby rejects Staff's proposal to disallow legal costs associated with these rate cases.

b. Gannett Flemming Costs

i. AIU's Position

Gannett Flemming, a consulting firm hired by AIU, prepared a depreciation study for AIU in this proceeding. AIU states that Staff witness Ebrey accepts its rebuttal position for the costs of the depreciation study; however, AIU claims she fails to take into account invoice updates provided for March and April that include an additional \$25,000 in post filing support. It is AIU's position that Ms. Ebrey only accounted for \$20,000 of actual post filing support, for only two months of work – January and

February 2008. According to AIU, it incurred \$45,000 of actual post filing support through April compared to Staff's \$42,000 proposal meant to cover the entire post filing cost. AIU contends that considering the electric depreciation study remains contested and that total post filing support costs through April are 41% of the total proposal ($\$45,000 / \$111,000 = 41\%$), AIU requests post filing support in the amount of \$25,000 per electric utility and \$12,000 per gas utility, and complains that Ms. Ebrey only proposes allowing \$10,000 per utility for post filing support.

ii. Staff's Position

Staff accepts AIU's levels of reduced costs for the depreciation studies; however, Staff says it is unable to accept AIU's cost projection for costs associated with post-filing support proposed by AIU for either the gas or electric utilities. Staff maintains that AIU has not shown the actual costs estimates from Gannett Fleming. AIU, according to Staff, provided only the total amounts included as rate case expense and did not provide any tracking of actual costs. Staff says that based on invoices received from AIU, an average of \$3,400 per utility (a total of just over \$20,000) has been expended for post-filing support of the depreciation studies. Staff's proposal allows an additional \$7,000 per utility, or a total of \$42,000, for post-filing support for the depreciation studies. Given the level of post-filing support reviewed by Staff at the time of rebuttal testimony, Staff's contends its proposal is reasonable. In its reply brief, Staff explains that it proposes allowing an additional \$17,000 to cover costs for May through the end of the hearings that is in addition to the \$45,000 in costs incurred from November through April that Staff says is supported by invoices.

iii. Commission Conclusion

Although it is not entirely clear, it appears that AIU is proposing to recover \$39,000 from each utility's gas customers and \$35,000 from each utility's electric customers while Staff is proposing AIU be allowed to recover \$37,000 from each utility's gas customers and \$20,000 from each utility's electric customers. Again, while not entirely clear, it appears that the reasons that AIU and Staff disagree about the level of Gannett Fleming costs that should be passed on to ratepayers relates to invoices for March and April, 2008 as well as the level of estimated costs that had not been incurred at the time Staff took its final position. Consistent with its conclusion immediately above regarding legal expenses, the Commission rejects Staff's proposal to exclude from operating expenses costs attributable to Gannett Fleming that have not yet been incurred. Of the proposals in the record, AIU's estimate of the costs is the most reasonable and is hereby adopted.

c. Energy Efficiency Witness

i. AIU's Position

AIU understands that Staff recommends disallowing the entire cost of AIU's energy efficiency expert witness in this case, Mr. Hanser, based on Staff's belief that the

expert witness was hired to provide testimony that does not relate to this rate case. AIU argues that energy efficiency and Mr. Hanser's testimony do directly involve AIU's rate cases and the setting of rates. According to AIU, Mr. Hanser's testimony was an essential component of explaining the Rider VBA proposal. He also testified regarding the programs implemented by other utilities in the Midwest, expenditures directed to such programs, and appropriate spending levels. According to AIU, energy efficiency initiatives directly affect cost recovery, and AIU would only pursue such programs contingent upon approval of Rider VBA. Lastly, AIU argues, without this direct testimony filing, its rate case presentation would have been deficient. Thus, AIU contends the energy efficiency rate case testimony costs are prudently incurred, and should be allowed.

ii. Staff's Position

Staff recommends disallowing all costs proposed by AIU for its energy efficiency witness since, according to Staff, Mr. Hanser's testimony does not relate to the setting of base rates, the subject of the rate cases, but rather discusses energy efficiency programs, their merits, and associated costs. Staff notes that these topics are directly related to the current Docket No. 08-0104, in which AIU petitioned the Commission for approval of the natural gas energy efficiency plan and the associated Rider GER.

iii. Commission Conclusion

The Commission understands that AIU has the burden to prove its case in any rate proceeding, and in order to efficiently accomplish such a task must make judgment calls of what type of witnesses will be needed to present its case to making a proper showing supporting its proposals. The Commission believes it is unlikely that AIU retained services from an expert that AIU believed was not needed. The Commission takes into consideration various factors that come into play in any case, such as preparing a witness, preparing direct examination and reviewing the expert analysis and reports, and meeting with the expert throughout the case. It does not seem logical to the Commission that AIU would retain an expert that it believed it did not need in support of its case. Whether the Commission approves Rider VBA is not relevant, as AIU has the right, and arguably the obligation, to support any proposal it makes in a rate case. AIU's argument that Mr. Hanser was retained in support of Rider VBA is logical. Therefore, the Commission believes the costs for the energy efficiency witness should be allowed and Staff's proposal to remove the costs from operating expenses is hereby denied.

d. Unamortized Rate Case Expense / Amortization Period

i. AIU's Position

AIU asserts that the AG/CUB's recommendation to disallow unamortized rate case expense is essentially asking the Commission to reverse its prior order approving the amortization of costs incurred in association with Docket Nos. 06-0070/06-0071/06-

0072 (Cons.). AIU argues this is inappropriate because such an adjustment would deny AIU the opportunity to recover its Commission approved, prudently incurred costs.

AIU asserts that because it expects to be filing rate cases on a 2-year schedule in the foreseeable future, it proposes to amortize this rate case expense over a two-year period. AIU notes that Staff proposes a 5-year amortization period for gas rate case expense and a 3-year amortization period for electric rate case expense. According to AIU, Staff's proposed amortization periods are too long, and unreasonable in order for AIU to recover gas and electric rate case expense. AIU submits that it has never been on a 5-year rate case filing schedule and AIU argues that facts and issues have changed for both gas and electric delivery systems since the last rate cases were filed. AIU suggests that costs and other rate inputs have become increasingly volatile. AIU further argues that there are several factors influencing AIU's authorized return as well as system improvements that will continue into the future. AIU asserts it is committed to increasing improvements to the electric distribution system infrastructure. These issues, according to AIU, will fuel the need to file rate cases on a more frequent basis. Thus, AIU believes its proposed 2-year amortization period for both gas and electric rate case expenses is reasonable under current and expected circumstances and should be approved.

ii. Staff's Position

Staff recommends an adjustment for rate case expense of \$259,000 in operating expenses for each gas utility and \$215,000 in operating expenses for each electric utility reflecting the inclusion of unamortized rate case expense from prior rate cases. These proposed adjustments reflect Staff's recommended amortization periods of 3 years for the electric utilities and 5 years for the gas utilities. Staff claims these periods are based on time periods between prior rate case filings.

Staff suggests that its proposed amortization periods are consistent with the time periods between the effective dates of the most recent rate changes of AIU. According to Staff, AIU's proposal to recover rate case expense over a 2 year amortization period for both the gas and electric utilities is a rather aggressive amortization period since it will have been 5 years since the current AmerenCILCO and AmerenCIPS gas rates have been in effect and 3 years since the current AmerenIP gas rates have been in effect when the rates in the instant proceedings become effective. According to Staff, while the 2 year period is representative for the time since the last electric rates were set, a 2 year period is shorter than any rate case amortization approved by the Commission in recent history. Staff argues that there is a risk involved with setting a shorter amortization period versus having a longer amortization period, noting that if the amortization period is less than the period rates are in effect, AIU would recover more than the Commission-approved rate case expense. Staff opined that the ratepayers would then bear the risk with no risk to the shareholders of under recovery.

Staff argues that its recommendation is consistent with AIU's pro forma adjustments for rate case expense in these proceedings, which include a component for

unamortized rate case expense. Staff points out that AIU offered no rebuttal to Staff witness Ebrey's discussion regarding the risks involved with a shorter amortization period for rate case expense.

iii. The AG and CUB's Position

The AG and CUB argue that AIU's proposed amortization of prior rate case expenses should be rejected because it allows AIU to over-recover its rate case expenses. According to them, the purpose of including the normalized rate case expense in the cost of service is not to guarantee a dollar-for-dollar recovery of the rate case expense incurred, but rather to allow a reasonable opportunity to recover the cost of the rate case by including what is deemed to be a "normal" rate case expense in the cost of service. The AG and CUB assert that the problem occurs when the actual period between rate cases is different than that assumed in calculating the amortization of rate case expenses. Thus, they recommend eliminating the amortization of the prior rate case costs from the revenue requirement in these cases, which will then reduce AmerenCILCO electric expenses by \$570,000, AmerenCIPS electric expenses by \$570,000, AmerenIP electric expenses by \$570,000, AmerenCILCO gas expenses by \$170,000, AmerenCIPS gas expenses by \$101,000, and AmerenIP gas expenses by \$303,000.

iv. Commission Conclusion

The Commission rejects AIU's proposed two-year amortization period for rate case expenses. From a historical perspective, this is simply too short of a period. While it is true that in the recent past AIU's gas electric rate cases have been relatively frequent, there have been periods lasting almost a decade or more in which the utilities did not request a rate case. The Commission is not certain when the trend of relative frequent rate cases will change, but it fully expects it to happen. Contrary to AIU's suggestions, the regulatory environment is not so changed that it warrants a two-year rate case amortization period. The Commission agrees with Staff that there is a risk to the ratepayers of overpayment if AIU's proposal were adopted. The Commission therefore adopts Staff's proposal to utilize a five-year amortization period for gas rate case expenses and a three-year amortization period for electric rate case expenses.

As for the AG and CUB's proposal to totally exclude from rates the unamortized rate case expenses approved in AIU's last rate, the Commission rejects this proposal. Contrary to their argument, the Commission does not establish a "normal" level of rate case expenses as it does for other types of cost that are prone to variation over time. Instead, the Commission typically allows a utility to capitalize those costs and amortize them over some reasonable period of time. The AG and CUB proposal would deny AIU the opportunity to recover reasonable, prudently incurred costs. To the extent AIU was authorized to recover rate case expenses in its last rate case and there remain unamortized balances of such authorized costs, AIU will be allowed to reflect such costs in rates in this proceeding.

e. Navigant, Concentric Costs

i. AIU's Position

AIU points out that Staff raises several arguments regarding AIU's rate case expense costs relating to Navigant and Concentric. According to AIU, while Staff accepted all expenses invoiced by Navigant, Staff questions the level of the Navigant and Concentric costs leading up to AIU's rate case filing and, according to AIU, generally disregards the supporting facts that costs associated with the Navigant invoices were actually incurred, prudent, and reasonable.

Staff witness Ebrey claims that certain costs associated with Concentric would not have been incurred if AIU had not switched consulting firms from Navigant to Concentric. AIU argues it did not incur additional costs by continuing to work with their expert witness, Mr. Adams, after he left Navigant and began work for Concentric on July 1, 2007. AIU claims that estimated costs of post-filing services increased in October 2007, several months after Mr. Adams switched to Concentric. At that time, AIU explains it reexamined the scope of work requested from Mr. Adams, and determined that AIU would need significantly more post-filing assistance from Mr. Adams than previously anticipated.

AIU asserts that Staff's hypothesis fails to take into account that if the AIU had continued to use Navigant after Mr. Adams had switched firms, they would have been forced to switch their chosen expert witness, who was retained for his experience, knowledge, and familiarity with AIU's operations and business.

AIU also points out that Staff raised concerns regarding a paid Navigant invoice marked —~~D~~ Not Bill.” According to AIU, Staff disregards its explanation that the notation —~~N~~ Do Not Bill To” was an error on the part of Navigant. AIU argues that it should not be penalized for a mistake on a vendor's invoice. In support of this proposition, AIU argues that as Manager of Regulatory Accounting, Mr. Weiss explained that he reviewed the invoice and determined that the total hours billed and the summary hours listed by the consultant was reasonable.

AIU contends that it provided Staff with the Concentric invoices supporting the lead lag study totaling \$100,000, compared with the original budgeted amount of \$130,000. Thus, actual costs are in line with estimates. AIU also contends that it provided invoices supporting the AMS market study totaling \$653,000 compared to the original budgeted amount of \$750,000. AIU accepts the lower amount and applies it to the updated rate case expense.

AIU asserts that while Staff concedes the increased level of complexity associated with rate filings, Staff does not fully appreciate that with increased complexity comes increased costs. AIU witness Wichmann testifies that the discovery process in these rate cases has been far more exhaustive than in the last delivery service rate cases. He states that the post-filing support estimate was increased with

the expectation that Concentric would need to budget for a significant increase in time and expense due to the higher level of complexity in the rate filing and testimony provided with the filing, which AIU says was borne out through substantial additional support for unanticipated issues, including the proposed plant addition disallowances.

ii. Staff's Position

Staff recommends reducing the amount of costs for the Navigant/Concentric consultants by a total of \$270,000 (from \$429,000 to \$385,000 for each gas utility and \$401,000 to \$355,000 for each electric utility). According to Staff, a review of the support provided for Navigant/Concentric costs raises a number of concerns. Staff argues there is a potential conflict of interest for the review and approval of certain charges for payment. Specifically, the conflict of interest issue concerns charges by the consultant who is the son of the Manager of Regulatory Accounting at AMS, the individual to whom the invoices from Concentric and from Navigant are addressed. According to Staff, in most cases, the Manager of Regulatory Accounting signs off that the bills are "OK" to pay. Staff submits that the conflict of interest allowed costs that should not have been paid by AIU as rate case expense for recovery from ratepayers. These costs include entertainment costs, sick pay, incorrect hotel charges, and other travel expenses. There were also billing errors that were not adequately explained, and transition period costs from Navigant paid by AIU. Staff also noted inconsistent and increased billing rates during the duration of the consultation; and budgeted costs for specific projects above amounts expended. Based on these concerns, Staff recommends that the amount of rate case expense associated with Navigant/Concentric consultation be set at \$385,000 for each gas utility and \$355,000 for each electric utility.

Staff recommends that the Commission order AIU to perform an internal study of all instances in which an individual who is responsible for the approval of charges for payment has conflicts of interest with the individuals performing the work or receiving payment for the work. Staff says the Commission should further order AIU to institute safeguards to minimize the future occurrence of instances that raise this conflict of interest, and to report to the Commission the safeguards that are implemented with a copy to the Manager of Accounting within six months of the date of the order in this proceeding.

iii. Commission Conclusion

With regard to the alleged transition costs attributable to Navigant/Concentric, there is no dispute that Mr. Adams changed firms. At that time, AIU believed that it needed to continue its relationship with Mr. Adams to support its rate cases, which the Commission believes to be a reasonable conclusion. Having said that, however, it seems logical that AIU would have to incur additional costs to retain two consulting firms for a period rather than one, as well as to coordinate and administer the activities of two consulting firms rather than one.

With regard to the alleged conflict of interest, AIU attempts to dismiss the possibility by alleging that the AIU employee at issue was not actually approving the costs in question but that it was AIU's attorneys approving the costs. Given the circumstances, AIU's explanation is not convincing. The Commission, however, does not see a need to require AIU to perform an extensive analysis of potential conflicts of interest and report back to the Commission. The Commission simply directs AIU to ensure that such potential conflicts do not occur again and to avoid the appearance of impropriety. If such a situation arises again, any associated expenses will not be viewed favorably to AIU.

AIU claims that it should not be penalized when a vendor incorrectly bills it; however, Staff has raised legitimate concerns about billing errors that the Commission is unable to fully resolve. As a result of the legitimate concerns raised regarding Navigant/Concentric billing issues, the Commission finds Staff's proposed disallowances to be reasonable and they are hereby adopted.

4. Uncollectibles Expense

a. AIU's Position

AIU proposes that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. According to AIU, the data shows an upward trend in net write-offs since 2003. For each of the electric utilities, AIU indicates that net write-offs are highest in 2007. For two of the three electric utilities net write-offs are lowest in 2003. For two of the three gas utilities, the highest net write-offs are in 2006 and the lowest in 2003. AIU submits that this upward trend demonstrates that the most weight should be placed on the most recent data.

b. Staff's Position

Staff proposes a 5-year average of net write-offs as a percentage of revenues consistent with the time period used in the most recent prior AIU rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Staff disputes the claim by AIU that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Staff argues that AIU offers neither any explanation for the increased level of net write-offs experienced in 2007, nor any evidence that the same level of net write-offs will continue into the future. Staff states that the data presented by AIU does indicate, however, that the level of net write-offs fluctuates over time, necessitating the normalization approach.

Staff's proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs also removes the impact of Section 16-111.5A(f) of the Act in the 2007 revenues booked by

AIU. AIU witness Stafford claims that Staff's adjustments to 2007 revenues are inappropriate since Staff did not establish that the 2007 adjustments are unique or provide any supporting analysis to demonstrate that no other adjustments should be made for other variances.

Staff recommends the Commission approve its proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs, including the adjustment removing the impact of Section 16-111.5A(f) of the Act, on the 2007 revenues booked by the utilities.

c. CUB's Position

CUB recommends that pro forma test year uncollectible accounts expense be normalized based on the average of net-write-offs to revenues for the 3 years 2005-2007. CUB's recommendation was adopted by AIU.

d. CNE-Gas' Position

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. However, CNE-Gas believes the Commission must direct AIU to eliminate commodity-related uncollectible recovery from transportation customers. In support of its recommendation, CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to AIU, which does not supply gas to transportation customers. CNE-Gas argues that given recent Commission precedent and the inequity of AIU's charging transportation customers for purchased gas costs, the Commission must require AIU to remove the recovery of uncollectible commodity-related costs from its transportation rate schedules.

e. AG's Position

The AG argues that in order to ensure that the pro forma adjustment accurately reflects actual experience, the pro forma test year uncollectible accounts expense should be normalized based on the average of net-write-offs to revenues for the three years 2005–2007. The AG indicates that AIU ultimately agreed with it on this proposal, making a minor modification that the AG does not dispute.

The AG also argues that the gross revenue conversion factor should be modified so that the revenues used in the denominator are consistent with expenses used in the numerator. According to the AG, AIU includes the effect of uncollectible accounts in its calculations of the Gross Revenue Conversion Factors used to convert the calculated income deficiencies into the required additional revenues, in effect recognizing the additional uncollectible accounts related to the proposed rate changes. In calculating the uncollectible accounts rates to be used in the gas Gross Revenue Conversion

Factors, according to the AG, AIU took the ratio of total uncollectible accounts to gas delivery service revenues excluding purchased gas revenues. The AG argues that this results in a mismatch which overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The AG submits that the uncollectible accounts rates included in the Gross Revenue Conversion Factors should be modified so that the revenues used in the denominator are consistent with the expenses used in the numerator. The appropriate gas Gross Revenue Conversion Factors, according to the AG, are 1.146%, 1.226%, and 0.937% for AmerenCILCO, AmerenCIPS and AmerenIP, respectively, as compared to AIU's proposed uncollectible accounts rates of 5.766%, 4.582%, and 6.116%, respectively.

f. Commission Conclusion

AIU, CUB, and the AG propose that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. Staff proposes a 5-year average of net write-offs as a percentage of revenues. Staff disputes AIU's claim that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Thus, Staff recommends a proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs.

It appears to the Commission that historical data from 2003 understates the uncollectible percentage and unfairly distorts the expense. It also appears that, generally speaking, there is an upward trend in AIU's uncollectibles. Therefore, the Commission finds that the proposal to use a three-year average of 2005-2007 net write-offs divided by revenues is reasonable and should be adopted.

The AG argues that AIU overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The Commission finds that the AG's argument in regards to the Gross Revenue Conversion Factor issue is misplaced. The Commission has considered the level of uncollectibles authorized in this Order when establishing the appropriate Gross Revenue Conversion Factor used to calculate AIU's revenue requirements in this proceeding.

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to both AIU, which does not supply gas to transportation customers, and the transportation customers' suppliers. It appears that no party objects to CNE-Gas' proposal. The Commission finds CNE-Gas' proposal to exclude system and

transportation customers from the recovery of uncollectible commodity costs to be fair and reasonable, it is therefore adopted.

5. Injuries and Damages Expense - AmerenIP

a. AIU's Position

AIU agrees with Staff witness Ebrey's proposal to normalize injuries and damages expenses over a 5-year period for AmerenIP, but has rejected what it describes as her subjective —~~hy~~rid" normalization approach. AIU argues that its normalization calculation appropriately includes all of the AmerenIP electric 2005 actual payments in the injuries and damages expense calculation. AIU contends that the result of this calculation is fair and consistent with the methodology previously approved by the Commission, and results in a true —~~or~~mal" expense level as reflected in Ameren Ex. 20.7.

AIU argues that while Ms. Ebrey purports to use the same methodology to normalize injuries and damages expense that was approved by the Commission in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), she in fact does not. In that case, AIU claims the Commission approved a 5-year average of AIU's injuries and damages expenses. According to AIU, Ms. Ebrey appears to combine this normalization methodology with the one approved by the Commission in Docket Nos. 07-0241/07-0242 (Cons.), where the Commission approved the utilities' actual test-year expenses, adjusted for a highly unusual credit recorded in a prior year. Thus, Staff combines these two different methodologies to produce what AIU believes is an unfair result, by both normalizing and removing costs.

According to AIU, Staff's approach is not reasonable because the point of normalizing is to flatten out the peaks and valleys of a volatile cost component, by averaging actual costs over a reasonable time period. In this case, AIU argues that Staff has subjectively chosen to remove certain costs from this average, which does not result in an accurate —~~n~~ormal" calculation. AIU's proposed cost level averages actual costs over a 5-year period, which according to AIU is a reasonable period of time over which to account for the highs and the lows. AIU also notes that Ms. Ebrey does not claim that AIU's proposed injuries and damages expense level is unreasonable or does not reflect a —~~n~~ormal" amount.

According to AIU, Ms. Ebrey claims that the issue hinges on whether the costs she chose to remove from the 2005 payouts are —~~e~~xreme and unusual." AIU argues that this argument misses the point because AIU considers all injuries and damages to be unusual. There is no —~~n~~ormal and expected" accident which, according to AIU, is why injuries and damages are a volatile cost component. AIU maintains that normalizing flattens out the highs and lows of —~~e~~xreme and unusual" costs, by averaging actual costs over a reasonable time period.

b. Staff's Position

Staff proposes an adjustment to injuries and damages expense for AmerenIP's electric operations that removes consideration of the extraordinary claims included in the 2005 payouts from the calculation of a normalized amount. Staff claims AIU offered no evidence refuting Staff's position that the claims removed from the 2005 payout level were extreme and unusual. Staff states that AIU witness Wichmann was unable to confirm whether or not the type of, as well as the dollar magnitude of, the claims excluded by Staff were likely to occur annually. Thus, according to Staff, the 2005 claims that are outside the routine level and type of injuries and damages expense are appropriately excluded for the calculation to normalize AmerenIP's electric utility injuries and damages expense. Staff recommends that the Commission adopt Staff's adjustment of \$2,654,000 to AmerenIP injuries and damages expense of electric operations.

c. Commission Conclusion

While AIU correctly suggests that it is reasonable to expect injuries and damages expenses to fluctuate from year to year, given the nature and magnitude of the 2005 AmerenIP injuries and damages expenses, this does not appear to be a routine variation. The Commission finds that the injuries and damages expense that occurred at AmerenIP during 2005 is unusually high and should be considered an outlier. The Commission, however, does not agree with Staff's approach to dealing with this unusual situation. By adjusting the 2005 figure and including it in the 5-year average, the Commission observes that Staff changed the 2005 value from the highest of the 5 into the lowest. The Commission believes the superior approach in this situation is to remove entirely the 2005 injuries and damages from the calculation. Based on this conclusion and using the information on Staff Ex. 1.0, Schedule 1.11 IP-E, the Commission effectively finds that the injuries and damages expense for AmerenIP should be based upon the average of 2003, 2004, 2006, and 2007.

6. Energy Toolkit

a. AIU's Position

AIU has proposed recovering the cost of its Energy Toolkit in the operating expense level for each of its utilities. AIU claims that the Energy Toolkit is a unique program that stands on its own merits and would be of value to customers, however, if the Commission does not approve recovery of the costs for this available program as Staff suggests, AIU will have no alternative but to discontinue the program.

While AIU agrees with Staff that there are other sources of information that may assist customers in better understanding and managing their energy costs, AIU avers that there is no other available site that has the capability of automatically loading, storing and analyzing individual customer usage. AIU opines that there is no other site that allows the customer to complete an individualized energy analysis audit based on

AIU's metered usage, area weather, billing cycle data, changes to owned appliances, and individual lifestyle, and then integrates these pieces of customer-specific information in a format that allows a typical AIU residential customer to better understand and manage their energy expenses.

AIU notes that while Staff witness Ebrey researched similar energy efficiency programs on the internet, she did not identify any site that contained the same information as found in the Energy Toolkit. Ms. Ebrey claims she reviewed a number of sites that had information of the type found in the Energy Toolkit. AIU opines that Staff appears to view the Energy Toolkit as being synonymous with any internet site or program related to energy efficiency. AIU submits that Staff's misunderstanding could be due to the fact that many energy efficiency programs have the same goal or objective and provide information and education to customers in an effort to meet this goal. AIU argues that the Energy Toolkit is a unique service that complements the approved programs and is not duplicative of other internet sites.

AIU claims that the Energy Toolkit would even provide benefits to customers that do not have access to the internet. AIU witness Martin states the Energy Toolkit contains functionality that would act as an enhancement to AIU's customer information system. He says this functionality allows call center agents to provide much of the same information and analysis to residential customers contacting AIU via phone just as if the customer accessed the toolkit on the web. The call center agent interface to the Energy Toolkit, AIU claims, allows the agent to assist with an energy audit, explain monthly, seasonal or annual changes to price and usage experienced by a customer. The Energy Toolkit, AIU contends, will also allow the agent to generate and mail a customized report to the caller, and would allow customers that contact AIU by phone to receive much of the same energy analysis information.

AIU asserts that the Energy Toolkit not only provides education and information about energy efficiency, but may also be used by AIU customers or call center agents to understand many aspects of their utility bill including effects of price, metered usage, weather, and billing cycle. The Energy Toolkit, AIU argues, is a single site that will be deployed specifically for AIU gas and electric customers that gathers data and information from a variety of sources, synthesizes the data into a meaningful format, and presents this customer-specific data in a manner that simplifies the process of understanding, comparing, and managing their energy expenses. AIU says the Energy Toolkit costs will not be recovered through Rider EDR.

AIU believes that the Energy Toolkit provides value to its customers by providing customers an informational and educational resource and that enables them to make informed decisions regarding their energy usage. For a customer to try to similarly self-educate, AIU argues, would be extremely difficult, and would require a significant amount of research, time, effort, and analysis. AIU claims the information the Toolkit provides has the potential to save customers significant amounts off of their energy bills over time, depending on the customer and on individual choices. In summary, AIU

believes the Energy Toolkit program provides meaningful ratepayer benefits, thereby justifying recovery of the costs of this program in rates.

b. Staff's Position

Staff recommends an adjustment to disallow costs for the Energy Toolkit because, according to Staff, the new program does not provide any additional benefit or information to AIU's customers that is not already available through other sources, and it is not necessary for the provision of safe and reliable utility service. Staff argues that the program is not as unique as AIU claims. Ms. Ebrey, after referring to a number of similar web sites, indicates she found many sites that required similar AIU customer specific information to be input that would also generate customer specific billing information on energy usage.

Staff maintains that no measurable added value to customers has been identified by AIU. Staff disagrees with AIU's claim that there is value inherent in making the tool available to its customers as an informational and educational resource that might allow customers to make informed decisions regarding their energy usage. Staff opines that this informational and educational resource is simply a different delivery mechanism for information and education that is already planned under the Energy Efficiency Demand Response Plan. Staff argues that it is unreasonable for ratepayers to bear the cost for this duplication of information. Staff thus recommends a \$275,233 adjustment disallowing AIU's pro forma adjustments for the Energy Toolkit.

c. Commission Conclusion

The Commission believes that AIU's Energy Toolkit can assist ratepayers in making decisions and taking actions to improve energy efficiency, reduce energy usage, and ultimately lower their utility bills. While some of the information provided through the Energy Toolkit is available through other resources, the Energy Toolkit is very detailed and personalized for each individual customer. Taking into consideration the relatively modest cost of the program, the Commission finds that the Energy Toolkit program provides customers an excellent opportunity to reduce their energy usage and that therefore the associated costs should be reflected in AIU's rates. In order to ensure that customers are aware of the Energy Toolkit, the Commission directs AIU to periodically include information about the availability of the Energy Toolkit in its bill inserts (if it is not already doing so).

7. Collateral and Prepayments

a. AIU's Position

AIU believes it should be allowed to recover the costs associated with prepayment and collateral posting for gas purchases. AIU claims such additional costs are necessary and will remain necessary unless and until AIU carries investment-grade ratings. AIU says that for gas operations, a cost of providing service is the requirement

that utilities either prepay for certain services or post collateral. Such a requirement, AIU asserts, is due to limited access to unsecured credit, primarily driven by AIU's below-investment grade credit ratings.

AIU insists that cash collateral and prepayments increase the costs of providing gas. For cash collateral postings, AIU says the cost is estimated by finding the monthly negative carry and multiplying by the monthly amount of the collateral postings. AIU states that the negative carry is estimated as the difference between the actual short-term borrowing rates in effect for AIU each month and the actual Federal Funds Target Rate in effect each month. The Federal Funds Target Rate is the rate of interest often received for cash balances posted to counterparties. For prepayments, AIU says it does not receive interest, as prepayments are considered early payment for pending deliveries rather than as cash deposits that are being held over time. Therefore, AIU says the cost of prepaying is estimated by multiplying the actual short-term borrowing rates in effect each month for AIU by the monthly amount of prepayments.

According to AIU, prepayment requirements and collateral postings to assure performance most often arise under North American Energy Standards Board (NAESB) agreements or International Swap Dealers Association (ISDA) agreements with various counterparties. Because AIU's ratings are below investment grade, it says many of its respective NAESB and ISDA counterparties have availed themselves of a contractual right to require the posting of performance assurances. In AIU's view, it is reasonable to expect that many counterparties to these agreements will likely continue to seek to be fully secured with respect to any positive exposure it has until AIU's ratings return to investment grade levels. AIU says if it were to fail to provide prepayment as contractually required, it could be cited for default and could be at risk in its efforts to secure and maintain stable, long-term gas supplies for its ratepayers.

Depending on the circumstances, upon receipt of a request for prepayment, AIU claims it could need to provide prepayment on the same day or on the next business day. Within many of the agreements to which AIU is principal, it says calculations of credit exposure take place daily. In instances where a counterparty calculates exposure to AIU that exceeds any unsecured credit to which AIU is entitled, AIU claims the counterparty would have a contractual right to require a margin posting. Such calculations and margin calls can, and often do, take place each business day. In most cases under ISDA contracts, AIU says counterparties have one business day to post the margin as requested. As is a standard practice within the energy industry, AIU says it performs the same calculations as its counterparties: (1) in order to determine the appropriateness of any margin call received by AIU; (2) to determine whether margin posted by AIU should be returned; and (3) to determine whether AIU should request margin from any of its respective counterparties.

AIU claims that the amounts of cash collateral and prepayment can change monthly or more frequently and are susceptible to change as often as daily. AIU says prepayment amounts may change monthly or more frequently, depending upon the nature of the agreement and whether the transaction is base load or swing. Under a

monthly base load contract, AIU states that the prepayment amounts can vary due to varying estimated monthly volumes and varying prices applicable to the volumes. Under swing packages, AIU says it may exercise a right to call on variable amounts of gas depending upon the need that exists at that time, and prepayment would vary according to gas volumes and pricing. With respect to cash collateral, AIU indicates the amounts may change daily, depending on the nature of each agreement and the transactions executed under each agreement.

AIU claims that if it carried investment grade ratings, in most instances it would be able to pay for gas supplies during the month following the receipt of gas deliveries, which would substantially reduce and possibly eliminate prepayment-related costs currently borne by AIU. AG/CUB witness Effron reviewed the collateral and prepayment costs as estimated by AIU in response to AG Data Request 4.13. He proposes modifications to the prepayment cost amounts estimated by AIU, indicating: (1) AIU excludes the prepayment balances in the first available month in which data was available; and (2) he recommends the latest known applicable interest rate be used rather than the month-by-month interest rates. In addition, Mr. Effron's Schedule DJE-4, page 4, indicates he is averaging the individual monthly amounts of prepayment postings to obtain an average monthly prepayment posting to which he then applies the most current annual rate of interest. In surrebuttal, AIU witness Moloney concludes that the methodology used by Mr. Effron to calculate his proposed —Annual Interest” amounts (AG/CUB Ex. 4.1, Schedule DJE-4, page 4) is acceptable. The —Annual Interest” reflected in AG/CUB Ex. 4.1, Schedule DJE-4, page 4 is as follows: AmerenCILCO (\$353,000); AmerenCIPS (\$76,000); AmerenIP (\$672,000).

Staff witness Ebrey recommends a disallowance of AIU's pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments. She bases the adjustment on her claim that AIU has not shown that these collateral postings and prepayments are solely for purchased gas. Ms. Ebrey also claims that, if the collateral posting and prepayments are solely for purchased gas costs, they would be considered for recovery through the rates determined under the PGA clause, rather than recovery through base rates.

AIU states that Ms. Ebrey opines that prepayments could be reflected in a CWC analysis and AIU believes this makes sense. AIU says that in such an analysis, the Commission takes into account expense leads, or how many days between when a utility acquires goods or services and when it must make a cash payment. According to AIU, with a prepayment, the lead goes from positive to negative. AIU states that instead of, for example, 4 weeks after receipt, a utility might have to pay 2 weeks before receipt. AIU claims this 6 weeks' difference makes a difference to the utility, in that it represents 6 weeks of carrying cost on the cash.

In AIU's view, the evidentiary record supports the following options for recovery of the carrying cost of collateral: through the revenue requirement; recovery through the PGA mechanism; or as a line item in rate base. For the carrying cost of prepayments,

AIU says the record supports recovery either through the revenue requirement, as a component of CWC, through the PGA mechanism, or as a line item in rate base.

b. Staff's Position

According to Staff, the financing costs of prepayments or interest are a component of a utility's cost of capital. Staff claims the interest expense associated with prepayments has not historically been considered an allowable operating expense in revenue requirement development. To the extent that the gas purchases have been included in storage gas included in rate base and a utility's cost of capital reflects the manner in which a utility finances rate base assets, Staff argues that the revenue requirements capture utility interest requirements. AIU claims that the carrying costs of the prepayments which are on the balance sheet of AIU are the costs on which AIU seeks a return. Staff claims that AIU witness Wichmann admitted that no such costs are specifically identified on the AIU balance sheets and that AIU did not actually transfer funds to pay interest, or carrying costs, associated with the financing of prepayments. (Staff Initial Brief at 171-172, citing Tr. at 734 and 737) According to Staff, those carrying costs are not actual out-of-pocket costs associated with gas purchases and therefore recovery would not be allowed through the PGA.

According to Staff, AIU claims that Ms. Ebrey suggests that AIU's CWC would be the appropriate option for recovery of the carrying cost of prepayments. Staff says that response was provided on March 31, 2008, six weeks prior to Staff's rebuttal testimony filing on May 14, 2008. Staff's final position on the recovery of any carrying costs associated with prepayments is set forth in rebuttal testimony and does not recommend recovery of these derived costs through CWC.

Staff states that recovery of costs associated with collateral postings for gas purchase contracts could be considered a case of first impression. Staff indicates that the posting of collateral associated with energy purchases was considered in the recent electric power procurement cases. In those proceedings, Staff says the costs associated with collateral postings were specifically identified as costs to be recovered under Rider PER for AIU. Staff opines that for the sake of consistency, the costs of collateral postings for the gas utilities should be treated in the same manner as the costs of collateral postings for the electric utilities.

Staff does not claim that such costs will be recovered through the PGA mechanism, but rather offers the recovery of the costs associated with collateral postings through the PGA mechanism as an option to be considered by the Commission. Staff states that this proceeding is to set base rates, not to consider specific costs to be recovered through other rate mechanisms. According to Staff, any costs to be recovered through the PGA would be considered in the annual reconciliation dockets to specifically review the costs AIU proposes to recover through the PGA rates.

AIU witness Moloney states that the counterparties will likely continue to seek to be fully secured until ratings return to investment grade levels. Staff states that it

anticipates any rate increases determined in these proceedings would provide some level of comfort to the ratings groups who could raise the AIU credit ratings above investment grade levels. Staff adds that Standard & Poor's ("S&P") has already given AIU a positive outlook. Should AIU's credit ratings be upgraded and the counterparties no longer require to be fully secured, Staff says that ratepayers would be funding a cost that ceases to exist for the utilities, if AIU's proposal is approved. According to Staff, the option for the cost of collateral postings to be recovered through the PGA recovery mechanism, rather than through base rates, would provide some assurance that those costs would only be collected from ratepayers as they are incurred and not through the indefinite future. Staff recommends that the Commission disallow AIU's proposed pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments for the gas utilities.

In its Reply Brief, Staff argues that collateral and prepayments are simply —opportunity” costs and not actual out-of-pocket costs incurred by AIU. Staff says AIU does not write a check to cover interest (carrying costs) related to prepayments. Staff also states that AIU's exposure will cease to exist when ratings return to investment grade levels. Staff complains that no provision is included in AIU's proposal should the ratings return to investment grade levels and exposure ceases to exist between rate case filings.

c. The AG's Position

AIU has included interest related to posting cash collateral and prepaying for gas purchases in pro forma test year gas O&M expenses calculated by taking the average balances of cash collateral and prepayments and applying the short-term rates by month to those average balances. The AG proposes two modifications to AIU's interest calculations. First, the AG says AIU's interest payments should be based upon the full 12 months of data available subsequent to the time debt ratings were downgraded. Second, in calculating the pro forma interest expense, the AG recommends that the latest known applicable interest rate be used rather than the month-by-month interest rates. The AG indicates that the effect of these adjustments is to decrease AmerenCILCO's gas expenses by \$233,000, AmerenCIPS' gas expenses by \$31,000, and AmerenIP's gas expenses by \$391,000. AIU accepts the AG's adjustment.

d. Commission Conclusion

Having reviewed the parties' positions, the Commission finds Staff's arguments to be somewhat confusing and contradictory. In fact, it is not entirely clear what Staff recommends, although it seems to suggest that AIU should not be allowed to recover the costs of collateral and prepayments from ratepayers. The Commission first notes that while AIU may not write checks for collateral or prepayments, it does not write checks for depreciation expense or cost of capital. Those costs are reflected in base rates. Additionally, while there is no provision to change rates should AIU's credit ratings improve between rate cases, there is no provision to change any component of base rates if circumstances change between rate cases. In short, to the extent Staff

argues that AIU should not be allowed to recover the cost of collateral or prepayments from ratepayers through base rates, that proposition is rejected. These appear to be prudent, reasonable costs incurred by AIU during the test year and it is appropriate for AIU to pass the costs on to ratepayers through base rates. The Commission finds the AG's recommended approach for calculating the annual interest cost associated with collateral and prepayments, to which AIU has agreed, to be reasonable for purposes of establishing rates in this proceeding, and it is hereby approved.

8. Reliability Initiatives

a. AIU's position

AIU seeks recovery of costs for reliability initiatives that consist of, among other things, projects for tap fusing, device inspection, lightning arresters, circuit inspection, multiple device interruption, improving worst performing circuits, underground cable replacements, and distribution service replacements. AIU claims that all of these projects are benefiting or will benefit customers.

Staff witness Ebrey and AG/CUB witness Effron propose to disallow AIU's costs related to reliability initiatives. Ms. Ebrey claims that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense and that such costs are not known and measurable. Similarly, Mr. Effron argues that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. In AIU's view, none of the reasons proffered by Ms. Ebrey and Mr. Effron provide a basis to disallow AIU's costs for reliability initiatives.

AIU argues that Ms. Ebrey is wrong that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense. According to AIU, Ms. Ebrey characterizes AIU witness Getz's examples of past instances where the Commission has approved budgeted or estimated expenses as deficient without attempting to explain how. AIU contends that Ms. Ebrey completely fails to address the examples provided by Mr. Getz. Mr. Getz states that in the most recent AIU gas rate cases, rate case expense for all three utilities was based on estimates. AIU further asserts that in the prior electric rate cases, at least five adjustments were proposed based on budgets or estimates. According to AIU, these were: weather normalization adjustments, wage and salary adjustments to labor expense, pensions and benefits, tree trimming, rate case expense, and AmerenIP acquisition cost savings. AIU claims all five adjustments were contested by at least one party in the proceedings, and three of the five ultimately were set based on budgets or estimates.

In the last electric rate cases, AIU explains that for labor expense, incentive compensation was excluded while wage and salary expenses included 2006 budgeted percent increases. AIU says pension and benefits were based on 2007 actual expense. According to AIU, the Commission approved the 2006 budget amount for AmerenIP tree trimming costs and the Commission approved a combination of actual and estimated

amounts for rate case expense. Finally, AIU says AmerenIP acquisition savings as budgeted through 2006 were included in the final determination of revenue requirement.

AIU contends that Ms. Ebrey also is mistaken in her belief that, because projects are currently —being identified and will be engineered and scheduled,” that the costs can not be known and measurable. AIU argues that to the contrary, the broad scope of work to be performed has been identified and included in the pro forma adjustment. AIU claims calculations were made based on the type of work, the labor rates, materials, and equipment involved for the costs in the aggregate. AIU insists that the fact that some engineering and scheduling on these projects is ongoing does not mean that the projects are not expected to be completed. According to AIU, engineering often continues even after a project has started. In AIU's view, the costs are known and measurable.

AIU argues that Mr. Effron likewise fails to support his claim that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. AIU contends that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring. AIU also believes the increases are determinable. AIU says reliability costs have grown from \$816,000 in the 2006 test year to \$2.2 million in 2007. According to AIU, the 2007 expenditures constitute a 265% increase from the test year expenses. AIU claims that it has already spent approximately \$1.5 million related to reliability projects through March 31, 2008. AIU claims these expenditures are on track with budgeted amounts.

In AIU's view, Mr. Effron's claim that there is little or nothing in AIU's actual experience to support the level of reliability spending forecasted by AIU for 2008 is equally unavailing. AIU insists the 2008 expenditures are known, measurable, and on track with budgeted amounts. AIU argues that under the circumstances, past experience is not indicative of current and future levels of reliability expenditures. The Commission has placed increasing emphasis on reliability, and in response AIU claims to have raised the level of reliability spending. AIU asserts that unique coding has been implemented in the past few years to enhance tracking of specific reliability initiatives.

In its Reply Brief, AIU argues that although there may be some flexibility or shifting between items in the reliability plans, it is expected that AIU will still spend the budgeted amounts. In addition, AIU dismisses the AG's contention that there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. AIU claims it has provided evidence that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring.

b. Staff's Position

Staff recommends disallowing AIU's proposed pro forma adjustments for reliability initiatives because they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that

argument. Staff states that while the Commission may approve budgeted amounts in a rate case final order; those amounts have been analyzed by the parties to determine their reasonableness and are not approved simply because they have been budgeted. Staff asserts that there are wide variations between the amounts AIU budgeted for reliability projects in 2007 and the actual costs incurred. Staff claims there is a significant difference between the number of projects planned, or budgeted, as of July 17, 2007 and as of December 31, 2007.

Staff also says there have been multiple changes for each AIU division during a two-month period. Staff cites Section 287.40 of Part 287, which states in relevant part:

These adjustments shall reflect changes affecting the ratepayers in plant investment, operating revenues, expenses, and cost of capital where such changes occurred during the selected historical test year or are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable.

According to Staff there is uncertainty associated with AIU's reliability projects; thus, AIU's pro forma adjustments should be disallowed.

In its Reply Brief, Staff asserts that AIU incorrectly claims Staff proposes to disallow costs associated with reliability initiatives. Staff says its proposal is to disallow the pro forma adjustment based on the increase of the 2008 budget over 2006 actual costs. According to AIU, the actual 2006 level of costs for reliability initiatives has not been proposed for disallowance by Staff. Staff says AIU claims that Ms. Ebrey does not explain how Mr. Getz's examples of approval of budgeted amounts in rate cases fall short. Staff claims, however, that Mr. Getz provided that explanation during cross-examination. (Staff Initial Brief at 175, citing Tr. at 576)

c. The AG's Position

According to the testimony of Mr. Stafford, AIU is experiencing increases in electric operating expenses to undertake and expand their reliability programs. To recognize the effect of these increases, AIU is proposing pro forma adjustments to increase the electric reliability expenditures from the amounts actually incurred in the 2006 test year to the forecasted expenditures in 2008 which increase AmerenCILCO's electric expenses by \$2,526,000, AmerenCIPS' electric expenses by \$1,763,000, and AmerenIP's electric expenses by \$13,613,000.

In the AG's view, the problem is there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. The AG claims AIU's actual spending on reliability programs in 2007 - the year immediately after the test year in these cases - was not materially different from what it was in the proposed test year. Mr. Getz cites the increases in reliability expenditures that have already taken place from the 2006 test year to 2007 and the first quarter of 2008, stating

that spending on reliability projects increased from \$816,000 in 2006 to \$2.2 million in 2007 (representing all three electric utilities combined).

The AG believes that the percentage increase from 2006 to 2007 is not particularly meaningful because of the relatively low base off which the increase is calculated. Even assuming that the spending continues to grow at that rate, the AG states that the total for the three companies would be approximately \$5.8 million in 2008, which would still fall well short of AIU's forecast of \$18.7 million. Of the three companies, the AG claims only AmerenIP saw a significant increase in reliability spending from 2006 to 2007. Even if the spending in 2008 continues at the same rate as in the first quarter, the AG says spending for the full year would be \$6 million, which would still be well short of AIU's forecast of \$18.7 million.

In its Reply Brief, the AG says AIU mischaracterizes the AG's position when it states that AG/CUB witness Effron proposes to disallow all of AIU's costs related to reliability initiatives. The AG says Mr. Effron recommends only that the pro forma adjustments made for reliability initiatives through 2008 be disallowed. To the extent that actual spending in 2007 has increased beyond the 2006 test year levels, the AG includes those increases in its proposed adjustments. The AG recommends that the Commission reject those pro forma increases which it says are inconsistent with actual AIU experience. Even using the first quarter expenditures from 2008 as a guide, the AG claims AIU's total for the year would be only \$7.2 million.

d. Commission Conclusion

Staff has proposed adjustments to disallow AIU's proposed pro forma adjustments for reliability initiatives since they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that argument. Like Staff, the AG recommends that AIU's proposed pro forma adjustments for reliability initiatives be disallowed in their entirety. The AG argues that because neither the trend in actual reliability spending nor the actual spending rate in 2008 through the first quarter supports AIU's forecasts, there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. Both Staff and the AG complain that AIU suggests they propose disallowing all costs associated with reliability initiatives when, in reality, they recommend disallowing AIU's proposed pro forma adjustment that would increase the test year level of these costs.

As an initial matter, it appears that AIU has, either intentionally or inadvertently, mischaracterized the Staff and AG proposals. Contrary to AIU's claim, Staff and the AG do not propose disallowing all costs associated with reliability initiatives; instead, they propose disallowing AIU's proposed pro forma adjustment to the test year level of reliability initiatives. Thus, the only question before the Commission is whether AIU's proposed pro forma adjustment should be reflected in operating expenses for the test year.

The Commission next notes that in her rebuttal testimony, Ms. Ebrey suggests that the vast majority of AIU's proposed pro forma adjustment for reliability initiatives is for pole replacements. The following table derived from Ms. Ebrey's direct and rebuttal testimony shows that her assertion appears to be correct:

<u>Company</u>	<u>Proposed Test Year Reliability Initiatives</u>	<u>2008 Pole Replacements Budgeted</u>
AmerenCILCO	\$2,700,429	\$2,545,592
AmerenCIPS	2,035,118	1,567,040
AmerenIP	<u>13,982,361</u>	<u>12,151,845</u>
Total	\$18,717,908	\$16,264,477

AIU has not explained why it is appropriate for pole replacements to be treated as an operating expense through so called reliability initiatives. In the Commission's view, pole replacements, as a general proposition, are capital expenditures for long lived assets which should be included in rate base. The table in Ms. Ebrey's rebuttal testimony indicates that between 2006 and 2008, AIU proposes to increase pole replacements treated as operating expenses from less than \$300,000 actually incurred in 2006 (Staff Ex. 13.0 at 35) to over \$16,000,000 proposed for 2008. The record of this proceeding does not support AIU's proposal to make proposed pro forma adjustments to electric operating expenses related to reliability initiatives. The Commission rejects AIU's proposed pro forma adjustments in their entirety.

9. Public Utility Fund Base Maintenance Contribution

a. AIU's Position

Section 2-203 of the Act requires certain electric utilities in Illinois to “contribute” their pro rata share of \$5.5 million to the Public Utility Fund. AmerenCILCO, AmerenCIPS, and AmerenIP included expenses for the Public Utility Fund base maintenance contribution (“PUF BMC”) in test year revenue requirements. The total test year revenue requirement for this item for the three utilities is about \$1.6 million.

Section 2-203 expires by its terms on January 1, 2009. AIU indicates that at the time a bill (Senate Bill (“SB”) 1926, as amended by Senate Amendment 1) was pending in the General Assembly that would retain PUF BMC contributions until January 1, 2014. AIU says that despite the fact that PUF BMC contributions may be extended, Staff witness Ebrey proposes an adjustment to exclude expenses related to the PUF BMC from test year revenue requirements.

AIU believes Ms. Ebrey's adjustment to exclude PUF BMC expense is improper for at least two reasons. According to AIU, the adjustment violates the Commission's test year and pro forma adjustment rules. AIU says Section 287.40 of Part 287 provides for pro forma adjustments to historical test year data that are reasonably certain to occur within 12 months after the filing date of tariffs. AIU indicates that tariffs in this proceeding were filed on November 2, 2007 and argues that pro forma adjustments may extend to November 2, 2008. According to AIU, Staff's proposed adjustment relates to an expense item that will not be affected, if ever, until January 1, 2009. The adjustment, AIU contends, is outside the pro forma adjustment period and improper for that reason alone.

AIU also avers that Staff's adjustment is prohibited single-issue ratemaking. AIU argues that there are many different costs that could increase or decrease beyond the test year. AIU says that is the point of limiting the period for pro forma adjustments; to ascertain known and measurable adjustments to test year income and expense. According to AIU, Ms. Ebrey did not undertake a review to determine whether there was any legislation that would potentially increase AIU's costs after January 1, 2009. By recommending exclusion of a single expense item beyond the pro forma adjustment period, AIU asserts that Staff, in addition to violating test year rules, also inappropriately engages in single-issue ratemaking.

AIU says it recognizes the possibility that it may not incur PUF BMC expenses after January 1, 2009. In AIU's view, Staff's adjustment, however, fails to recognize that it is just as likely, if not more likely, that PUF BMC charges will not only be extended, but may be increased above the amounts required by current law. AIU says that in contrast to the one-sided nature of Ms. Ebrey's treatment of PUF BMC charges, it proposes a resolution that it believes is fair to both the companies and ratepayers. Specifically, AIU proposes that rates be set initially based on the level of PUF BMC expense included in Ameren Ex. 43.5. AIU suggests the Commission could authorize an across-the-board change to tariff rates effective January 1, 2009, to reflect PUF BMC funding requirements. If no contributions are required after January 1, 2009, the cost to ratepayers will be \$0, AIU claims. AIU says that if contributions are required, those costs can be properly recovered in rates, dollar for dollar, based on whatever funding level is approved by the legislature. AIU says it would recover their actual PUF BMC contribution expense, no more and no less.

b. Staff's Position

Staff proposed an adjustment to reduce operating expenses for the PUF BMC, which was authorized by Section 2-203 of the Act, but expires on December 31, 2008. Staff states that if SB 1926, as amended by Senate Amendment 1, becomes a Public Act, the PUF BMC would be extended until January 1, 2014, and Staff's proposed adjustment would not be necessary. According to Staff, while AIU offers a number of criticisms of Staff's adjustment, none of those criticisms change the fact that Section 2-203 of the Act will be repealed absent further legislation. Staff asserts that its proposal

provides the Commission an option depending on whether or not the legislature takes further action.

AIU points out that the amount of Staff's proposed adjustment does not consider that a portion of the total amount charged to Account 928 is not assigned to electric distribution operations. Staff agrees with this correction and reflects the adjusted amount in its proposed electric revenue requirements attached to its Initial Brief.

In response to AIU's arguments regarding pro forma adjustments, Staff contends that Section 287.40 addresses only pro forma adjustments that may be proposed by a utility company. Staff claims that Section 287.40 was never intended to limit Staff's ability to propose adjustments. Staff says that AIU's proposal would require ratepayers to pay for a soon to be non-existent PUF BMC, and if collected, AIU would have no obligation to remit the PUF BMC to the Illinois Department of Revenue. According to Staff, AIU wants the Commission to believe that the recovery of an expired cost accomplishes the requirement that all rates or other charges be just and reasonable as required by Section 9-101 of the Act.

Staff also disagrees with AIU that Staff's proposed adjustment to remove the PUF BMC is prohibited single-issue ratemaking. Staff states that single-issue ratemaking would occur if the Commission would, in a separate and presumably subsequent proceeding, consider or revise a single revenue or expense item. (Staff Reply Brief at 84, citing Business and Professional People for the Public Interest v. Illinois Commerce Commission, 146 Ill. 2d. 175, 244, 585 N.E.2d 1032) ("BPI II") In the instant proceedings, Staff indicates that AIU is seeking a general increase in rates under Section 9-201 of the Act. Staff says a general increase in rates is intended to consider all components of the ratemaking formula (i.e., revenues, expenses, rate base and rate of return). Therefore, Staff does not believe AIU's single-issue ratemaking argument is applicable.

c. Commission Conclusion

Based upon its review of the record and the parties' arguments, the Commission rejects Staff's proposal to reduce operating expenses associated with the PUF BMC. The Commission concludes that this possible change in the statute is not known with a sufficient level of certainty to incorporate the potential impact in this proceeding. Additionally, the Commission is concerned that the actual change, if it were to happen at all, would not take affect until January 1, 2009. As for AIU's alternative proposal, because it has rejected Staff's proposed disallowance, it seems moot. The Commission is also concerned that were it adopted, this proposal might be considered single-issue ratemaking.

10. Depreciation Life for Electric Distribution Equipment

a. AIU's Position

AIU presents the testimony of and a depreciation study prepared by Mr. Wiedmayer of Gannett Fleming. AIU asserts that the service life of utility property can be defined as the period of time from its installation until it is retired from service. According to AIU, the currently approved service life estimates were determined in conjunction with utility-specific service life studies that were performed by three depreciation experts at different firms for each electric utility. Mr. Wiedmayer proposes estimates based on his informed engineering judgment after an analysis of available historical service-life data related to the property, a review of management's current plans and policies, a review of the prior approved service-life estimates, and a review of service lives estimated by other electric companies. AIU submits that both the approved lives and proposed lives were reached using industry-standard methodologies, and while these studies revealed a wide range of estimated service lives, AIU suggests there is nothing unusual about this.

AIU complains that Staff's recommendation proposes no specific adjustment, but suggests that the depreciable lives for certain distribution plant accounts such as meters should be the same for all three utilities. Staff witness Rockrohr premises his recommendation on the observation that AIU is now operating under common management and, therefore, equipment is to be constructed and maintained to the same or nearly the same standards among all three utilities. AIU avers that Mr. Rockrohr reasons that the same equipment would remain in service the same number of years for each of AmerenCILCO, AmerenCIPS, and AmerenIP, and therefore should be assigned the same service life.

AIU states that absent common management, different depreciable lives were appropriate, and that it was reasonable for CILCO, CIPS, and IP to have different depreciable lives for distribution plant when the utilities were not affiliated. AIU submits that the mere fact of common management does not justify use of a single depreciable life for distribution plant.

AIU argues that management practice is just one factor to be used in determining depreciable lives, not the only or dispositive one. AIU claims that Mr. Wiedmayer's study showed other factors justified a wider range of estimated service life. According to AIU, his study determined that over 500 different models (or variations) of meters are in service on the AIU system, many of which were manufactured by a number of different companies, installed at different times, and subject to different conditions of service. AIU posits that Staff's recommendation is not based on a particularized study but is instead based on the fact that consolidation has taken place.

While Mr. Wiedmayer testified that he would expect the depreciable lives for certain plant accounts to be more similar in the future, he does not believe that a single depreciable life is warranted at this time. AIU notes that the utilities have only been

affiliated since 2005, and submits that this is too short a period to have a material effect on the service lives of utility plant.

b. Staff's Position

Mr. Rockrohr recommends that AIU utilize a common depreciable life for electric distribution equipment if that equipment is used at all three utilities in an identical or nearly identical manner. Mr. Rockrohr acknowledges that the average age of equipment in the field at the three utilities is not identical. He explains, however, that looking forward, the service life of equipment at each utility will depend more upon the inspection and maintenance practices now in place than on the existing age of the equipment that is in the field. Mr. Rockrohr maintains that AIU should select a common depreciable life for equipment categories in which the equipment is utilized in an identical or nearly identical manner.

c. CUB's Position

CUB opposes AIU's recommendation to assign different service lives to distribution equipment that is used in an identical fashion in each utility's service areas in central and southern Illinois. CUB notes that Mr. Wiedmayer explains that the Commission approved the present depreciation rates for AmerenCILCO in 1994, for AmerenCIPS in 1992, and for AmerenIP in 1992. The depreciable lives of various categories of distribution equipment were set at those times. In those years, CILCO, CIPS, and IP were not affiliated with one another, and distribution facilities were not necessarily utilized and maintained in the same manner at each of the utilities. CUB notes that while it may have been reasonable that the same or similar equipment was assigned a different depreciable life at each utility in the past, the situation has changed. CUB submits that AIU now uses the same or nearly the same electric distribution construction and maintenance standards at each utility, and if the same equipment is to be installed and maintained in an identical manner at each utility then it is logical that the same equipment should, on average, remain in service the same number of years.

CUB argues that in order to maintain consistency of the calculation of the depreciable lives between similarly maintained equipment, the Commission should adopt Mr. Rockrohr's recommendation to amend AIU's depreciation schedules in a manner that provides the same depreciable lives for categories of distribution equipment that is installed and maintained in an identical fashion at each utility.

d. Commission Conclusion

The Commission notes that prior to the utilities' affiliation, different depreciable lives were determined as appropriate for each utility. The service life estimates were determined in conjunction with utility-specific service life studies that were performed by depreciation experts for each electric utility. These studies were based on available historical service-life data related to the property, a review of management's current plans and policies, a review of the prior approved service-life estimates, and a review of

service lives estimated by other electric companies. The Commission believes that establishing single service lives for certain types of electric distribution utility property may be appropriate in the future but is not practical at this time.

Among other things, Staff and CUB fail to take note that many different depreciation lives were determined at different times and subject to different conditions of service at the time of installation. Thus, the Commission believes that the current approved service life estimates that have been assigned to plant property should remain. However, AIU is instructed in future rate cases to consider the possibility of assigning common service lives for plant accounts if they are utilized in the same manner at each utility in order to maintain consistency in the calculation of the depreciable lives among similarly maintained equipment.

11. Net Salvage Method for Depreciation Expense

a. AIU's Position

AIU notes that the general aim of depreciation accounting is to distribute the cost of fixed capital assets, less net salvage, over the estimated useful life of the assets in a systematic and rational manner. AIU witness Wiedmayer proposes using the traditional, accrual method for accounting for net salvage, by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. AIU points out that this is the approach used by the Commission for many years and by the majority of commissions in other jurisdictions. AIU submits that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption.

AIU argues that IIEC witness Selecky's proposed net salvage approach is a departure from Commission precedent, and is inconsistent with the approach used by the vast majority of state commissions. In light of this fact, AIU argues that one would expect Mr. Selecky to have compelling reasons before asking the Commission to alter its traditional practice. According to AIU, he presents none, however, and a number of other considerations counsel against adopting his approach.

First, AIU argues IIEC's proposed net salvage approach is inconsistent with the USOA. AIU notes that the USOA requires utilities keep their accounts on the accrual basis. AIU points out that utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. AIU submits that to only recognize salvage-related costs at the time any salvage-related dollars change hands would be to follow the —cashbasis of accounting, contrary to the instructions of the USOA.

According to AIU, Mr. Selecky's approach also violates the ratemaking principle of customer equity. AIU argues the principle of equity demands that the customers who enjoy a given benefit should pay their portion of the related costs, no more, no less.

AIU submits that while its approach would allocate net salvage costs associated with given assets to the customers being served by those assets, IIEC's approach would mismatch those who benefit from the net salvage costs with those who pay such costs.

AIU posits that IIEC's proposal would also recover the entire element of an asset's cost of service from customers that either received no benefit from the asset or only a portion of the asset's service value. AIU argues this is a violation of the principle of equity, and no different than requiring one generation of customers to pay the entire original cost of an asset that served many generations.

b. IIEC's Position

IIEC proposes an adjustment to depreciation rates because of what it views as the inequity of using net salvage cost calculations based on historical data. IIEC also objects to what it calls the inclusion of unproven, inappropriate inflation costs in depreciation rates. IIEC also argues that if the calculation of depreciation rates is not changed, it will fail to recognize the time value of money.

According to IIEC, AIU's depreciation expense should reflect the actual net salvage costs caused by ongoing transmission, distribution and general plant retirement, similar to the treatment afforded other expenses. IIEC argues the Commission should not approve AIU's proposed net salvage ratios, which it claims incorporate estimated inflation and ignore the purchasing power of the dollar. According to IIEC, AIU's estimates of net salvage are based on judgment, considering factors that are not well-defined and historical net salvage data that AIU admits were in some instances unreliable and limited. IIEC claims these deficiencies in the historical data led Mr. Wiedmayer to rely on net salvage estimates from other electric utilities. IIEC notes that the net salvage percentages that AIU proposes to incorporate in its depreciation rates are not exclusively based on AIU's own data, and IIEC argues that those percentages do not reflect AIU's actual experience.

IIEC contends that there is no dispute that inflation, which is at the core of IIEC's challenge to AIU's calculated depreciation rates, is a component of the net salvage estimates AIU has built into its proposed depreciation rates. IIEC says Mr. Wiedmayer used historical net salvage data to develop net salvage percentages by dividing the net salvage cost associated with retiring an asset by the original cost of the asset. IIEC insists that because the calculation uses nominal dollar amounts, net salvage cost is expressed in current dollars and the original cost of the asset is stated in the dollars for the year the asset was originally placed in service, inflation over the period between the two events is captured in the calculation. IIEC notes that the pre-inflation, nominal dollar figures associated with past investments are divided into the post-inflation, real dollar amounts for the cost of salvage. This calculation, IIEC argues, incorporates an unproven assumption that future inflation will occur at the same rate as past inflation, resulting in different ratios than actual experience would indicate. IIEC says the net salvage percentage is then incorporated in a depreciation rate that is applied uniformly over the useful life of the assets in the relevant account. According to IIEC, application

of the single rate means that customers today will pay the same number of dollars as customers 30 to 40 years in the future, notwithstanding the difference in real purchasing values of those nominal dollars. IIEC contends that customers today will pay the same number of dollars as future customers despite the fact that current salvage expenses are much lower than the amounts collected from current customers and that without accounting for implicit inflation at a historical rate, which is inherent in the calculation. IIEC contends that the effect of these methodological flaws is an excessive level of depreciation expense.

IIEC argues that another adverse effect of the methodological flaws is unfairness in AIU's rates, and that the flawed calculations will foster significant inter-generational inequities. IIEC submits that under AIU's proposal, AIU customers will pay costs today that the utility may not incur for another 40 years. Moreover, IIEC argues in terms of real dollars, the uniform nominal amount that AIU would charge customers over the decades of assets' lives would actually require significantly less of future ratepayers.

c. The Commercial Group's Position

The Commercial Group agrees with Mr. Selecky that AIU has inflated depreciation expense by over-projecting net salvage expense, and that AIU proposes net salvage expense that is 2 to 5 times greater than AIU's current net salvage expense. The Commercial Group submits that AIU does so by projecting future inflation rates into salvage expense calculations. The Commercial Group avers that guessing and projecting the inflation rate for the next 30, 40, or 50 years into salvage expense is not likely to produce a result that follows actual salvage cost. The Commercial Group suggests this is demonstrated by the fact that actual current salvage expense is many times lower than the proposed salvage expense rate recovery. What this means, according to the Commercial Group, is that ratepayers in 2009 would pay the same actual dollar amount for the salvage expense of a set of electric poles to be replaced in 2040 as would a ratepayer in 2039; and considering the effect of inflation, means that the 2039 ratepayer would pay significantly less in real dollars for salvage of those poles in 2040 than would the ratepayer in 2009.

The Commercial Group submits that this represents a substantial intergenerational shift in depreciation expense that unfairly harms current ratepayers. Accordingly, the Commercial Group urges the Commission to adopt the lower depreciation rates as recommended by Mr. Selecky.

d. Commission Conclusion

The Commission does not concur with IIEC and the Commercial Group's proposal to depart from the Commission's current treatment of net salvage costs; specifically, using the traditional, accrual method of accounting for net salvage. Although there are some regulatory commissions that have moved away from the methods prescribed for depreciation, this Commission is not inclined to do so as the evidence does not show it is necessary. It has been appropriate to use the traditional

method by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. This method of depreciation allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. IIEC's complaint that customers today will pay the same number of dollars as future customers represents a misunderstanding or misrepresentation of the purpose of systematic recovery of depreciation expense, which provides for rate recovery of long-lived assets over their expected useful life. In contrast, the net salvage approach advocated by IIEC and the Commercial Group would improperly push costs into the future that are more appropriately borne by current ratepayers. The Commission understands why such an approach may appear attractive in the short-run, but in the long-term it provides no benefit to ratepayers in aggregate. Further, contrary to the Commercial Group's assertion, the Commission concludes that AIU's reliance on some net salvage estimates from other electric utilities does not result in over-projecting net salvage expense relative to AIU's current net salvage expense. In conclusion, the accrual method for calculating net salvage is consistent with the Commission accounting practices for regulated utilities, has been accepted, deemed appropriate for years, and the Commission remains convinced that it is appropriate in this case.

12. NESC Violation Correction Costs After the Test Year

a. AIU's Position

AIU agrees to track costs associated with correcting NESC violations as Staff proposes, however, AIU opposes disallowance of those costs. AIU states that the Commission and Staff imposed a number of programs, initiatives, and other requirements of Ameren during the various acquisition dockets. In 2003, in Docket No. 02-0428, the Commission approved Ameren's acquisition of CILCORP, which included its operating utility subsidiary, CILCO. In 2004, in Docket No. 04-0294, the Commission approved Ameren's acquisition of IP. In 2005, AmerenUE transferred its service territory in Illinois to AmerenCIPS. AIU claims that assuming responsibility for unknown past violations of the NESC were not made part of the conditions of approval. According to AIU, it has fulfilled all of its responsibilities required in the Commission's acquisition dockets and it would be unfair and inequitable to impose, at this time, additional conditions of acquisition by holding AIU responsible for costs due to improper initial construction occurring prior to Ameren ownership.

AIU contends that a significant portion of the violations of the NESC were due to improper initial construction which occurred prior to Ameren ownership. According to AIU, it has made certain commitments in response to the NESC issues, including, an agreement to track all costs associated with NESC compliance, an agreement to forego current recovery of test year expenses that it has incurred for NESC compliance, an agreement to forego future recovery related to the replacement of otherwise grandfathered single cross-arms at railroad or interstate highway crossings, and an agreement to forego future recovery for the replacement of down guys or overhead guys that were improperly constructed after Ameren ownership.

AIU submits that it has put forth a fair and responsible proposal under which its shareholders will bear the costs associated with violations occurring after Ameren assumed ownership of AmerenCILCO and AmerenIP. AIU argues that disallowing all costs associated with correcting NESC violations due to improper initial construction by a previous owner should be rejected for various reasons. AIU avers that the proposed disallowance fails to find AIU's prospective investments are imprudent, and further posits that the proposed disallowance is at odds with the goals and objectives of the Act. AIU further submits that Staff witness Rockrohr's recommendation runs afoul of the Commission's long held policy of encouraging the acquisition of financially troubled utilities.

AIU argues that in determining whether future replacement costs should be recovered, the Commission's attention should focus on the decision of AIU management to make the prospective replacements and not on past construction efforts, and submits it would be improper to look at the conduct of previous owners. Moreover, AIU argues it does not seek recovery for NESC compliance measures in this proceeding. AIU notes that it has agreed to withdraw its request for recovery for those replacements proposed as test year costs. AIU avers that it is premature to conduct a prudence examination of its post-test year NESC compliance efforts, and therefore, Mr. Rockrohr's disallowance should be rejected as it is unripe. AIU also states that Mr. Rockrohr has failed to consider the prudence of making NESC required replacements.

AIU points out that Mr. Rockrohr's position is that the utility should bear all the consequence of all improperly constructed facilities, without regard for who constructed the facilities or the adverse financial impact on AIU. While Mr. Rockrohr believes it would be unfair for customers to bear any consequence of the improper initial construction, AIU submits that there is no evidence that he contemplated the impact of his recommendation on AIU's financial health. AIU contends that while Staff believes that AIU could have made itself aware of pre-existing NESC violations by inspecting ~~some~~ of the distribution circuits, AIU submits that the facts suggest otherwise. AIU notes that the AmerenCILCO, AmerenCIPS, and AmerenIP service territories cover approximately 40,000 square miles and contain over 45,000 miles of distribution circuits supported by over 1,000,000 distribution poles. AIU submits that it is pure conjecture that spot checks would have uncovered the NESC violations at issue here.

AIU argues that it exercised due diligence and proceeded with its acquisitions based on the relevant information that was available at the time, and notes that the Commission approved each of the acquisitions with no findings of any shortcomings in Ameren's due diligence undertakings. AIU does not agree with Staff's assertion that in the event a utility system is not compliant with the NESC, corrective action must be taken pursuant to Commission Rule, 83 Ill. Adm. Code 305, "Construction of Electric Power and Communication Lines" ("Part 305"). AIU submits that Part 305 of the Commission's Rules is not as inflexible as Staff suggests. AIU notes that Section 305.130 provides for exemptions from NESC standards, and avers that the Commission

can provide waivers of NESC standards or even modify the standards if the Commission so chooses.

b. Staff's Position

Staff recommends that AIU's costs associated with correcting certain NESC violations that exist due to improper initial construction should be disallowed from rate recovery. Mr. Rockrohr expresses concern that AIU intends to charge customers for re-constructing distribution facilities that CILCO, CIPS, and IP initially constructed improperly, and in the process earn a return on the costs associated with correcting the NESC violations. He further notes that as AIU's budgeting system does not separately track dollars associated with correcting NESC violations, he recommends that the Commission require that AIU track costs for correcting all NESC violations, and separately account for such costs. He also recommends that the Commission order that costs to correct violations that AIU itself caused not be approved for inclusion in rate base.

Staff argues that the alleged pre-existence of the violations prior to Ameren's ownership of the utilities is not a valid reason to pass these costs on to ratepayers. Staff submits that Ameren was not coerced or forced into purchasing CILCO and IP, and could have made itself aware of pre-existing NESC violations simply by inspecting some of the existing distribution circuits. Staff avers that as the merger of CIPS and UE was the catalyst for the formation of Ameren as a holding company, NESC violations within the operating area of CIPS can not be considered the fault of a prior owner. Mr. Rockrohr explains that based upon AIU's estimates, the compromise that AIU offers (whereby AIU would correct NESC violations consisting of single cross-arms at railroad and interstate highway crossings at shareholder expense) would equate to ratepayers paying for correcting about 95% of the NESC violations that are estimated to exist on AIU's system due to improper initial construction. Mr. Rockrohr posits that the compromise that AIU suggests is not reasonable, therefore he continues to recommend that the Commission order AIU to separately account for costs associated with correcting NESC violations that exist due to improper initial construction, and disallow those amounts from rates.

c. Commission Conclusion

As the Commission understands it, the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP constructed certain electric distribution facilities in a manner that are not in compliance with the NESC. Generally speaking, Staff objects to AIU passing along to ratepayers costs that are incurred to correct distribution facilities that were initially constructed in a manner that does not comply with the NESC. While it appears that AIU no longer requests to pass such costs on to ratepayers in this proceeding, AIU insists that it should not be responsible for the actions of the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP and should be allowed to recover from ratepayers the costs of remedying such NESC violations in the future.

Staff also recommends that the Commission order AIU to separately track and account for costs associated with correcting NESC violations that exist due to improper initial construction. AIU does not object to the recommendation. The Commission believes it is reasonable and it is hereby approved.

It appears that for purposes of establishing rates in this proceeding, there is no contested issue regarding proposed adjustments to rate base or operating expenses that flow from the reconstruction of electric distribution facilities that were improperly constructed in violation of the NESC. The Commission is, nevertheless, concerned about the position taken by AIU regarding this issue. The proposition that ratepayers should be responsible for paying the cost associated with improperly constructed electric distribution facilities as well as the cost of correcting the improperly constructed facilities is not one with which the Commission agrees. The suggestion that by disallowing from rates such costs constitutes an additional condition on any reorganization or merger is also rejected. In the reorganization or merger proceedings, AIU did not inform the Commission of the possibility that electric distribution facilities were not in compliance with the NESC and, as a result, the Commission did not consider the question or make any ruling on the matter.

Business decisions were made that resulted in CILCO, CIPS, and IP being owned by Ameren. The management and owners of Ameren, not ratepayers, made those decisions and they must live with the consequences. In this instance, the consequences will be that ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC. While there is no rate base or operating expense impact in this proceeding, AIU is on notice that the Commission has no intention of passing such costs on to ratepayers in future rate cases. As for AIU's suggestion that Part 305 is flexible, the Commission simply reinforces that it expects AIU to comply with all applicable Commission rules, including Part 305.

13. Gas Account 880 – AmerenIP

a. AIU's Position

Staff proposes to adjust the test year expense for AmerenIP's gas Account 880 "Other expenses" because Staff believes the expense is high when compared to other time periods. Account 880 includes "the cost of distribution maps and records, distribution office expenses, and the cost of labor and materials used and expenses incurred in distribution systems operations not provided for elsewhere, including the expenses of operating street lighting systems and research, development, and demonstration expenses." (USOA for Gas Utilities Operating in Illinois) Staff proposes that a 3-year average (2005-2007) be used instead, reducing AmerenIP's Account 880 expense levels by \$1,026,000. According to AIU, Staff does not challenge the prudence of the expenditures shown in AmerenIP's Account 880. Instead, AIU says Staff only argues that the expense appears to be somehow ~~excessive~~ "excessive." AIU claims Staff's adjustment should be rejected for two reasons. First, Staff proposes an adjustment for

an account that appeared —high” but ignored countervailing adjustments for accounts that may have been lower in the test year than other years. Second, AIU claims to have shown that it is not reasonable to evaluate this account on an individual basis. AIU says account 880 is only one of a number of related transmission and distribution (“T&D”) O&M accounts where costs can shift and vary year to year based on the level of activity and required work.

According to AmerenIP, the majority of O&M activities performed on its T&D facilities is very similar, and are managed, supervised, and performed by essentially the same resources, which include AmerenIP employees and third-party contractors. AIU claims the shift or change in costs between these accounts occurs based on the specific level of O&M activities needed and performed for the T&D main facilities in a given year. AIU states, for example, exposed pipe remediation, leak surveys, leak repairs, right-of-way clearing, main relocations, corrosion control, and painting are types of O&M work performed on T&D mains that may vary based on inspection cycle, facility condition, problem severity and magnitude, or highway department needs. Based on the classification of main, either transmission or distribution, and the type of work, operations or maintenance, AIU says the appropriate account is charged. AIU argues that it would be expected that, depending on the specific O&M needs, costs would not remain static among accounts.

AIU indicates that Mr. Lounsberry discussed Account 880, which is a sub-set of the larger grouping of T&D O&M accounts. To obtain a more accurate representation, AIU suggests that Staff should review the O&M costs for the T&D system in aggregate. In AIU's view, this approach provides a more accurate assessment of the reasonableness of the O&M costs versus evaluating individual accounts. During the period of 2005-2007, which includes the test year, AIU says the aggregate costs for AmerenIP's 800 series accounts have been reasonably consistent, with a slight upward trend. According to AIU, AmerenIP's average over this period for all T&D O&M costs is approximately \$59.93 million, and no year deviates from this average by more than 6%. AIU argues that because it is reasonable to expect overall O&M costs to increase each year, the overall level of T&D O&M costs show that, when viewed in the aggregate, there is no basis for a concerns that T&D O&M costs are excessive.

AIU contends that Staff's logic could also be applied to individual accounts where 2006 represented the lowest level of expense for 2005-2007. AIU notes that Staff does not recommend increasing the amounts requested to any account that had the lowest expenditure in 2006 and higher expenses in 2005 and 2007. AIU claims that Accounts 878 "Meter and house regulator expenses" and 879 "Customer installation expenses" both have significantly less costs in 2006 than in either 2005 or 2007 and are below average for the 3 years. Using Mr. Lounsberry's analogy, AmerenIP asserts that since both of these accounts are lower than the three-year average for 2006, using averages rather than actual costs would require an increase rather than a decrease.

In addressing Mr. Lounsberry's concerns regarding cost levels in other T&D accounts, Accounts 856 "Mains expenses," 863 "Maintenance of mains," 874 "Mains

and services expenses," and 887 "Maintenance of mains," AIU asserts that costs shift between the accounts, so that the appropriate way to determine if the O&M costs are just and reasonable is to evaluate and understand the trend for the overall cost of operating and maintaining the T&D system. In rebuttal testimony, Mr. Lounsberry indicated he no longer had any concerns regarding AmerenIP's Accounts 856, 863, 874, and 887 requested O&M levels. According to AIU, Staff has accepted that individual T&D accounts may vary from year to year, but that this does not mean the expense in any one account is unreasonable.

AIU asserts that Account 880 is one of the accounts from 850 through 894 that capture O&M costs for the overall T&D system. AIU says Account 880 can vary from year to year resulting in cost fluctuations in individual accounts and should be considered as part of the aggregate. AIU believes these T&D O&M costs, including costs of Account 880, must be considered at the aggregate level, as opposed to the individual account level, to accurately evaluate the O&M costs for the T&D system.

b. Staff's Position

Mr. Lounsberry recommends a reduction of \$1,026,000 to AmerenIP's requested test year amount for Account 880. He states that AmerenIP requested \$9,505,000 for its Account 880, but that his review found that AmerenIP's test-year expense was higher than any other period reviewed for this account. Mr. Lounsberry's review was limited to the three-year period 2005-2007, because in 2005 IP was transitioning to AIU's accounting system. Therefore, Staff believes any expense data for IP prior to 2005 uses a different accounting system and will not necessarily correlate to the AIU accounting system.

AIU responds that it is not reasonable to evaluate this account on an individual basis. AIU witness Colyer states that Account 880 is only one of a number of related T&D O&M accounts where costs can shift and vary year to year based on the level of activity and requirement work. Instead, Mr. Colyer indicates that Account 880 should be considered as a variable part of the aggregate 800 series of O&M accounts for the T&D system. Mr. Colyer also notes that Mr. Lounsberry's proposal does not indicate AmerenIP's proposed Account 880 amount was unreasonable, but that the requested amount was just higher than other years.

Mr. Lounsberry does not agree with Mr. Colyer's assertion that the aggregation of about 40 different accounts will demonstrate the reasonableness of any individual account. However, in order to provide a complete review, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Staff says this review indicates that when using the same 3-year period (2005-2007) that Mr. Lounsberry had used to normalize the individual Account 880 amount to review the aggregation of the 40 different 800 series accounts, his analysis came up with virtually the same result as looking at Account 880 individually. Specifically, Staff claims the 3-year average from aggregating the Account 800 series of T&D O&M amounts shows AmerenIP's test year request was about \$940,000 above that average. According to Staff, the review of the

aggregate accounts also supports Mr. Lounsberry's original adjustment to reduce the Account 880 expense amount by \$1,026,000.

c. Commission Conclusion

The Commission has reviewed the record and the parties' arguments regarding the proper costs to include in Account 880. As Staff's analyses demonstrate, AIU's arguments do not withstand scrutiny. Whether Account 880 is analyzed individually or with the other O&M accounts for T&D in aggregate, the test year amounts are abnormally high by approximately \$1 million. As a result, the Commission finds Staff's proposal to reduce the amount of Account 880 costs that AmerenIP may pass along to ratepayers by \$1,026,000 reasonable and it is hereby adopted.

14. Gas Accounts 830 and 834 - AmerenCILCO

a. AIU's Position

With regard to gas Accounts 830 "Maintenance supervision and engineering" and 834 "Maintenance of compressor station equipment" for AmerenCILCO, Staff proposes to adjust the expense levels in these accounts to reflect an average of the expenses over a 5 year period from 2003- 2007. According to AIU, no party has suggested that the expenses in these accounts were not prudently incurred; rather, Staff suggests that the test year levels of these expenses were excessive. AIU maintains that the reason for the variation of costs from year to year in Accounts 830 and 834 is that internal labor costs can shift between accounts from year to year as a result of the cyclical nature of maintenance activities, capital projects, and the type of activity being performed. AIU asserts that it is not appropriate to consider increases in costs recorded to Accounts 830 and 834 in isolation. Rather, AIU says accounts 830 and 834 must be considered in the context of the combined gas storage accounts.

According to AIU, Staff witness Lounsberry's logic could also be applied to AmerenCILCO gas storage accounts where 2006 represented the lowest level of expense in the 2005-2007 periods. AIU relates that Mr. Lounsberry does not recommend increasing the amounts requested for any accounts that had the lowest expense in 2006 and higher expenses in 2005 and 2007, such as Account 816 "Well expenses" where the expenses were \$211,724, \$141,028, and \$179,197 respectively for 2005-2007. AIU complains that Mr. Lounsberry also does not explain why the variations in Accounts 830 and 834 were unusual or what, if anything, made the test year expense unreasonably high.

To properly capture these variations, AIU claims Mr. Lounsberry would need to average costs for all related accounts, not just the ones that were higher. According to AIU, overall expense for O&M for gas storage for AmerenCILCO is relatively stable over time. AIU claims the low expense level in 2007 was due to an unusual capital expenditure amount for 2007 that shifted resources from O&M to capital expenditures. In AIU's view, this shows that the variance over the years to accounts like Accounts 830

and 834 represents shifts of expenditures between accounts, but not an overall increase in O&M expense.

On rebuttal, Mr. Lounsberry argues that using the 2003-2007 period for AmerenCILCO's Accounts 830 and 834 shows the aggregate amounts for 2004 and 2005 are the highest of the period. AIU contends that the 2005–2007 data for the combined gas storage accounts is more current and therefore more representative of expected ongoing costs going forward, because it reflects cost increases and the impact of the mergers of AIU. AIU believes the use of the 2005-2007 time periods to compare aggregate gas storage account costs is reasonable. AIU argues that using Mr. Lounsberry's analysis, one could pick an individual account in the test year with a lower than average balance and determine that an increase is actually required rather than a decrease.

b. Staff's Position

Mr. Lounsberry recommends a reduction of \$25,000 to AmerenCILCO's requested test year amount for Account 830. He explains that AmerenCILCO's test year expense was the second highest expense over the 5 historical years reviewed and that AmerenCILCO's expenses associated with this account varied significantly during the 5 historical years. He also recommends a reduction of \$54,000 to AmerenCILCO's requested test year amount for Account 834. AmerenCILCO requested \$89,000 as its Account 834 test year amount, which Staff notes was the highest expense over the five historical years reviewed and that expenses associated with this account varied significantly during the 5 historical years.

Mr. Lounsberry does not agree with AIU's assertion that the aggregation of the gas storage accounts demonstrates the reasonableness of any individual account. In order to provide a complete review, however, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Instead of limiting that review to the 3-year period that AIU used, Mr. Lounsberry actually used the full 5 years' of historical information that he had relied upon in making his initial adjustment. According to Staff, the combined gas storage accounts revealed that the total expenses were as follows:

2003	\$ 909,000
2004	\$ 888,000
2005	\$1,463,963
2006	\$1,419,581
2007	\$1,151,275

Staff states that the years 2005 and 2006 had the highest aggregate totals by a significant amount. Therefore, Staff concludes that the aggregate accounts supports Mr. Lounsberry's proposal to reduce AmerenCILCO's Account 830 test year expense amount by \$25,000. Staff also believes the aggregate of the accounts supports Mr. Lounsberry's proposal to reduce the Account 834 expense amount by \$54,000.

AIU argues that use of the 2005-2007 data for the combined storage accounts is more current and therefore more representative of the expected on-going costs because it reflects cost increases and the impact of the AIU mergers. AIU also asserts that the O&M expense for gas storage is relatively stable over time and that the variances over the years to an account like Account 830 represent shifts in expenditures between accounts, but not an overall increase in O&M expense.

Staff says it analyzed the individual Account 830 costs over the period from 2003-2007. Staff claims this analysis demonstrates that at least for Account 830, the 2005-2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year. According to Staff, the expenses over the 2003-2007 time period were as follows:

2003	\$ 8,000
2004	\$65,000
2005	\$34,000
2006	\$58,000
2007	\$0
Average	\$33,000

In Staff's view, AIU did not demonstrate why the proposed test year amount for Account 830, \$58,000, would be just and reasonable.

Similarly, Staff believes the Account 834 costs information for the years 2005 - 2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year:

2003	\$ 3,000
2004	\$20,000
2005	\$29,000
2006	\$89,000
2007	\$33,000
Average	\$34,800

According to Staff, AIU fails to demonstrate why the use of the year 2006 amount for Account 834, \$89,000, would produce just and reasonable rates.

c. Commission Conclusion

Having reviewed the record and the parties' arguments, the Commission finds Staff's proposed reductions to Accounts 830 and 834, of \$25,000 and \$54,000, respectively, to be appropriate. While AIU's argument that gas storage cost accounts should be reviewed in aggregate has some appeal, a 5 year average of the aggregate gas storage cost accounts might suggest a reduction of over \$250,000. In the

Commission's view, Staff's proposed reductions, while arguably conservative, are reasonable and should be adopted.

15. Gas Account 823 - AmerenIP - Hillsboro

a. Staff's Position

AmerenIP seeks to include in rates as an operating expense an annual inventory adjustment of \$1,439,000 at the Hillsboro Storage Field. Staff witness Lounsberry recommends that the Commission deny recovery of this amount. His primary reason for making this recommendation is his belief that AmerenIP, due to the various historic problems it has experienced at the Hillsboro field, can not yet reliably make use of the reservoir information to determine any needed adjustments to the field's inventory.

Mr. Lounsberry states that one of the primary means that a utility has to oversee the operation of its storage field involves comparing the field's inventory to the pressure of the gas in the field. He claims that AmerenIP's failure to operate the Hillsboro field with a constant inventory volume since the field was expanded in 1993 causes a situation where the use of normal oversight practices is not reliable. Staff asserts that this concern is shared by AmerenIP. Staff cites a November 20, 2006 report that Staff says, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. According to Staff, AmerenIP personnel estimated that after three years of cycling the reservoir at a constant working gas volume, the reservoir would stabilize and the hysteresis curve will be helpful in quantifying gas loss volumes.

AIU argues that in 2006, AmerenIP developed an engineering estimate of the magnitude of losses at Hillsboro. AIU reports that this estimate showed that 200,000 Mcf was appropriate to maintain Hillsboro performance. Subsequent to developing the 2006 estimate, AIU states that AmerenIP conducted additional analysis in 2007 that verified the 2006 estimate was appropriate. According to Staff, in making this latter calculation, called the Tek Methodology, AmerenIP compared the total gas in the reservoir at the end of the 2001 withdraw season to the total gas in the reservoir at the end of the 2006 withdraw season. This calculation was then divided by 5 (for five seasons between the values) and showed a loss amount of 2.29 Bcf, or a loss of about 460,000 Mcf per cycle, or roughly double the 200,000 Mcf loss correction AmerenIP calculated. AIU also indicates that the same calculation was made between 2001 and 2008 and showed about a 340,000 Mcf gas loss per cycle.

Mr. Lounsberry believes that AmerenIP is making its conclusion based on data that compares data points for a time period when the Hillsboro field's inventory was greatly reduced to a more recent period for when Hillsboro had additional inventory. Staff believes the timing of AmerenIP's calculation is causing it to rely upon an apples-to-oranges comparison rather than a comparison that would take place once AmerenIP replaced the inventory in the Hillsboro field. Staff notes that AmerenIP's calculation compared 2001 to 2006 data as well as 2001 to 2008 data. Staff states that AmerenIP

had previously concluded that the inventory balance that it maintained at the Hillsboro field was overstated by 5.8 Bcf as of November 30, 2003. AmerenIP replaced this inventory over a 3-year period, 2003-2005. Staff says AmerenIP also claimed to have found a 1.1 Bcf error that it returned to the Hillsboro field during the 2007 injection season. Therefore, Staff argues, AmerenIP is using inventory numbers for 2001 that bear no relationship with either the 2006 or 2008 values due to the extremely large amounts of gas replaced during the intervening period.

Staff also contends that in 2001, the Hillsboro field was not even functioning properly. Staff states that AmerenIP had reduced the peak day capacity rating of the Hillsboro field to 100,000 Mcf per day from 125,000 Mcf per day. Staff also says that due to the inventory shortfall, the Hillsboro field could only produce a fraction of the seasonal quantities it was designed to produce, 2,916,351 Mcf instead of 7,600,000 Mcf or 38.37% of its design total. According to Staff, AmerenIP's attempt to use 2001 data for comparative purposes does not make sense and should be disregarded.

AIU agrees that AmerenIP's comparison occurred during periods when inventory was reduced. AIU also provides the same Tek Methodology analysis, but limited it to comparing the 2006 to 2008 time period. AmerenIP claims this second comparison is generally in agreement with the original 2001 to 2006 comparison. AmerenIP insists that this analysis supported its decision to add about 200,000 Mcf of inventory to the Hillsboro field in 2006.

Staff maintains that the calculation comparing 2006 to 2008 information, still did not account for the 1.1 Bcf that was added into the Hillsboro field inventory in 2007. Staff also states that AmerenIP's analysis relies upon the gas volume in the field at the end of the withdrawal cycle. According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields. Staff argues that, in general, warmer weather creates a situation where more gas is remaining in the field than the utility had planned. Mr. Lounsberry says the 2006 test year conditions were warmer than normal. Staff claims AIU also agrees that winter season temperatures can impact the level of gas that it can withdraw from storage. Staff complains that AmerenIP's calculation does not take into account any temperature conditions. In Staff's view, AmerenIP's analysis is overly simplistic and limited for use at a storage field that has not experienced significant historical inventory losses. Staff does not believe AmerenIP's analysis provides a conclusive demonstration of the need for an annual inventory adjustment at the Hillsboro field.

Mr. Lounsberry also expressed concern that AmerenIP had never determined the need to make an annual inventory adjustment for the Hillsboro field prior to the 2006 test year. His concern is that there was no history of a similar expense and thus no history of a need to make an annual inventory adjustment at the Hillsboro field. AIU agrees that 2006 was the first occasion an annual inventory adjustment was made to Hillsboro, although AIU claims to have made inventory adjustments for a number of years at other storage fields. AIU states that AmerenIP intends to make a similar adjustment for Hillsboro in 2007.

Staff notes that AmerenIP has recently replaced a significant amount of gas at the Hillsboro field. Staff says AmerenIP's replacement gas represents 96% of the gas volume that the Hillsboro field was designed to withdraw during the winter season. Mr. Lounsberry expresses concern that AmerenIP was not making use of the reservoir model that was discussed extensively during IP's last rate proceeding, Docket No. 04-0476. Staff is concerned that such a valuable resource was not used as part of AmerenIP's calculations in this proceeding, especially given the time and money spent to develop this model. Mr. Lounsberry expected AmerenIP to make use of it to develop or support inventory numbers versus calculations based on comparing inventories between two inconsistent time periods. AIU claims the model was not available to evaluate Hillsboro because in 2005, AmerenIP made the determination to not further pursue modeling until a complete metering data set had been established in the reservoir simulator. AmerenIP did not begin to rebuild this database in preparation for resumption of modeling the reservoir until the summer of 2007. Staff complains that it is not clear why AmerenIP was unable to update the metering data set in a more timely fashion.

According to Staff, AmerenIP suggests that Mr. Lounsberry's recommendations are inconsistent with prior proceedings, Docket Nos. 03-0699 and 04-0677, wherein Staff noted that IP should have begun replacement of inventory at the Hillsboro storage while continuing to pursue its investigation as to the cause of the inventory shortfall. Staff says that in those proceedings it argued that had IP been aware of that error in a more timely fashion, it should have replaced some of that known inventory shortfall caused by the metering problem while continuing to investigate if the Hillsboro field had additional problems. Staff fails to see any connection between the instant proceeding and those prior cases. Staff claims that Mr. Lounsberry's testimony and the issue at hand is whether AmerenIP can justify the volume and value of the inventory adjustment that it wishes to make for the Hillsboro field.

b. AIU's Position

AmerenIP proposes an annual inventory adjustment to Account 823 of \$1,439,230 for the Hillsboro Storage Field ("Hillsboro"). The adjustment represents AmerenIP's determination to inject additional gas at Hillsboro. AmerenIP claims the proposed adjustment is conservative and based on the best data available to the AmerenIP.

In 2006, AIU states that AmerenIP developed an engineering estimate of the magnitude of gas losses at the Hillsboro field. The results of the estimate indicated that a 200,000 Mcf injection of gas was appropriate in 2006 to maintain Hillsboro's performance. Subsequent to developing the estimate, AIU indicates that in 2007 AmerenIP conducted an additional analysis, using information obtained during the next inject/withdraw cycle, verifying that the estimate it used in 2006 was supportable and prudent. According to AmerenIP, the engineering principles utilized for the 2007 analysis included the Tek Methodology, an analysis of the hysteresis plot for the field,

and a review of field withdrawal performance. AIU claims these are all commonly accepted gas storage reservoir engineering practices.

An additional analysis of reservoir performance, AIU adds, was performed in the spring of 2008 to investigate what impact the injection of additional gas has had on the delivery performance of the Hillsboro field. For this analysis, AmerenIP re-estimated gas loss using the Tek Methodology. According to AmerenIP, the decrease in estimated gas loss from the 2001 to 2005 analysis and the 2001 to 2008 analysis indicates that the 200,000 Mcf gas loss adjustments that were made in 2006 and 2007 have had a positive impact on maintaining reservoir deliverability. In AIU's view, these analyses showed that AmerenIP's 200,000 Mcf estimate of the gas loss is reasonable and prudent.

AIU argues that there is no dispute that the lost gas should be replaced and Staff does not suggest otherwise. AIU contends that AmerenIP's analysis of the data supports the amount of gas loss and the need for replacement, based on the Tek Methodology. ReInjection of gas to replace lost gas before completion of a thorough engineering analysis of the reservoir response is, AIU claims, consistent with Staff's position in past cases. According to AIU, without the reinjection of the lost gas, field performance at Hillsboro would be at risk, and the field might not be able to cycle the gas required to best meet customer needs. AmerenIP expects that Hillsboro deliverability would decline by approximately 200,000 Mcf per year without reinjection, impacting daily deliverability at the year end. AmerenIP claims that not reinjecting could also cause increased water production and possibly increased H₂S production, further decreasing the reliability of the field. AIU says these factors would ultimately be reflected as a higher cost for ratepayers.

Staff opposes the annual inventory adjustment based primarily on concerns about the reliability of the data supporting the adjustment. Staff believes that AmerenIP does not have sufficiently reliable information about Hillsboro, and can not perform the necessary engineering studies to quantify the gas loss. AIU says Staff recommends doing nothing at this time to address the gas loss issue. AIU maintains that inaction would not be appropriate. AIU believes that AmerenIP should take steps to address the performance of underground fields, such as injecting replacement gas, to maintain reliable service from its storage fields. AIU relates that AmerenIP has calculated annual inventory losses supporting the inventory adjustment at Hillsboro.

At Hillsboro, AIU and Staff acknowledge that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis using hysteresis techniques. AIU asserts that any correction must be based on an engineering estimate, or rely on other sound engineering principles and practices other than hysteresis techniques. AIU asserts that AmerenIP is not required to support its adjustment on a specific type of analysis just because Staff would prefer it. AIU claims that AmerenIP properly relies on the available data, which reasonably supports the adjustment.

AIU argues that Staff's position on the deterioration of storage field performance is inconsistent with a disallowance of an annual inventory adjustment for Hillsboro. AIU asserts that on the one hand Staff supports injecting additional gas to maintain reservoir performance, but on the other hand disallowing the cost of the actions taken by AmerenIP to maintain that performance. It is AIU's opinion that AmerenIP has utilized the best data that is available to make a sound engineering judgment regarding the Hillsboro lost gas adjustment and AmerenIP has taken proactive steps to maintain the field's deliverability.

According to AIU, Staff has recommended, in previous proceedings, that a gas utility take action to correct an inventory shortfall even when data is not complete. AIU says that in Docket Nos. 03-0699, 04-0677, and 05-0743, Mr. Lounsberry argued that IP did not act fast enough to replace the gas at Hillsboro that was no longer in the field. In those cases, AIU says Mr. Lounsberry's position was that the utility should have been replacing inventory while continuing to pursue its investigation as to the cause of the inventory shortfall. In this case, Mr. Lounsberry states that AmerenIP should not use available data to proceed to make an adjustment, even though AmerenIP has calculated its inventory adjustment based on the best available data and is continuing to gather data to improve the estimate.

With regard to Staff's specific concerns, AIU believes these have been adequately addressed. In response to Staff's concern that comparing 2001 data to 2008 data is not appropriate, AIU says that AmerenIP undertook an analysis using data from 2006 - 2008 instead of comparing to 2001. AIU claims the results of this analysis were consistent with the analyses comparing 2001 to 2006 and 2008, and showed that there is an annual gas loss occurring at Hillsboro of slightly less than 0.5 Bcf per year. According to AIU, the original calculations utilizing a 2001 data comparison indicate that from the time period from 2001–2006, the gas loss was 468,000 Mcf per year and from 2001–2008, the gas loss was 337,000 Mcf. AIU insists that AmerenIP is justified in making a conservative adjustment of 200,000 Mcf per year.

AIU reports that the Hillsboro field cycled 6.7 Bcf of gas in 2005–2006 and 6.6 Bcf in 2007–2008. AIU claims that if AmerenIP had not injected an additional 200,000 Mcf during the 2006 and 2007 injection seasons, it is reasonable to assume AmerenIP would not have been able to withdraw roughly equal amounts of gas during the two seasons that are compared.

Mr. Lounsberry also opposes the annual inventory adjustment at Hillsboro based on the concern that annual adjustments were not made before the 2006 test year, raising concern that there is not a history of similar expenses for Hillsboro. AIU states that Mr. Lounsberry is correct that 2006 is the first occasion that an inventory correction was made to Hillsboro in recent history. AIU claims that AmerenIP has made corrections to storage field inventories on an as-needed basis for many years and has performed inventory corrections on an ongoing basis. In AIU's view, the fact that the first correction at Hillsboro occurred in 2006 does not mean the adjustment is not just and reasonable.

According to AIU, Mr. Lounsberry is correct that the reservoir model would be an appropriate method to determine gas losses. AIU says the reservoir simulator was not available to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections from 2000-2007. AIU adds that in 2005 the determination was made not to further pursue modeling until a complete metering data set had been established for the reservoir simulator. AIU states that in the late summer of 2007 AmerenIP began to rebuild the database in preparation for resumption of modeling of the reservoir and that project is still in progress. AIU contends that because the model was not available, other sound engineering techniques were used to determine the gas loss. After the revised data deck is built, AIU states that AmerenIP will model the reservoir and present the results to Staff. AmerenIP recognizes that it is proceeding with modeling utilizing adjusted data, rather than actual field data, but insists the adjusted data is sufficient to support the annual inventory adjustment.

c. Commission Conclusion

AmerenIP proposes an annual inventory adjustment to Account 823 of \$1,439,230 for the Hillsboro Storage Field. AIU insists the proposed adjustment is conservative and based on the best data available. AIU contends further that the fact that Staff would prefer some other type of data or study to support the adjustment is not a basis for rejecting the adjustment. Staff's primary reason for opposing the adjustment is due to the various historic problems AmerenIP has experienced at the Hillsboro field. Staff does not yet believe that AmerenIP can reliably make use of the reservoir information to determine any needed adjustments to the inventory at the Hillsboro field.

The Commission again observes that this issue is similar to two issues previously addressed regarding lost gas at the Hillsboro field. In the other two instances, AmerenIP asserts that there has been lost base gas, it has estimated the volume of lost gas, and requests authorization to include the additional base gas in rate base. In this instance, AmerenIP asserts there is lost gas at Hillsboro, it has estimated the volume of lost gas, and it wishes to recover the cost of replacing the lost gas through operating expenses. In all three instances, Mr. Lounsberry objects to AmerenIP's request. Mr. Lounsberry again insists, among other things, that AmerenIP has failed to adequately demonstrate that its estimate of the volume of lost gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, as well as for the two previous lost gas issues in this case, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost gas is reasonable. As a result, the Commission adopts Staff's recommendation and AmerenIP's request to recover the replacement gas through Account 823 is denied. In the Commission's view, these three decisions regarding lost gas at Hillsboro are consistent with, and are required by, the appellate court decision discussed earlier in this Order.

16. Gas Accounts 920-923 - AmerenIP

a. The AG and CUB's Position

The AG and CUB propose an adjustment to reduce the pro forma AmerenIP A&G expenses by \$7,736,000. In analyzing the expenses associated with the general administration of operations, AG/CUB witness Effron believes that it is appropriate to consider expenses charged to Account 923 "Outside services employed" together with expenses charged to Accounts 920-922, which are compensation to management employees and other expenses of administrative departments. Mr. Effron testifies that expenditures charged to Account 923 for outside professional services can be similar in nature, except the expenditures are to persons who are not employees. For example, salaries of attorneys or engineers who are employees would be charged to Account 920, while expenditures on outside attorneys or engineering consultants would be charged to Account 923. In both of these cases, the AG and CUB say the expenses relate to the administration of the operations of AIU and, to some extent, may be interchangeable. Mr. Effron proposes to adjust AmerenIP's gas test year A&G expenses charged to Accounts 920-923.

The AG and CUB point out that in 2004, the test year in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the pro forma expenses included in Accounts 920-923 by AmerenIP were \$22,259,000. The Commission eliminated approximately 30% of the AmerenIP A&G expenses from the revenue requirement in that case. The AG and CUB say the Commission's A&G adjustment was not broken out by account, but assuming that the adjustment was spread evenly over all the A&G accounts, the AmerenIP revenue requirement in its last rate case reflected an allowance of \$15,476,000 charged to Accounts 920-923.

The AG and CUB claim the A&G expenses charged to Accounts 920-923 in the 2006 test year in the present case significantly exceed the expenses found to be reasonable by the Commission in AmerenIP's last rate case. Thus, the AG and CUB believe that the expenses allowed by the Commission in the prior rate case form a reasonable basis for A&G expenses to be included in the AmerenIP revenue requirement in this case. Thus, Mr. Effron's recommendation is to reduce the pro forma AmerenIP A&G expense by \$7,736,000 as reflected in AG/CUB Ex. 4.0 at 9-10.

b. AIU's Position

AIU believes an adjustment to the A&G expense is not warranted. AIU asserts that Mr. Effron's methodology for determining his proposed adjustment to the A&G expense is flawed. AIU witness Adams explains that, in calculating his adjustment, Mr. Effron uses as a starting point the level of A&G expenses charged to Accounts 920 through 923 approved by the Commission in AIU's last gas rate cases, which used a 2004 test year. Mr. Effron calculates this amount by taking the total of A&G costs related to Accounts 920 through 923 times the percentage of costs that were disallowed. AIU says he then escalates this last approved level of A&G expenses

charged to Accounts 920 through 923 by 3% per year to reflect inflation. The end result of Mr. Effron's initial adjustment is the proposed disallowance of \$19,794,000 of A&G expenses for AmerenIP. AIU says this is the difference between the amount approved in the last rate case, escalated by inflation, and the expenses included by AmerenIP in this case, for Accounts 920 through 923.

AIU argues that the Commission has rejected the notion that inflation between rate cases is a better indication of test year expenses than the actual costs themselves. AIU says Mr. Adams' rebuttal testimony explains the modification of accounting practices implemented after the acquisition of IP by Ameren. AIU points out that thereafter, Mr. Effron reduces his proposed adjustment by \$7.7 million. AIU claims the actual level of AmerenIP's A&G expenses have been fully justified between the AMS study which Mr. Adams sponsored and through his testimony on the topic of A&G expenses.

AIU claims Mr. Adams explains that the comparison of the level of expenses between 2004 and 2006 for AmerenIP produces specious results because during the transition of ownership, AIU received no allocated costs from either its former owner or from AMS. Therefore, AIU asserts that the true cost of services provided is not reflected in the 2004 expense levels.

c. Commission Conclusion

The AG and CUB are correct in asserting that the A&G expenses authorized by the Commission for Accounts 920-923 in the 2004 test year are significantly different than those requested by AIU for the 2006 test year in the present case. However, it appears that the AG and CUB do not adequately consider various changes that have occurred, which may have contributed to an increase in the A&G expense from the last rate case. AIU also provided the Commission with an AMS cost study detailing the test-year 2006 A&G expenses, which the Commission must consider in this case. In addition to inflation, which the Commission believes is a relevant factor, actual costs must also be considered, and AIU has supplied evidence regarding actual costs. Lastly, the Commission believes that the AG and CUB's proposed disallowance does not take into account the effect of the merger when comparing test-year expense calculations, which is significant. The Commission finds that in this case, using an inflation based adjustment to AmerenIP's Account 920 through 923 amounts authorized in the last rate case is inappropriate and must be rejected.

D. Approved Operating Income/Revenue Requirement

Upon evaluating the effects of the determinations made above, the operating statements for AIU's respective service territories for electric and gas delivery services are approved as shown in the Appendices attached hereto.

VI. COST OF CAPITAL/RATE OF RETURN

A. Introduction

A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type of capital affects the overall or weighted average cost of capital, which is the rate of return a utility is authorized to earn on its net original cost rate base.

The Commission relies on the cost of capital standard to determine a fair rate of return. This cost, which can be determined from the overall rate of return or weighted average cost of capital, should produce sufficient earnings and cash flow when applied to the respective company's rate base at book value to: enable a company to maintain the financial integrity of its existing invested capital, maintain its creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable a company to continue to meet the needs of its customers.

These standards are effectively mandated by the landmark U.S. Supreme Court decisions Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944) ("Hope"). Meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holders and equity holder alike.

B. Capital Structure

1. Common Equity Balances

AIU accepted Staff witness Phipps' miscellaneous adjustments to AIU's common equity balances, including, removal of the unappropriated undistributed subsidiary earnings balance from each utilities' common equity balance, removal of Ameren Energy Resources Generating's Accumulated Other Comprehensive Income (-OCI") from AmerenCILCO's common equity balance, as well as removal of the preferred stock premiums from AmerenIP's common equity balance.

AIU's and Staff's agreed common equity balances for AmerenCILCO and AmerenCIPS are \$217,459,214 and \$506,691,386; each as of June 30, 2007. AmerenIP's agreed December 31, 2006 common equity balance equals

\$1,076,124,965. The Commission finds these common equity balances appropriate and they will be adopted for this Order.

2. Preferred Stock Balances

Staff accepts AIU's proposed June 30, 2007 preferred stock balances for AmerenCILCO and AmerenCIPS. Staff and AIU agree on AmerenIP's December 31, 2006 preferred stock balance. Those agreed upon preferred stock balances are \$36,450,067 for AmerenCILCO; \$48,974,984 for AmerenCIPS; and \$45,786,945 for AmerenIP. The Commission finds that these balances are appropriate and they will be adopted for this Order.

3. TFTN Balance-AmerenIP

Staff and AIU agree that AmerenIP's December 31, 2006 TFTN balance equals \$171,533,494. The Commission finds this amount appropriate and will adopt it for this Order.

4. Short-Term Debt Balances

a. AIU's Position

AIU notes that Staff's position is that cash should not be netted against short-term debt to obtain the proper net short-term debt balance. Ms. Phipps argues that netting cash against short-term debt as part of the calculation of the proper amount of short-term debt –is improper because cash is not a part of short-term indebtedness." AIU submits that the proper analysis is whether the capital structure accurately reflects the mix of debt supporting utility assets. AIU is of the opinion that the principal flaw with Staff's approach is that, by failing to net cash against short-term debt, Staff treats cash as a utility asset, serving utility purposes, but then does not include the cash in rate base. AIU submits that this produces a mismatch between the cost of funds supporting assets and the returns those assets earn.

AIU avers that it is holding relatively high cash balances due to AIU's credit standing in the aftermath of the legislative "crisis" involving the 2007 retail electric rate changes, and that AIU requires these cash balances for operating purposes. AIU notes that the cash balances sit in money market accounts, earning standard money market returns, to assure immediate access to the funds. AIU submits that were its credit position better, AIU would not hold cash balances at these levels, and that the utilities are holding these amounts of cash to satisfy their public utility service obligations. AIU claims it has lost same day access to funds and instead has had to rely on bank facility borrowings, which requires a three business day lead time and generally involves a minimum loan term of 30 days, and submits that this has had a considerable effect on the flexibility of managing cash.

AIU is of the opinion that there are two ways to treat the cash balances being held for utility purposes. One is to maintain them entirely outside of the ratemaking process by deducting them from the short-term debt balances, as AIU did. AIU submits that this produces a return on the cash (the money market interest rate) reasonably comparable to (although still less than) its cost (the short-term debt rate). A second alternative, in AIU's opinion, would be for the cash to be included in rate base, and the short-term debt be fully reflected in the capital structure. AIU avers that this approach could produce an excess return, however, because the cash would be earning both the overall cost of capital in rates, plus the money market return. AIU submits that it did not pursue this approach, because of this mismatch of cost and return.

AIU is of the opinion that Staff has elected a third method, which produces a significant mismatch between the cost of financing and the return on the assets being financed. AIU notes that Staff includes the full amount of short-term debt (other than money pool lendings and CWIP) in the utility capital structure, while simultaneously treating the cash as a non-utility asset. AIU submits that this treatment assumes that the cash is supported by a mix of capital equal to the proportion of capital supporting assets in rate base. AIU claims that this results in a conclusion that AIU would raise cash at a cost of roughly 8% and invest it in money market accounts earning roughly 3%. AIU submits that this is not a reasonable treatment proposed by Staff.

AIU argues that, by differentiating between (1) cash on hand funding loans to sister utilities and (2) cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios. AIU submits that in reality only a cash management decision differentiates the two, and in both instances, the cash is earning a return elsewhere, and the cost of capital supporting the cash should be consistent with the return.

AIU opines that this same reasoning is consistent with that used in discerning that short-term debt related to CWIP and loans to the money pool should not be included in the capital structure. AIU submits that the same short-term debt funds can not be used simultaneously to support rate base and fund CWIP or be loaned to sister utilities and that this is consistent with Staff's long-standing practice and Commission precedent.

AIU further argues that Ms. Phipps, in her calculation of the twelve-month average of short-term debt, improperly aligns the midpoint of the twelve months with the measurement date of the long-term capital structure components. AIU also submits that Ms. Phipps uses data that goes beyond this measurement date by up to six months. AIU opines that short-term debt balances are the result of costs during the test year/measurement period and that the use of measurement balances beyond this period results in a measurement mismatch between short-term debt and the other capital structure balances. AIU avers that Ms. Phipps must provide more compelling evidence that use of data within the boundaries of the test year/measurement period is not proper. Although the Commission ultimately sided with Staff and this approach in

the most recent case, AIU submits that the language of the ruling was hardly a mandate.

While Staff argues that if a company's cost of capital is constant, short-term debt would not be used to finance cash, AIU submits that all of the components of the capital structure cost more than a company would earn on its cash investments. AIU posits that the cost of debt does not change just because the assets it supports earn a lower return, the cost of debt is set by the governing debt instrument.

AIU notes that while Staff suggests that cash is supported by low-cost equity capital, there is no suggestion where AIU is obtaining low-cost equity at a rate less than the short-term debt rate. AIU posits that Staff is tying cash to equity and only equity, while AIU avers that there is no way to isolate equity and apply it only to cash.

AIU opines that it has shown that the cash is being held for utility purposes, and if the cash is not netted against short-term debt to make it whole, then the cash should be included in rate base. While Staff argues that cash investments already earn a return commensurate with their risk, AIU suggests the problem is that the cash is not earning a return commensurate with its cost.

b. Staff's Position

Staff witness Phipps calculated the following short-term debt balances for the AIU: \$82,500,351 for AmerenCILCO; \$75,752,646 for AmerenCIPS; and \$82,506,936 for AmerenIP; while AIU witness O'Bryan proposed the following short-term debt balances: \$15,865,875 for AmerenCILCO; \$11,902,241 for AmerenCIPS; and \$47,106,782 for AmerenIP. Staff submits that AIU's calculations are flawed because Mr. O'Bryan: 1) used a measurement period that is not centered on the measurement date for long-term capital components, and 2) netted out all cash from short-term debt.

Staff notes that Ms. Phipps adjusted AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term debt measurement periods to have a midpoint that coincides with the measurement date for long-term capital structure components (i.e., June 30, 2007 for AmerenCILCO and AmerenCIPS; December 31, 2006 for AmerenIP), which she alleges better aligns the average balance of short-term debt with the long-term capital structure components. Ms. Phipps opines that the balances of short-term debt and long-term capital structure components can be perfectly aligned only if both are measured on the exact same dates, which would mean measuring the short-term and long-term capital structure component balances either on the same, single date, or as an average of the same 12-month period. She avers that the former has the disadvantage of not smoothing out the variation that often exists in short-term debt balances, while the latter has the disadvantage of being more time consuming and prone to measurement error due to the greater amount of data and calculations involved. Ms. Phipps submits that a reasonable, practical solution to those disadvantages is to measure the long-term capital components on a single date, while

smoothing out the variation in short-term debt by using a 12-month average centered on the measurement date of the long-term capital structure components.

Staff notes that while Mr. O'Bryan argues that Staff's measurement period results in a measurement mismatch between balances of short-term debt and the other capital structure components, Mr. O'Bryan's argument is not pertinent in this case because there were no issuances, redemptions or maturities of equity or debt during those six months beyond AIU's long-term capital measurement dates, which would be included in Staff's measurement period but not AIU's.

Staff opines that a 12-month average centered on the measurement date of AIU's long-term capital structure components minimizes the total number of months that are misaligned. Staff submits that using its methodology, the total misalignment between long-term and short-term capital balances is 42 months, while using AIU's methodology results in a misalignment of 78 months. Staff argues that because the number of months of misalignment in AIU's calculation is greater than Staff's calculation, any measurement mismatch affects AIU's calculations more than it would Staff's.

Staff notes that the Commission adopted Staff's short-term debt balance calculations in Docket Nos. 99-0534, 01-0696, 03-0676/03-0677 (Cons.) and 06-0070/06-0071/06-0072 (Cons.). Staff also cites the Commission's Order in Docket No. 01-0696.

While Staff notes that Mr. O'Bryan argues that short-term debt balances are the result of costs during the test year/measurement period, Staff submits that Mr. O'Bryan's argument is based on the faulty premise that the terms —testyear” and —measurement period” are synonymous. Staff notes that 83 Ill. Adm. Code 285.115 specifies that the capital structure measurement period refers to the period or point in time in which all long-term components of the capital structure are measured and may differ from the —test year.” Staff further notes that AIU chose June 30, 2007 to measure the balances of long-term debt, preferred stock and common equity for AmerenCILCO and AmerenCIPS, which is six months after the end of the 2006 test year.

Staff submits that the Commission's Order in Docket No. 99-0534 distinguishes between the terms capital structure measurement period and test year when it states:

. . . the cost of capital, and therefore its components, are not subject to the Commission's test year rules. In Business and Professional People for the Public Interest et al. v. The Illinois Commerce Commission et al., 585 N.E.2d 1032, (December 16, 1991), the Supreme Court found, in part, that, "Because the post--in--service carrying charges are not operating expenses, they are not test--year items. Therefore, we agree with Edison and the Commission that recovery of deferred financing charges does not violate test--year principles." (BPI II at 1060) The implication of the Court's finding is that the balance of short-term debt, as a component of a utility's

authorized rate of return, is not subject to test--year rules. (Docket No. 99-0534, Order at 32-34 (July 11, 2000))

Staff argues that another flaw in Mr. O'Bryan's analysis is his subtraction of cash from each month-end gross short-term debt balance, which Ms. Phipps testified is improper because cash is not a part of short-term indebtedness. Staff's short-term debt calculation does not net out cash; however, it does reduce monthly gross short-term debt balances for each of the Companies by an amount equal to its month-end balance of bank loan contributions to the Ameren utility money pool.

Staff submits that while cash is fungible and can not generally be traced from source to use, nevertheless, a portion of AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term balances appear to coincide with contributions to the Ameren utility money pool. Staff takes the position that in those instances where there is a clear, proximate connection between a company's short-term debt balance and its contributions to the utility money pool, it is appropriate to net money pool contributions out of gross short-term debt to avoid double counting bank loans from Ameren's credit facilities. Staff submits that this ensures that those contributions (which are included in the borrower's short-term debt balances) are not counted twice in both the lender and the borrower's capital structure.

Staff asserts that Mr. O'Bryan's reasoning is faulty in that it implies the cost of capital remains constant regardless of the riskiness of the assets it supports. Staff posits that the costs of the various sources of financing are a function of the riskiness of the assets being financed as well as the amount of debt used to finance the assets. Staff submits that Mr. O'Bryan's rationale suggests that holding the capital structure constant, a company's cost of capital would be the same whether its assets wholly comprised U.S. Treasury bills, electric distribution plant, or oil drilling equipment.

Staff posits that if this held true, companies would not have any cash on their balance sheet unless they also had short-term debt outstanding because it would perforce be financed with —high cost” long-term debt and equity. Staff submits this is not true for AIU. Staff notes that during 2006, from January through November, AmerenCIPS' month-end short-term debt balances were zero; yet, during the same period, AmerenCIPS' month-end cash balances ranged from \$0.5 million to \$62.5 million. Staff further notes, on May 31, 2007, AmerenCIPS had no short-term debt outstanding and a \$44 million cash balance.

Contrary to Mr. O'Bryan's opinion that AIU's capital must be tied to the assets included in rate base, Staff submits that the Commission has recognized that, for ratemaking purposes, a utility's capital structure is not required to equal rate base, but rather, a utility's capital structure must reflect the mix of capital a utility relies upon to finance its rate base. Specifically, in the prior CIPS and UE gas rates proceeding, the Commission's Order states:

On a utility's financial statements, the total dollar value of assets must equal the total dollars of liabilities and owner's equity. In a rate case, however, the total dollars of jurisdictional rate base does not necessarily equal total capitalization Due to the fungible nature of capital, it is generally assumed that all assets, including assets in rate base, are financed in proportion to total capital

The Commission has reviewed the parties' arguments and adopts Staff's proposal for calculating the amount of short-term debt included in UE's capital structure. (Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 65-68 (October 22, 2003))

Staff disputes the notion that AIU is holding relatively high cash balances due to its credit standing in the aftermath of the legislative crisis involving the 2007 retail electric rate changes, and submits that AIU held substantial cash balances prior to March 2007, which is when its issuer credit ratings were downgraded to below investment grade. Staff notes that on March 31, 2007, AmerenCILCO's cash balance equaled \$200,000, and AmerenCIPS' cash balance equaled \$47 million, while during 2006, AmerenCILCO held cash balances as high as \$22 million and AmerenCIPS held cash balances as high as \$63 million, excluding loans to utility affiliates through the money pool. Staff further notes that AIU has never identified specific months or amounts that relate solely to its credit rating downgrades, and when the risk of an electric rate rollback and freeze disappeared, AIU's short-term debt balances either increased or stayed approximately the same.

Staff notes that while AIU argues that cash must be netted out of short-term debt balances, Staff submits that AIU's own actions demonstrate otherwise. Staff notes that during August 2006, AmerenCILCO, AmerenCIPS and AmerenIP had net cash balances of \$13 million, \$77 million and \$9 million, respectively. Staff further states that AmerenCIPS and AmerenIP paid common dividends totaling \$40 million and \$61 million, respectively, during 2007, rather than paying down short-term debt.

While AIU argues that failure to net cash against short-term debt implies that cash should be part of rate base, Staffs submits that cash does not need to be included in rate base because temporary cash investments already earn a return commensurate with their risk. Staff opines that including cash in rate base would increase the amount of the AIUs' rate base; and the rate base including cash would be relatively less risky than rate base excluding cash because there is virtually no risk associated with cash on hand. Staff submits that adding low risk cash to rate base assets would lower the cost of capital, which, combined with including the income on cash investments in the revenue requirement, would exactly offset the higher rate base.

Staff further notes that AIU takes the position that by differentiating between cash on hand funding loans to sister utilities and cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios.

Staff submits however, that in reality only a cash management decision differentiates the two.

Staff opines that if AIU's proposed adjustment was for the purpose specified, then such adjustment would have been limited to the period during which AIU built up cash reserves and would have adjusted short-term debt for only the portion of cash AIU alleges it accumulated during that period. Staff notes however, that instead, AIU proposes to subtract the entire cash balance from short-term debt during the entire short-term debt measurement period. Staff notes that for AmerenCILCO and AmerenCIPS, the AIU proposed short-term debt measurement period covers June 30, 2006 to June 30, 2007, for which only four monthly balances out of thirteen occur after the March 2007 credit rating downgrade, and for AmerenIP, the AIU proposed short-term debt measurement period ends three months before the downgrades occurred. Staff avers that under no circumstances would it be reasonable to remove all cash, as AIU proposes to do, since on any given date a utility would likely have cash on hand for operating purposes.

Staff submits that the two alternatives that AIU has offered for the treatment of short-term debt balances have one thing in common, each would result in higher rates charged to ratepayers. Staff recommends that its suggested short-term balances be adopted for the purposes of this Order.

c. Commission Conclusion

AIU argues that it is holding abnormally high cash balances due to each utility's worsened credit situation following the 2007 retail electric rate changes, and suggests that these cash balances should be netted out from short-term debt balances to compute the capital structure for each company. AIU suggests that a second alternative would be to include the cash in rate base, and the short-term debt be fully reflected in the capital structure; however, AIU argues this might produce an excess return for each company as they would be earning a money market rate of return on the cash while also earning the approved return on equity.

Staff takes the position that the total amount of short-term debt should be reflected in the capital structure and that cash balances should not be netted out from the balances. Staff notes that cash is fungible and generally can not be traced from source to use, however it appears to Staff that a portion of each utilities' short-term debt balances coincide with contributions to the Ameren utility money pool. Staff suggests where there is a clear connection between the short-term debt and its contribution to the money pool, it is appropriate to net those contributions out of short-term debt to avoid double counting. Staff disputes that AIU is holding relatively high cash balances solely due to its credit standing, and notes several instances where one of the utilities held high cash balances prior to the retail electric rate crisis and the downgrade in each utilities credit rating.

The Proposed Order in this proceeding adopted AIU's proposed short-term debt balances rather than Staff's proposed balances. In its Brief on Exceptions, Staff maintains that cash balances should not be subtracted from short-term debt balances and that its proposed measurement period for short-term debt balances should be adopted rather than AIU's proposal. Staff, however, also provided several alternatives for the Commission's consideration in the event it rejected Staff's primary position. Specifically, using data presented in Staff Group Ex. 3, Staff presented information that would allow the Commission to combine Staff's measurement period for short-term debt balances with Staff's measurement proposal, with AIU's measurement proposal, and with a measurement approach that would remove only "excess" cash balances from the short-term debt balances.

As an initial matter, it appears from the record that neither the AIU proposal nor the Staff primary proposal is perfect and that each has raised valid concerns or criticisms of the other. All things considered, the Commission believes that Staff's suggested approach to remove excess cash from short-term debt balances, along with the adoption of Staff's measurement period, appears to be the approach best supported by record evidence. Upon consideration of all the evidence presented, the Commission finds that AIU has not justified subtracting the entire cash balance during the entire short-term debt measurement period. The Commission finds convincing Staff's argument that, in no event, should all cash be subtracted from the short-term debt balances. The record clearly indicates that AIU used short-term debt for purposes unrelated to the requirements that it hold unusually high balances. Thus, the suggestion of removing the "excess" cash is the most reasonable. Staff also suggests that it would be inappropriate, considering AIU's loss of same-day access to funds, to potentially enrich AIU through a higher authorized rate of return due to its affiliates' decision, which AIU disputes, to withhold financial support. While the Commission is always observant of such possible actions, as theorized by Staff, it does not appear that the record nor the arguments presented by the parties have been fully developed in this proceeding. In any event, the Commission notes that this issue was not a significant factor in the Commission's decision on the appropriate amount of short-term debt to include in the capital structure for AIU.

It appears to the Commission that, at least for a portion of Staff's short-term debt measurement period, AIU has been keeping higher than normal cash balances due to its relatively low credit rating, which resulted from the perceived electric rate crisis. The Commission agrees with Staff's assertion that in no event should all cash balances be subtracted from the short-term debt balances. As such, the Commission is of the opinion that adopting Staff's calculation of short-term debt, which removes "excess" cash is superior to AIU's proposal to remove all cash from short-term debt, and it is adopted for purposes of this docket.

The final issue with regard to short-term debt balances is whether the average balances of short-term debt should be centered upon the capital structure measurement date as Staff recommends, or should end at the same date as the capital structure measurement period as AIU recommends. The Commission notes that AIU's proposed

short-term debt measurement period for AmerenIP ends three months before the March 2007 credit rating downgrades and, further, only a portion of AmerenCIPS' and AmerenCILCO's proposed measurement periods are after the credit downgrades. The Commission also notes that this issue is the same as that litigated in AIU's last rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)). The Commission has reviewed the record on this issue and again concludes that Staff's approach is superior to AIU's. The Commission notes that this issue is significant to the final calculation of the appropriate cost of equity. As illustrated by Staff's testimony, all else being equal, to use AIU's proposed measurement period in Staff's cost of capital recommendation, would cause the overall cost of capital to increase 54 basis points for AmerenCILCO, 20 points for AmerenCIPS, and 8 basis points for AmerenIP. The Commission also observes that in the South Beloit Water, Gas and Electric Company's rate case in Docket Nos. 03-0676/03-0677 (Cons.), the Commission adopted the approach advocated by Staff in this proceeding. The Commission will therefore adopt Staff's measurement period for calculating short-term debt balances in this proceeding. The conclusions reached in this portion of the order lead the Commission to adopt short-term debt balances of \$72,643,527, \$55,210,979, and \$76,677,769 for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

5. Long-Term Debt Balances

The Commission notes that Staff recommends the following long-term debt balances for AIU: \$141,064,706 for AmerenCILCO; \$446,741,385 for AmerenCIPS; and \$709,096,036 for AmerenIP; while AIU proposes the following long-term debt balances: \$141,064,013 for AmerenCILCO; \$445,904,162 for AmerenCIPS; and \$704,808,159 for AmerenIP. It appears to the Commission that despite the very minor differences between AIU and Staff, the resolution of this issue will be determined by the Commission decisions in the following parts of this Order; Embedded Cost of Long-Term Debt – AmerenIP, Embedded Cost of Long-Term Debt – AmerenCIPS, and Embedded Cost of Long-Term Debt – AmerenCILCO.

C. Cost of Debt

1. Short-Term Debt

AIU updated its cost of short-term debt to conform with Staff's calculations, and for purposes of this case, accepted Ms. Phipps' weighting methodology used to calculate the cost of short-term debt for AIU. This weighting methodology determined a spread over the London Inter-Bank Offer Rate index to calculate AIU's cost of short-term debt. The agreed upon costs of short-term debt are 4.04% for AmerenCILCO, 4.01% for AmerenCIPS, and 3.93% for AmerenIP.

IIEC witness Gorman recommended a reduction to AIU's cost of short-term debt. IIEC notes that AIU reduced its short-term cost to recognize more recent lower interest rates, and IIEC does not contest this issue further. The Commission finds the agreed

costs of short-term debt for each company to be appropriate, and they will be adopted for the purposes of this Order.

2. Variable Rate Long-Term Debt

AIU accepted Ms. Phipps' interest rates for AmerenCILCO and AmerenCIPS Series 2004 auction rate pollution control bonds ("PCBs"). Ms. Phipps used interest rates from the last auctions prior to the December 2007 rating agency actions that affected the bond insurers that insured these PCBs. This, in turn, had a negative effect on the interest rates of the PCBs. AIU submits that although this is a reasonable approach to treat the cost of these bonds, this approach should not be used with respect to the AmerenIP auction rate PCBs. The agreed upon interest rates are 4.10% for AmerenCILCO's \$19.2 million auction rate PCBs and 4.25% for AmerenCIPS' \$35 million auction rate PCBs. The Commission finds these rates to be appropriate, and they will be adopted for the purposes of this Order.

3. Embedded Cost of Long-Term Debt for AmerenCILCO

For AmerenCILCO, Staff witness Phipps calculated a 6.65% embedded cost of long-term debt while AIU calculated a 6.67% embedded cost of long-term debt. The difference between those calculations relates to the annualized interest expense for AmerenCILCO's auction rate PCBs. AIU accepted Staff's proposed 4.10% rate for AmerenCILCO's auction rate PCBs, but Staff notes that AIU failed to update its long-term debt schedule to reflect Staff's proposal. As such, Staff believes the Commission should adopt Staff's calculation of AmerenCILCO's embedded cost of long-term debt, as presented in Staff Ex. 4.0R, Sch. 4.03 CILCO. AIU indicates it does not contest Staff's long-term debt rate for AmerenCILCO. The Commission finds Staff's suggested embedded cost of long-term debt for AmerenCILCO to be appropriate and it will be adopted for the purposes of this Order. The Commission understands that as a result, the proper balance of long-term debt to be adopted for AmerenCILCO is \$141,064,706, as Staff recommends.

4. Cost of AmerenIP's Transitional Funding Trust Notes

a. AIU's Position

AIU witness O'Bryan employed an internal rate of return ("IRR") method to determine the embedded cost of the AmerenIP TFTN. AIU opines that the IRR method is appropriate for determining the cost of this debt because AmerenIP does not have economic use of the entire amount of net proceeds of the TFTN between the issuance date (December 1998) and the final maturity date (December 2008). AIU submits that the use of the IRR method to determine the cost of TFTNs was approved by the Commission in the 1999 and 2001 electric delivery services tariff cases as well as the 2004 gas rate case.

AIU argues that Staff witness Phipps incorrectly suggests that the TFTN coupon rate should not be calculated using an IRR monthly compounded methodology. AIU submits that Ms. Phipps' argument to annualize the monthly discount rate by multiplying the rate by twelve is based on the faulty assumption that the Instrument Funding Charges ("IFC") collections are remitted by AmerenIP to the indenture trustee on a monthly basis, which is not true in this case. AIU claims that AmerenIP remits funds to the trustee on a daily basis, and those funds are unavailable to the company once remitted. AIU is of the opinion that Ms. Phipps' means of calculating the TFTN cost understates the true cost to AmerenIP.

AIU also notes that while Ms. Phipps claims that Mr. O'Bryan incorrectly included an additional year of cash flows in the IRR analysis, AIU opines that these cash flows must be included in the IRR analysis, as they make up the test year cost calculations. AIU notes that unlike the balance of TFTNs, which is a capital structure component and must be measured as of the end of the test year, the IRR calculates the true cost of the TFTNs and must incorporate the full test year cash flows. AIU further notes that while Ms. Phipps adjusted the amount of —~~Net~~ Proceeds Used to Retire Principal" to reflect a \$100,000 subtraction to the capital subaccount, stating that Mr. O'Bryan did not include this in his calculations. However, according to AIU, Mr. O'Bryan did include this subtraction in the last line of the —Collection Amount" column in the IRR spreadsheet, and AIU submits that this amount is embedded in his IRR calculation.

b. Staff's Position

Staff witness Phipps calculated that AmerenIP's embedded cost of TFTNs equals 4.92%. Ms. Phipps then made three adjustments, which reduced the TFTN IRR to 4.5% in comparison to AmerenIP's 5.6% IRR calculation.

Ms. Phipps adjusted the IRR analysis to begin on AmerenIP's proposed December 31, 2006 capital structure measurement date, as Staff submits that AIU's analysis incorrectly includes one additional year of cash flows because the IRR calculation begins January 1, 2006. Staff opines that calculating the cost of the TFTNs using data beginning January 1, 2006 overstates the cost of debt due to the twelve months of additional cash flows that represent the present value of the TFTN collection amounts during 2006. Staff notes that adjusting the IRR analysis by changing the measurement period to include one additional year of cash flows increases the IRR by approximately one percentage point (1.0%), and increases AmerenIP's overall cost of capital by approximately 8 basis points.

Staff submits that it is appropriate to calculate the TFTN cost as of the capital structure measurement date and that to include the 2006 cash flows in the TFTN IRR analysis would be incorrect. Staff notes that AIU chose the higher January 1, 2006 IRR (i.e., approximately 5.6%) rather than the lower December 31, 2006 IRR (i.e., approximately 4.5%) and combined it with the lower December 31, 2006 balance of TFTNs (\$172,800,000) rather than the higher January 1, 2006 balance of TFTNs (\$259,200,000). Staff submits that AIU's IRR calculation violates the present value

principle on which it rests: the value of an asset equals the cumulative value of its future discounted cash flows.

Staff further adjusted the TFTN IRR analysis by increasing the amount of —~~At~~ Proceeds Used to Retire Principal” by \$100,000 as the TFTN prospectus indicated the Trust retained \$4,220,000 of TFTN sale proceeds in the capital subaccount rather than the \$4,320,000 amount AIU’s calculation assumes. Staff avers that although Mr. O’Bryan correctly modeled that \$4,220,000 from the capital subaccount will be returned to AmerenIP in December 2008, he incorrectly modeled that \$4,320,000 of the TFTN proceeds were deposited in the Capital Subaccount in December 1998. Staff submits that failing to make this adjustment results in an artificially low amount of cash available to retire the TFTNs, thereby inflating the results of the TFTN IRR analysis.

Staff notes the TFTN coupon rate is calculated using an analysis that finds the monthly discount rate that equates the cumulative present value of the monthly cash servicing costs of the TFTNs to the principal outstanding net of over-collateralization. Staff submits that while AmerenIP calculated an annual discount rate that reflects monthly compounding, Staff calculated the monthly discount rate and multiplied it by twelve to annualize it.

Staff opines that while annualizing a periodic rate of return by compounding it to the power equal to the number of periods in a year is necessary for determining the required rate of return from the perspective of investors, the cost of TFTNs is embedded; that is, the cost of TFTNs is calculated from the perspective of the utility, not investors. Staff submits that embedded costs are annualized by multiplying the periodic rate by the number of periods in a year.

While AIU argues that annualizing the monthly discount rate used in the IRR calculation, rather than compounding it, understates the true cost to the utility because AmerenIP remits funds to the TFTN trustee on a daily basis, Staff avers that AIU’s monthly compounding in the IRR calculation overstates the embedded cost of TFTNs and should be rejected. Staff submits that the payment timing difference of TFTNs is more properly accounted for using a working capital adjustment than a cost of capital adjustment. Staff’s proposed working capital allowance for AmerenIP includes this adjustment to reflect the timing difference between AmerenIP’s TFTNs and its other long-term indebtedness, which AIU witness Adams testified was appropriate.

Staff notes that in AmerenIP’s prior electric delivery service rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)), Staff’s proposed working capital allowance included a 91.5-day lead for conventional debt and a two-day lead for TFTNs, which was accepted by the Commission. Staff submits that its proposed treatment of the AmerenIP TFTN notes is appropriate, and AIU’s suggestion that the IRR calculation requires monthly compounding should be rejected.

Staff notes that while AIU takes the position that its method of calculating the IRR to determine the cost of TFTN was approved by the Commission in the 1999 and 2001

electric DST cases as well as the 2004 gas case, Staff submits that the Orders for AmerenIP's 2001 DST case and 2004 gas case do not describe the TFTN cost calculation and can not be relied upon to support AmerenIP's IRR methodology as Staff and IP stipulated to an overall cost of capital, including a TFTN cost rate. Staff further notes that in IP's 1999 DST case, Staff and IP agreed upon the TFTN cost rate, but the Order does not describe the TFTN cost calculation.

Staff opines that the use of IRR analysis to calculate the TFTN cost was not contested in the previous case (i.e., Docket Nos. 06-0070/0071/0072 (Cons.)) and is not contested in the instant case. Staff notes that in both cases, Staff and AmerenIP calculate the TFTN cost rate using IRR analysis. In both cases, to calculate the annual IRR, Staff multiplies the monthly IRR by 12, while in contrast, AmerenIP compounds the monthly IRR. Staff further avers that in the 2006 IP DST case, the Commission concluded that Staff's method for calculating the embedded cost of TFTNs was correct.

c. Commission Conclusion

The Commission notes that this issue appears to be the same as was litigated in AIU's last DST case. The Commission has reviewed the record on this issue and again concludes that Staff's method for calculating the embedded cost of TFTNs is correct. The cost of long-term debt, including TFTNs, is known with relative certainty and should be calculated on an annual basis. Multiplying the stated monthly rate by 12 produces an annualized embedded cost that is consistent with the entire test year revenue requirement calculation. Additionally, AIU's concern about the economic impact of frequent remittance by AmerenIP to the trustee is recognized in the CWC allowance adopted in this Order. The Commission finds that Staff's method for calculating the interest rate for AmerenIP's TFTNs when combined with the appropriate CWC calculation properly reflects AmerenIP's cost of providing service. The Commission finds Staff's estimate of AmerenIP's embedded cost of TFTNs, 4.92%, to be reasonable for purposes of setting rates in this proceeding.

5. AmerenIP's Embedded Cost of Long-Term Debt

a. AIU's Position

AIU witness O'Bryan updated AmerenIP's long-term debt schedule to reflect the recent refinancing of its auction rate PCBs. AIU notes that on April 8, 2008, AmerenIP issued \$337 million of senior secured notes for the purpose of redeeming AmerenIP's outstanding PCBs that were in auction rate mode. AIU submits that the parties agree that negative credit rating actions against the bond insurers starting in December 2007 caused rates to spike in the auction rate market. AIU notes that rates on these securities, which were in the range of 1.54% - 3.93% over the period 2004-2007, saw rates climb to as high as 18%. Due to the extremely high rates on these securities recently, AIU states that Ms. Phipps measured these rates using the interest rates from the last auctions prior to the December 2007 rating actions by Moody's Investors Service ("Moody's") and S&P on the companies that insure the AIU's auction rate PCBs.

Ms. Phipps reasoned in direct testimony that one possible outcome was the refinancing of these securities due to the recent authority the Commission granted AmerenIP to do so. AIU notes that AmerenIP did refinance these securities, and as result, AIU submits that Ms. Phipps' proxy rates should be updated for actual rates that reflect AmerenIP's true amount and cost of long-term debt for the foreseeable future.

AIU submits that this updating of AmerenIP's long-term debt schedule to reflect the refinancing of its auction rate PCBs should not be considered a selective update, and notes that Ms. Phipps contemplated such a scenario in her direct testimony. AIU avers that the rates that she used were a proxy for the true rate on the PCBs and should be considered a short-term substitute until a more permanent rate can be used which would reflect the truer cost of the capital. AIU submits that that rate is now available, and given this special situation should be viewed as more appropriate than Ms. Phipps' proxy rate.

AIU's suggests that its proposed replacement of a proxy that Staff developed in light of market turmoil, with the cost of the now-known permanent replacement is appropriate and should not be considered by the Commission to be a selective update.

b. Staff Position

Staff submits that as of December 31, 2006, AmerenIP's balance of long-term debt equals \$709,096,036, and the embedded cost of long-term debt equals 7.34%.

AmerenCIPS, AmerenCILCO and AmerenIP each have outstanding variable rate long-term indebtedness in the form of PCBs with interest rates established every 7 or 35 days through an auction (the ~~—action~~ auction rate PCBs"). The parties agree that during December 2007, Moody's placed the credit ratings of the companies that insure those auction rate PCBs on review for possible downgrade and S&P assigned the ratings of those bond insurance companies to Negative CreditWatch or assigned their ratings negative Outlooks, and that those negative credit rating actions preceded a dramatic increase in the interest rates for the auction rate PCBs.

In her direct testimony, Ms. Phipps stated that during the period rates set in this proceeding are in effect, one of two events is likely to occur: 1) the market for insured tax-exempt bonds will return to a more stable equilibrium in which interest rates on such indebtedness reflect the risks of default, or 2) AIU will refinance the auction rate PCBs. Ms. Phipps testified that the results of the last auctions available at the time she filed direct testimony were not reasonable estimates of the rates AIU will incur on the associated indebtedness in either of those events. Ms. Phipps indicates she estimated the cost of the auction rate PCBs using the interest rates from the last auctions prior to the December 2007 rating actions by Moody's and S&P on the companies that insure AIU's auction rate PCBs.

Specifically, Ms. Phipps recommends using the following interest rates for AmerenIP's auction rate PCBs: 4.865% for AmerenIP's \$150 million auction rate PCBs;

4.571% for AmerenIP's \$111.77 million auction rate PCBs and 5.857% for AmerenIP's \$75 million auction rate PCBs. Staff notes that AIU accepted Staff's cost estimates for AmerenCILCO's and AmerenCIPS' auction rate PCBs, which Staff says were derived in the same manner as Staff's cost estimate for AmerenIP's auction rate PCBs, however AIU did not accept Staff's interest rate for AmerenIP's auction rate PCBs.

Staff submits that AIU proposes a selective update to AmerenIP's long-term debt schedule to reflect the April 2008 refinancing of AmerenIP's auction rate PCBs by removing \$336.77 million auction rate PCBs, including \$337 million of 6.25% Senior Secured Notes, and reflecting March 31, 2008 balances of unamortized loss for the reacquired PCBs only, which is fifteen months beyond the December 31, 2006 balances for every other long-term debt issue. Staff submits that this selective update effectively increases the embedded cost of the PCB-related indebtedness by approximately two percentage points (from 4.6% to 6.5%) and increases the embedded cost of debt for AmerenIP from 7.14% to 7.98%. Staff opines that AIU's selective update to AmerenIP's long-term debt schedule provides neither an accurate nor complete view of AmerenIP's cost of capital on either December 31, 2006, or during April 2008.

Staff recommends against allowing selective updates to AmerenIP's cost of capital. Should the Commission determine it would be appropriate to update IP's cost of capital to reflect the 6.25% interest rate Senior Secured Notes AmerenIP issued to redeem its auction rate PCBs, Staff recommends the Commission also update the costs of variable rate debt issues (short and long-term) and the cost of common equity, leaving the capital structure balances unchanged. Further, since AmerenCILCO and AmerenCIPS also refinanced PCBs during April 2008, Staff submits that their variable rate debt and common equity costs should be updated as well.

Ms. Phipps testified that the updated cost of short-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 3.95%, 3.92% and 3.74%, respectively, and the updated cost of long-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 6.63%, 6.24% and 7.94%, respectively. Staff submits that for AmerenCILCO and AmerenCIPS, the updated interest rate for auction rate PCBs equal their respective updated short-term debt cost, while for AmerenIP, the updated interest rate for auction rate PCBs equals 6.25%, which is the interest rate for the Senior Secured Notes that AmerenIP issued in April 2008 to replace auction rate PCBs.

Should the Commission determine it is necessary to update the AIU's cost of capital estimates due to recent financing activity in connection with redeeming and refinancing auction rate PCBs, then Staff submits that the cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's gas delivery services operations would be 7.94%, 8.14%, and 8.90%, respectively. Those cost of capital recommendations reflect Staff witness Freetly's updated 10.73% cost of equity estimate for the utilities' gas delivery services operations. Staff asserts that the updated cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's electric delivery services operations would be 7.75%, 7.94%, and 8.69%, respectively. Those cost of capital

recommendations reflect Ms. Freetly's updated 10.32% cost of equity estimate for the utilities' electric delivery services.

Staff states that in AIU's 2006 electric delivery services rate case, the Commission noted the risks inherent in selective updates to capital structure components, rejected AIU's proposed selective updates to interest rates, and endorsed measuring all the costs of capital at or over the same period. Staff opines that AIU's attempted change in the auction rate PCB's also changes costs and balances included in AmerenIP's embedded cost of long-term debt and ignores AmerenIP's other recent financing activity and changes to other capital structure costs and balances that occurred between December 31, 2006 and April 2008. Staff avers that until the conclusion of AmerenIP's next rate case, Staff's proposed cost of debt will be more than sufficient to cover the additional interest expense AmerenIP incurs on its new bonds relative to the interest expense of its auction rate PCBs.

Staff recommends its calculation of AmerenIP's embedded cost of long-term debt be adopted and AIU's selective update should be rejected. Should however, the Commission adopt AIU's calculation of the embedded cost of long-term debt, Staff submits that the Commission should adopt Staff's alternative cost of capital recommendations for AmerenCILCO, AmerenCIPS and AmerenIP. Despite the flaws inherent in Staff's alternative recommendations for AIU, Staff insists they are superior estimates of the cost of capital in comparison to AIU's selective update to AmerenIP's long-term debt schedule because they provide a more complete and more accurate view of AIU's cost of capital.

c. Commission Conclusion

The Commission notes that it has generally endorsed the principal of measuring all of the costs of capital at or over the same period. The Commission is of the opinion that such an approach generally contributes to a test year revenue requirement that matches the cost of providing services and, in the Commission's view, is fair to both consumers and the utility investors. As the Commission noted in AIU's last delivery services case:

The Commission becomes wary when a party proposes updates to certain components of the cost of capital without providing updates to all components. Allowing selective updates could serve to encourage utilities to only provide updates if the cost of components increased. Absent sufficient justification, this would be unfair to ratepayers... (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 109)

The parties are in agreement that an outside event affected the credit markets, and resulted in interest rates on auction rate PCBs that were far higher than the interest rates typically associated with those PCBs. It appears to the Commission that both parties have presented an adjustment to the actual interest rate incurred in the December, 2007 auction of AmerenIP PCBs, one prospective and one retrospective,

and the question presented is whose update is more appropriate. The Commission is concerned that AIU's proposed use of the actual results from the April 8, 2008 refinancing does not take into consideration other relevant changes to AIU's cost of capital components and might be considered a selective update. The fact that Staff, in the event the Commission adopts an update to AmerenIP's PCB cost, recommends multiple other changes to components of cost of capital, verifies that the selective update concern is warranted.

Given that the cost of capital changes constantly, the Commission is reluctant to start down a path of selective updates or continuous updates during the pendency of a rate case. The Commission further notes that AIU has accepted Staff's proposed method for calculating the interest rates associated with AmerenCIPS' and AmerenCILCO's PCBs. Staff indicates it made those calculations in a similar manner to Staff's proposal for AmerenIP and that AmerenCIPS and AmerenCILCO also refinanced the auction rate PCBs in April 2008. The Commission is concerned that AIU fails to explain why the AmerenIP PCBs should be treated differently than the AmerenCIPS and AmerenCILCO PCBs.

Thus, the Commission finds that AIU's proposal to update the cost of AmerenIP's PCBs should be rejected. For purposes of this proceeding, the Commission finds Staff's original estimate of AmerenIP's embedded cost of debt, 7.34%, and its proposed balance of long-term debt, \$709,096,036, to be reasonable for purposes of setting rates in this proceeding.

6. AmerenCIPS' Embedded Cost of Long-Term Debt

The parties are in disagreement over Staff's recommended cost of AmerenCIPS' long-term debt, wherein Staff removed the incremental cost of AmerenCIPS' June 14, 2006 bonds. The parties are in agreement that in May 2005, AmerenUE transferred its Illinois utility assets to AmerenCIPS in exchange for a \$67 million, five-year promissory note bearing a 4.7% interest rate. They also agree that on June 14, 2006, AmerenCIPS issued \$61.5 million, 30-year bonds with a 6.7% interest rate, using the proceeds from that debt issuance to pre-pay the intercompany note held by AmerenUE. AIU had calculated a long-term debt cost for AmerenCIPS of 6.67%, whereas Staff calculates a long-term debt cost of 6.27% after removing the incremental cost of the June 14, 2006 refinancing.

The Commission notes that all parties agree with the general financial principle that as interest rates rise, the market value of outstanding fixed-interest rate debt falls such that the yield on that debt is competitive with that on new debt that pays interest at the new, higher interest rates. Both parties further agree that this is true due to the fact that the future stream of cash flows, both interest and principal, is less valuable when interest rates rise because the interest rate on the note is fixed.

a. AIU's Position

AIU submits that Ms. Phipps improperly removed from AmerenCIPS' embedded cost of long-term debt the incremental cost due to its decision to refinance the 4.70% intercompany note with 6.7% bonds. AIU takes the position that AmerenCIPS was justified in refinancing the 4.70% note, noting that the refinancing extended the date of final maturity from 2010 to 2036, while the original 4.70% note had a remaining life of just over three years. AIU submits that this extension reduced AmerenCIPS' refinancing risk and that the more permanent capital achieved by extending the term corresponded with the permanent T&D assets which it financed. In addition, AIU avers that the new structure relieved AmerenCIPS from having to fund annual amortization payments, and that the principal payments that remained at the time the note was refinanced were \$5.6 million in May 2007, \$5.9 million in May 2008, and \$6.2 million in May 2009, which would have been made in addition to quarterly interest payments. AIU notes that the 6.70% bond has a non-amortizing bullet structure with full principal paid at maturity, pays interest semi-annually, and affords AmerenCIPS valuable flexibility through the extension of maturity and freedom from the burden of annual amortization payments.

While AIU agrees that an inverse relationship exists between interest rates and bonds prices, and that the value of a note or loan to the lender falls whenever interest rates rise, AIU submits that this principle is not relevant to a lender or an initial investor at loan origination. Further, early redemption terms are set at the note's inception and are typically not negotiated during the life of the loan, with the possible exception being a distress/bankruptcy situation.

AIU notes that the AmerenCIPS intercompany note states in part:

. . . AmerenCIPS (the "~~Maker~~"), promises to pay to the order of Union Electric Company d/b/a AmerenUE (the "~~Payee~~")....the principal amount of \$66,695,406...Upon receiving the prior written consent of the Payee, the Maker shall have the right to prepay the principal amount of this Note, in whole or in part, without premium or penalty. All partial prepayments shall be applied first to accrued interest under this Note and then to principal installments (AIU Initial Brief at 251)

AIU submits that the above excerpt states clearly the principal amount to be paid, and that any prepayment is without premium or penalty. AIU claims that there is no mention of a discount nor anything that can be construed as an ongoing negotiation between the parties regarding the amount ultimately owed.

AIU avers that Staff fails to distinguish the difference between the primary loan/bond market and the secondary market. AIU agrees that in an environment of increasing interest rates, the value of the AmerenCIPS note would decline, and were AmerenUE (the lender or investor) to attempt to sell the note to a third party in the secondary market, it would likely have had to accept a price below par to do so. AIU

submits that AmerenCIPS, as obligor, was bound by the contractual terms of the note that requires the payment of the full principal amount of the loan at or before maturity.

AIU notes that Staff argues that AmerenCIPS extended a benefit to AmerenUE by retiring a promissory note before its due date and that reflecting the full cost of the replacement note would violate Section 9-230 of the Act by increasing AmerenCIPS' cost of capital due to its affiliation with AmerenUE. Staff takes the position that when AmerenCIPS paid AmerenUE the entire balance to retire the note, it gave AmerenUE an unnecessary benefit and the resulting refinancing is unreasonable.

AIU submits however, that AmerenUE is not in the regular business of lending or financing third parties, but is instead a public utility in Missouri and was the lender here only because AmerenCIPS signed a promissory note when it acquired AmerenUE's Metro East properties. AIU contends that, unlike an institutional lender, AmerenUE would not be expected to take the money from the early retirement of the note and return to the debt markets to lend the money to another party at higher interest rates. AIU submits that there was no evidence that AmerenUE was dissatisfied with the interest rate under the note or that AmerenUE would have been willing to accept a discount to the principal for early payment. AIU posits that unlike the case of an institutional lender, there is no obvious opportunity cost to AmerenUE from remaining a party to the note. AIU submits that Staff's theory is inapplicable here, there is no violation of Section 9-230, and Staff's adjustment should be rejected.

b. Staff's Position

Staff witness Phipps calculated a 6.27% embedded cost of long-term debt for AmerenCIPS, while AIU proposed a 6.67% embedded cost of long-term debt for AmerenCIPS. Staff submits that the difference in those calculations results from Staff's adjustment to remove from AmerenCIPS' embedded cost of long-term debt the incremental cost due to AmerenCIPS' decision to refinance a 4.70% intercompany note with 6.7% senior secured notes. Staff avers that this adjustment is required by Section 9-230 of the Act, which prohibits including in a utility's allowed rate of return any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies.

To assess whether interest rates had changed from the date the note was issued until one year later when AIU issued long-term bonds to replace the intercompany note, Ms. Phipps examined the 4.7% interest rates on the note in comparison to the implied interest rate for bonds with similar risk and terms to maturity. Ms. Phipps testified that on May 5, 2006, concurrent interest rates for 3-year and 5-year BBB+/Baa1 bonds indicate the implied yield on 4-year BBB+/Baa1 bonds equaled approximately 5.7% versus 4.7% on May 2, 2005, the date when AmerenCIPS issued the intercompany note. Staff further notes that although interest rates on 4-year bonds had risen since May 2005, AmerenCIPS did not receive any discount on the repurchase price of the promissory note. Staff asserts that due to this increase in interest rates, AmerenCIPS should have received a discount on the repurchase of the promissory note.

Relying on Section 9-230 of the Act, Staff removed from AmerenCIPS' embedded cost of long-term debt any incremental cost increase due to its decision to refinance the 4.7% intercompany note with 6.7% bonds because the loan agreement between AmerenCIPS and AmerenUE did not oblige AmerenCIPS to retire the promissory note at face value on the demand of AmerenUE, and in a transaction with an unaffiliated counterparty without such a provision, the borrowing entity would be able to redeem its indebtedness at a discount to face value.

Staff argues that because the value of a loan to the investor (i.e., lender) falls below face value whenever interest rates rise on loans with similar terms and risks. Staff says that in an arms length transaction, a borrower would not have to pay full principal amount to prepay a loan carrying a below market interest rate unless the original loan agreement required the borrower to do so. Staff submits that —make whole” provisions are designed to protect lenders' gains in market value in the event the borrower wants to refinance its debt should interest rates fall by requiring borrowers who want to refinance debt that bears above-market interest rates to pay in excess of the principal amount, not to protect their losses in market value whenever interest rates rise. Staff posits that the intercompany note did not include such a provision, and therefore, AmerenUE's principal amount was not protected from such a loss and it should not be granted after-the-fact.

Staff argues that AmerenCIPS' alleged inability to pay less than principal amount for below market rate debt is inconsistent with AmerenIP's experience. Staff notes that during January 2000, when long-term Baa-rated utility bond yields had risen to 8.40%, AmerenIP redeemed \$32 million of its 7.50% first mortgage bonds maturing in 2025. Staff notes that AmerenIP's long-term debt schedule shows a gain was realized on that redemption due to higher long-term interest rates on the redemption date vis-à-vis the interest rate on the bonds.

To remove any incremental cost increase due to the refinancing, Ms. Phipps proposes two adjustments. First, she proposes dividing the balance of the 6.7% debt issuance in two components, with a 4.7% interest rate applied to the first component, which was the portion of the intercompany note that would have been outstanding as of June 30, 2007 had AmerenCIPS not retired it before maturity (i.e., \$55,688,092). She then applies a 6.7% interest rate to the second component, which was the balance of the \$61.5 million bonds (i.e., \$5,811,908, which equals \$61,500,000 less \$55,688,092). She then proposes reducing the unamortized balances of debt discount and expense for the 6.7% bonds in proportion to the principal amount of those bonds that she included in AmerenCIPS' embedded cost of long-term debt. Next, she calculated the annual amortization expense for debt discount and expense relative to the prorated unamortized balance using straight-line amortization.

Staff notes that AIU opposes Staff's adjustment to remove the incremental increase in AmerenCIPS' cost of capital due to its intercompany note with AmerenUE and argues the refinancing benefited AmerenCIPS by extending the maturity from 2010

to 2036 and eliminating the obligation to fund \$6 million annual amortization payments. Staff submits that AIU exaggerates the amount of flexibility gained by refinancing the intercompany note with bonds. Staff notes that not only did the original note include a provision that would allow AmerenCIPS and AmerenUE to extend the maturity of the note another five years by mutual agreement, but further, the note was subordinated to all other of AmerenCIPS' indebtedness. Staff avers that any benefits AmerenCIPS attributes to refinancing the note would have been benefits at the time of the asset transfer which originated the note. Staff submits that neither of AIU's arguments relating to the perceived benefits associated with refinancing the intercompany note are compelling.

Staff further suggests that neither of the arguments relating to the perceived benefits associated with refinancing the note are relevant. Staff insists that Section 9-230 of the Act does not allow the Commission to consider what portion of a utility's increased cost of capital caused by an affiliation is reasonable and therefore should be borne by ratepayers. According to Staff, the Second District Appellate Court in Illinois Bell Telephone Co. v. Illinois Commerce Comm'n, 283 Ill. App. 3d 188, 207, 218 Ill. Dec. 598, 669 N.E.2d. 919 (1996), held that —if a utility's exposure to risk is one iota greater, or if it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its [rate of return] calculation.”

Staff submits that consistent with Section 9-230 of the Act, it would be illegal to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. Staff notes that AIU does not dispute that the refinancing increased AmerenCIPS' cost of capital, and Section 9-230 of the Act prohibits including in AmerenCIPS' cost of capital any increase that is the direct or indirect result of AmerenCIPS' affiliation with unregulated or non-utility companies.

While AIU suggests that the benefits justified refinancing AmerenCIPS' intercompany note from AmerenUE, Staff avers that it has never argued that AmerenCIPS should not have refinanced the note and Staff takes no position on that decision. Rather, Staff takes the position that AmerenCIPS paid an above-market cost to refinance the note.

While AIU claims that in the market, AmerenCIPS would never be able to prepay a note for less than the principal amount, Staff submits that this note did not contain language requiring redemption of the note for no less than the principal amount upon demand by AmerenUE. Staff avers that the note at issue in the instant proceeding makes redemption optional, and that under those circumstances, the borrower, in this case AmerenCIPS, should not redeem a note that carries a below-market interest rate by repaying 100% principal unless the note required the borrower do so.

While AIU argues that because the note was privately held, AmerenCIPS could not redeem it at a market rate below face value, Staff notes that AmerenCIPS chose to enter into a private loan agreement with an affiliate. Staff submits that had AmerenCIPS gone to the market to raise funds, rather than borrow from an affiliate, AmerenCIPS would have had the opportunity to repurchase outstanding, below-market rate indebtedness for less than face value. Staff posits that for ratemaking purposes, the Commission must treat the intercompany note as if it had been held by an unaffiliated party, and under this circumstance, AmerenCIPS would have had the opportunity to repurchase that indebtedness at market rates rather than face value.

Staff submits that its calculation of AmerenCIPS' embedded cost of long-term debt, which is consistent with the requirements of Section 9-230 of the Act, should be adopted and AIU's cost calculation should be rejected.

c. Commission Conclusion

The Commission notes that Staff is rightly concerned about the possibility of cross-affiliate subsidization and the possibility that AmerenCIPS' ratepayers are providing a windfall to AmerenUE by the redemption at issue here. The parties are in agreement that interest rates had risen since the note in question was issued. Staff argues that if AmerenCIPS made the business decision to refinance this note, it should have been able to redeem them for less than face value due to the interest rate environment. AmerenCIPS submits that this situation does not apply to bonds or notes unless they are in the secondary market, and suggests that ratepayers are benefitting by the restructuring of this debt as AmerenCIPS makes interest-only payments, and the term of this debt is now extended.

The Commission finds that while there may be some collateral benefits to AmerenCIPS' ratepayers, it appears that there is an increased cost due to this transaction, and pursuant to 9-230 of the Act, it would be improper to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. The Commission finds that for purposes of this proceeding, Staff's calculation of AmerenCIPS' embedded cost of long-term debt, 6.27%, and its balance of long-term debt, \$446,741,385, are reasonable and they are hereby approved.

D. Cost of Preferred Stock

Staff and AIU agree that the embedded cost of preferred stock for AmerenCILCO, AmerenCIPS and AmerenIP equals 5.34%, 5.13% and 5.01%, respectively. The Commission finds these embedded costs of preferred stock to be appropriate, and they will be adopted for the purposes of this Order.

E. Cost of Common Equity

1. Overview

a. Staff's Position

Staff witness Freetly estimates the investor-required rate of return on common equity to be 10.72% for the natural gas distribution operations and 10.68% for the electric delivery service operations of AIU. Ms. Freetly measured the investor-required rate of return on common equity with the discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. For the AIU gas utilities, she applied those models to a sample of gas distribution companies. For the AIU electric utilities, she applied those models to a sample of regulated electric utilities that are assigned industry classification codes of 4911 (electric services) or 4931 (electric and other services combined) within S&P's Utility Compustat. Specifically, she applied them to those utilities that have neither pending nor recently completed significant mergers, acquisitions or divestitures; that have a long-term growth rate from Zacks Investment Research ("Zacks"); and whose beta was not affected by significant events. Ms. Freetly did not include Ameren Corporation in her Electric sample due to the proximity of an 18% decline in Ameren's stock price to a conference call during which Ameren management discussed the pending Illinois rate cases.

Staff notes that in order to determine the suitability of her cost of equity estimates for AIU's gas and electric utility operations, Ms. Freetly assessed the risk level of her gas and electric samples relative to that of each of the Illinois utilities. She calculated the funds from operations ("FFO") to interest coverage ratios and FFO to total debt ratios for the gas and electric samples and for the natural gas distribution and electric delivery service operations of each of the Illinois utilities. Staff submits that to estimate the risk of AIU going forward, Ms. Freetly compared the financial strength implicit in the revenue requirement Staff recommends for each of AIU's gas and electric operations to Moody's guidelines for electric utilities with medium business risk. Staff notes that although no formula exists for determining an assigned credit rating, Moody's provides broad guidelines for the ratio ranges that may be seen generally at different rating levels for regulated electric utilities. The FFO to interest coverage ratio equals interest divided into the sum of FFO and interest. The FFO to debt coverage ratio equals FFO divided by total debt. Each component was based on its contribution to Staff's recommended revenue requirement for AmerenCILCO, AmerenCIPS and AmerenIP.

Staff avers that for AIU's gas utility operations, the financial ratios implied by the capital component costs and capital structure are consistent with those of the gas sample, and therefore Ms. Freetly did not adjust the cost of common equity of the gas sample. Staff submits that the electric sample's FFO to interest coverage ratio of 4.0X and the FFO to total debt ratio of 18% fall within the guideline range for a Baa credit rating. Staff's revenue requirement recommendations, including the capital component costs, are indicative of a level of financial strength that is commensurate with an Aa3/A1 rating for Ameren CIPS and A1 ratings for AmerenCILCO and AmerenIP. Staff posits

that this comparison of financial ratios indicates that the electric sample has lower financial strength and therefore higher risk than AIU's electric delivery service operations. Staff notes that financial theory posits that investors require higher returns to accept greater exposure to risk, and that the investor-required rate of return is lower for investments with less exposure to risk. Staff submits that given the difference between the forward-looking financial ratios of AIU's electric delivery service operations and the financial ratios of the electric sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of AIU's costs of common equity for electric delivery service operations. Based on her analysis, Ms. Freetly adjusted the electric sample cost of equity downward 30 basis points, and submits that this 30 basis point adjustment for the electric operations of AmerenCILCO, AmerenCIPS and AmerenIP equals the spread between Baa1 and A1 rated 30-year utility debt yields as of February 13, 2008.

Staff submits that should the Commission accepts AIU's position to update the cost of long-term debt to reflect the recent refinancing of AmerenIP's auction rate bonds, Staff suggests that its updated cost of equity analysis should also be incorporated into the overall cost of capital calculation to obtain concurrent estimates of the costs of AIU's sources of capital. Staff's updated analysis, should the Commission accept AmerenIP's position on the auction rate bonds, indicates that the cost of equity is 10.73% for the natural gas distribution operations of AIU and 10.32% for the electric delivery service operations of AIU.

Staff notes that IIEC continues to recommend a return on common equity of 10.0% for both the electric and gas utility operations of AIU, while CUB recommends a return on equity of 8.955% for AIU gas distribution operations and 9.046% for the electric distribution operations.

b. AIU 's Position

AIU indicates in its Initial Brief that it has decided to accept, for the limited purposes of this proceeding, Staff's recommended cost of common equity. Accordingly, AIU has updated its recommended weighted cost of capital to reflect the acceptance of Staff's determination of the cost of common equity.

c. CUB's Position

CUB submits that it has introduced substantial financial literature which indicates that adhering to past Commission practices will result in an over-inflated return on equity. CUB avers that in order to achieve just and reasonable rates, the Commission should render a decision consistent with this new knowledge and the law and order a return on equity of 8.955% for AIU's gas distribution operations and 9.046% for its electric distribution operations.

CUB notes that a utility's required return on equity, or cost of equity, is the level of profit necessary to attract investment to a business with the utility's level of risk, and if

the cost of equity is reasonable and prudently incurred, it is a cost of doing business that utilities have a constitutionally protected opportunity to recover. CUB avers that the Act directs the Commission to ensure that the cost of equity used to develop rates fairly compensates investors for their risk, and assure that customers do not pay an excessive or unreasonable return in the utility's rates. CUB submits that these opposing responsibilities can be balanced fairly only when the Commission thoroughly considers the objective market factors that determine a fair return on investment. CUB avers that investors' required returns for investment in an enterprise of a given level of risk will change as the objective factors that define the equity markets change over time.

CUB notes that as this necessary cost of equity is not directly observable in the market for a particular utility, financial analysts have developed tools, such as the DCF model and CAPM, to estimate the cost of equity from observable market factors.

CUB notes that AIU initially recommended a return on equity of 11.00% for both its gas and electric operations, based on a DCF, CAPM, other risk premium analyses, and a comparable earnings test, but that AIU has now agreed to accept Staff's return on equity recommendations. CUB notes that Staff recommends a return on equity for AIU's electric distribution operations of 10.68%, and a 10.72% return on equity for AIU's gas distribution operations. CUB submits that Staff's recommendation is based on an average of widely divergent results from its DCF and CAPM analysis. CUB avers that Staff's approach is flawed as it ignores recent research on calculating cost of equity. CUB bases its recommendation on the results of a DCF model that incorporate the findings from the most current and advanced studies of financial markets. Based on the results of this model, CUB recommends an 8.955% return on equity for AIU's gas distribution operations and 9.046% return on equity for AIU's electric distribution operations. CUB submits that these represent the returns necessary to maintain AIU's access to equity capital markets on reasonable terms.

CUB submits that Mr. Thomas' calculation of rate of return on equity is based on significant financial research, is consistent with the law, and does not result in excessive rates to consumers. Therefore, CUB believes its recommended rate of equity, which is supported by substantial evidence presented in this docket, should be adopted.

d. IIEC's Position

IIEC witness Gorman recommends that the Commission award AIU a return on common equity of 10.0% for both the electric and gas utility operations of each of the AIU utilities. His recommendation is based on the results of his multi-stage DCF model, Risk Premium ("RP") model, and CAPM analyses. In part because the common equity shares of AIU are not publicly traded, Mr. Gorman's analyses applied the models to observable market information for groups of publicly traded utility companies that approximate AIU's investment risk. Mr. Gorman notes that proxy groups were also used by the other cost of equity witnesses in the case.

Mr. Gorman developed one proxy group himself to proxy AIU's investment risk for both gas and electric operations, while the other was the same proxy group used by AIU witness McShane in her cost of equity analyses. Mr. Gorman deemed both groups to have comparable investment risk to AIU, and that within that range of comparable risk, the Gorman proxy group was slightly more risky than AIU, while the McShane proxy group was slightly less risky. IIEC asserts that Mr. Gorman's analyses develop cost of equity estimates using higher and lower risk proxy groups that bracket the risk of AIU, and submits that the similarity of his results for the two groups reinforces the appropriateness of his estimates.

IIEC notes that as current economic circumstances can affect the suitability of particular cost of equity modeling techniques for developing cost of equity estimates, Mr. Gorman first investigated the market's current perception of the changing electric utility industry. Mr. Gorman testified that the market sees the industry in a capital spending cycle that is producing very strong growth in rate base, and in related earnings and dividends, which is providing a vehicle for strong growth over at least the next three to five years. IIEC submits that this transitional spending cycle has important implications for estimating a proper cost of common equity and explains Mr. Gorman's use of a multi-stage DCF model.

Mr. Gorman's analyses showed that a two-stage DCF model suggested a return on equity of 9.6%; Risk Premium Analysis, 10.0%, CAPM, 10.4%; and the midpoint-range of his analysis and his recommendation is 10.0%. IIEC submits that this proposed return on equity provides AIU with an opportunity to achieve cash flow credit metrics that will support an investment grade bond rating, allow AIU to maintain its financial integrity, and represents fair compensation for AIU's investment risk and will support AIU's access to credit markets on reasonable terms.

While IIEC recognizes that AIU has accepted Staff's recommended return on equity, IIEC notes that AIU continues to argue against Mr. Gorman's analysis. IIEC submits that its analysis is correct and that Mr. Gorman's recommended return is appropriate.

2. Annual Versus Quarterly DCF Model

a. Staff's Position

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments to the holders of that stock. Staff avers that as a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. Staff notes that as the companies in Ms. Freetly's gas and electric samples pay dividends quarterly, she applied a multi-stage, non-constant-growth quarterly DCF model.

Staff notes that Ms Freetly modeled three stages of dividend growth. The first, near-term growth stage is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year, while the third or —steady-state” growth rate is assumed to begin after the tenth year and continue into perpetuity.

Staff submits that for the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of February 14, 2008. To estimate the long-term growth expectations for the third, steady-state stage, she utilized the implied 20-year forward U.S. Treasury rate in ten years, 5.15%. The growth rate Ms. Freetly employed in the intervening, five-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. Staff avers that the growth rate estimates were combined with the closing stock prices and dividend data as of February 14, 2008, and based on these growth assumptions, stock price, and dividend data, Ms. Freetly’s DCF estimate of the cost of common equity was 9.41% for the gas sample and 10.01% for the electric sample.

While CUB claims that the Commission should use an annual DCF model because the quarterly adjustments to expected dividend yields result in doubly counting the effect of quarterly growth and thus, overcompensate shareholders at the expense of ratepayers, Staff submits that CUB witness Thomas has raised a working capital issue, not a cost of common equity issue. Staff submits that a working capital allowance compensates a utility for any delay between the time it expends cash to provide service and the time it receives cash from its customers for that service, and if a utility has authorized an appropriate working capital allowance, it will receive cash to pay for all costs of service as they come due. Staff avers that if an appropriate working capital allowance is authorized, CUB’s argument is invalid because the working capital allowance will eliminate any surplus or deficit in earnings created by the timing of the utility’s cash collections and disbursements. Staff submits that because utility companies pay cash flows (i.e., dividends) over the course of a year and not all at the end of the year, use of a quarterly DCF model is not only appropriate for rate setting purposes, it is necessary for a utility to recover its true cost of common equity. Staff also notes that the Commission has explicitly rejected the use of an annual DCF model in previous proceedings. Staff argues that CUB’s models variously ignore the time value of money, ignore the investor required return, and understate the cost of equity.

Staff submits that the argument regarding the use of a quarterly DCF versus an annual DCF model is a basic question of the time value of money, and note that CUB acknowledges the greater value of quarterly dividends relative to a single, annual dividend of the same total amount paid at the end of the year.

b. CUB’s Position

CUB notes that DCF estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future, and DCF uses current

stock price and expected cash flows from dividends and earnings growth to estimate the return that investors expect to receive. CUB submits that investors' expectations of growth and cash flows are driven largely by historical experience, and that analysts are frequently overly optimistic.

In calculating the return on equity using DCF, CUB witness Thomas began with the same samples of comparable utilities used by AIU. Mr. Thomas removed eleven companies from the electric sample and one company from the gas sample as, in his opinion, their levels of historic growth were not sustainable. Mr. Thomas posits that inclusion of these companies introduces inappropriate bias into the sample.

CUB submits that it has introduced evidence that showed that the quarterly adjustments to expected dividend yield result in double counting the effect of quarterly growth and thus overcompensates shareholders at the expense of ratepayers. CUB avers that the use of any method that double-counts the effect of quarterly growth, and overcompensates investors at the expense of rate payers is inconsistent with the law and must be rejected.

CUB argues that this double-counting problem arises because investors, who receive their dividends quarterly, are able to reinvest their dividends and realize returns on those reinvestments. CUB submits that should the Commission authorize an adjustment to DCF to account for quarterly growth and compounding, the Commission increases the returns that it grants investors, while those investors are already earning more because of the timing of their dividend payments.

CUB posits that Staff and AIU inappropriately rely on outdated studies and findings from financial literature. CUB opines that Mr. Thomas relies on more recent and uncontroverted financial literature, which reveals the cost of equity should actually be much lower than Staff's estimates. CUB submits that recent studies have shown that CAPM contains a substantial bias, and is unreasonable to rely on to estimate a utility's cost of equity.

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3. Growth Rates

a. AIU's Position

AIU notes that IIEC witness Gorman's uses a two-stage DCF model that relies on two separate measures of investor growth expectations; the consensus of analysts' forecasts of earning growth for five years, followed by the consensus forecast by economists of long-term nominal growth in the economy as a proxy for the growth rate that utility investors expect into perpetuity. AIU submits that Mr. Gorman's two-stage DCF model represents a departure from his past practice, and notes that in prior proceedings before this Commission and other regulatory commissions prior to 2008, Mr. Gorman had relied solely on a single-stage constant growth DCF model. AIU posits that in this proceeding, Mr. Gorman has abandoned the constant growth model, on the grounds that the results are too high, because the analysts' forecasts of growth are too high to be sustainable.

AIU notes that this does not mean that Mr. Gorman is wrong for using a two-stage DCF model as one of his tests to estimate the cost of equity, as AIU witness McShane also used a two-stage DCF model as one of her five tests to estimate a fair return on equity for the AIU. AIU submits however, it is not reasonable to discard the results of the constant growth test, which is based on the more objective measure of investors' growth expectations than the two-stage model. AIU posits that a reasonable

approach would be to give equal weight to the results of the constant growth and two-stage models. AIU submits that the result of Mr. Gorman's constant growth DCF model, applied to his sample of electric utilities, is 11.66%, and giving equal weight to both the constant growth and two-stage model changes Mr. Gorman's DCF result to 10.6% (average of 9.6% and 11.7%).

AIU avers that Mr. Thomas recommends historic internal growth in the application of the DCF test, which AIU submits is not reasonable. AIU posits that the use of historical internal growth rates measured over a specific period, is a purely subjective choice on Mr. Thomas' part, with no objective link to investor expectations for the future that are embedded in current stock prices. AIU submits that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. AIU notes that the average achieved returns on equity over the 2002-2006 period that Mr. Thomas relied on were 12% for his gas sample and 11% for his electric sample, and according to the Value Line forecasts that Mr. Thomas provided, the samples are forecast to earn 11.9% and 11.7%, for gas and electric respectively, during 2010-2012.

While Mr. Thomas suggests investors are expecting utilities to earn only a 9.0% return on equity, AIU submits that Mr. Thomas fails to acknowledge that dividend payout ratios have declined for both his samples during the 2002-2006 period, and are expected to decline further. AIU notes the dividend payout ratio for Mr. Thomas' electric sample was 70% in 2002, but had declined to 61% by 2006, and are forecast to decline further to 57% in 2010-2012. AIU notes that failure to properly take this decline into account will result in an understatement in the $-bx\ r$ internal growth rate. In Mr. Thomas' electric utility sample, the average retention rate over the period 2002-2006 was 35%, while the forecast 2010-2012 retention rate is 43%. AIU argues that failure to recognize the higher retention rate would understate expected growth. AIU submits that by focusing on internal growth only, Mr. Thomas fails to consider any sustainable growth from external financing (the "SV" component of sustainable growth), and notes that failure to include the SV component can seriously understate the expected sustainable growth rate. This is particularly true during periods when utilities need to raise substantial amounts of capital to invest in infrastructure. AIU recommends the Commission reject Mr. Thomas' DCF method, and thus his recommended return on equity.

b. Staff's Position

Staff opines that CUB witness Thomas' position on the issue of growth rates is not clearly thought out. Staff notes that on one hand he argues that analyst growth rate forecasts should not be used exclusively, yet he ignores analyst growth rate forecasts when performing his DCF analysis and relies solely on a $-bx\ r$ growth rate estimate derived from historical data. Staff notes that this approach produces a growth rate of 4.21% for his electric sample, which is 39% lower than the lowest of his four analyst EPS growth rates (6.91%) and 52.5% lower than the highest of his four analyst EPS growth rates (8.86%) noted in his testimony. Staff submits that Mr. Thomas' $-bx\ r$ approach produces a growth rate of 4.69% for his gas sample. Staff suggests that if Mr.

Thomas had given weight to any of the analyst growth rates in his DCF analysis, the resulting costs of equity would have been higher than his recommendations of 8.955% for gas and 9.046% for electric.

While Mr. Thomas cites several studies in support of his conclusion and implies that those studies can be applied to utility growth rates, Staff avers that those studies do not support his position. Staff suggests that the studies he cites report generalized findings for all common stocks, and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth. Staff notes in contrast, a study that indicates analyst growth rate estimates for utilities are not overstated.

Staff avers that the financial literature that Mr. Thomas cites study whether or not analysts' growth estimates are too high relative to achieved growth, as measured after the fact, and as such, they are ex post assessments of analyst growth rates' ability to accurately predict future growth, not assessments of analyst growth rates' value as estimates of investors' ex ante expectations. Staff notes that as investors' growth expectations are forecasts of the future, they may differ significantly from the ex post achieved growth. Staff submits that a cost of equity witness attempts to estimate investors' true growth expectations, irrespective of their accuracy as predictors of future growth. Staff posits that as long as analyst growth rates reflect investors' true growth expectations, use of analyst growth rates will accurately estimate the cost of equity, if properly applied in a correctly specified DCF model. Staff submits that Mr. Thomas incorrectly implies that analyst growth rates should be judged on their ability to accurately predict future growth, rather than on their value as proxies for investors' ex ante expectations.

Staff notes that Mr. Thomas argues that in circumstances where the dividend payout ratio is expected to change, use of the growth formula " $b \times r$ " to estimate expected future growth is superior to analysts' forecast. Staff notes that while Mr. Thomas indicates that Value Line's EPS and dividends per share ($-DPS$) growth expectations differ and neither correctly measures investor expectations, Staff notes that his solution rejects both and substitutes a growth rate that is almost a full percentage point less than either the EPS or DPS growth projection.

Staff submits that Mr. Thomas inappropriately extrapolates from a single source to suggest that investors, generally, are expecting dividend payout ratios to change. Staff notes that the difference between the Value Line dividend growth rates and earnings growth rates is not very large, and Staff submits that this does not indicate changes in dividend payout ratios beyond normal year-to-year fluctuations. Staff opines it is unrealistic to expect dividend payout ratios to remain absolutely constant in the near term. Staff further opines that Value Line's growth normalization technique for calculating forecasted growth rates is too mechanistic to ensure proper normalization. Staff submits that Value Line takes a simple three-year average of the base line data, such as EPS and DPS, to approximate the results of normal operations, however, if that three-year base is abnormally high, the growth rate indicated by the forecasted EPS or DPS will be lower than appropriate. Conversely, if that three-year base is abnormally

low, the growth rate indicated by forecasted EPS or DPS will be greater than appropriate.

Staff opines that even if one were to agree that the divergence of DPS and EPS growth disqualifies either for use in a DCF analysis, CUB's solution is inappropriate. Staff submits that when DPS grows more slowly than EPS, sustainable growth must be higher than DPS growth, not lower. Therefore, even if one assumes that the difference in the Value Line growth projections for DPS and EPS is sufficient for rejecting them both, which Staff disputes, the long-term steady state growth rate is higher than the DPS growth rate rather than lower as Mr. Thomas has estimated.

Staff notes that Mr. Thomas used historical dividend payout ratios and returns on equity to derive his $b \times r$ growth estimate, which he then added to the current dividend yield of each company in his samples to derive his cost of equity estimates. Staff avers it is inconsistent to apply a growth rate that reflects historical dividend payout ratios with dividend yields that reflect current dividend payout ratios for two reasons. Staff submits that growth rates derived from historical data are inconsistent with the prospective nature of the cost of common equity. Staff further notes that Value Line EPS and dividend per share growth data indicate that the average dividend payout ratio for his sample is expected to fall from 2004-2006 to 2010-2012. Staff posits this indicates that the retention ratios (i.e., retention ratio = $1 - \text{dividend payout ratio}$) were lower during the period from which Mr. Thomas derived his $b \times r$ growth rate (2002-2006) than expected going forward, all else being equal. Conversely, it indicates that Value Line projects lower dividend payouts going forward, which would produce a lower dividend yield, all else equal. Staff submits that Mr. Thomas combines the lower retention growth rates from 2002-2006 with the lower current dividend yields, which understates the cost of equity.

Staff opines that numerous studies have shown that analyst growth rate estimates are the best proxy for investor expectations, and that analysts' forecasts are better predictors of actual growth rates than are predictors based solely on historical information. Staff submits the results of valuation models, such as the dividend growth model, are typically more accurate when the growth rate comes from analyst forecasts.

Staff notes that while CUB urges the Commission to adopt its estimates of sustainable growth using the internal growth method, claiming that academic literature concludes that historical growth rates are a far more accurate predictor of expected sustainable growth, Staff submits that the academic literature does not indicate that utility growth rates appear to be upwardly biased or demonstrate that analyst growth rates are poor proxies for investor growth expectations.

c. CUB's Position

CUB suggests the Commission adopt Mr. Thomas' method of computing growth rates, which estimates sustainable growth rate using the internal growth method. CUB submits that Mr. Thomas' analysis avoids reliance on analyst growth estimates and

takes into account changes in expected dividend payout ratios. CUB notes that it, Staff and IIEC agree that analysts' are currently producing overly optimistic growth forecasts that are unlikely to be sustainable over time. CUB submits however, while recognizing that analysts produce overly optimistic growth forecasts, Staff's and IIEC's subjective determination of how growth rates might change is inaccurate, and therefore, should be rejected in favor of the internal growth method.

CUB avers that the sustainable growth rate is a critical component of the DCF model, representing the amount of growth that investors expect to occur on their investment, and that is sustainable over the long-term. CUB submits that setting the growth rate component of the DCF model at an unreasonably high level would result in an estimate of the cost of equity that is also unreasonably high, all other things being equal.

CUB opines that historically, analysts have set their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB asserts that to deal with this problem, Staff and IIEC have adjusted their approach to estimating the cost of equity by using non-constant and two-stage DCF models to account for the optimism of analysts' forecasts. CUB submits that these methods involve significant judgment and introduce a degree of uncertainty into the DCF analysis, which confirms that historical growth rates are a more accurate predictor of expected sustainable growth.

Mr. Thomas addresses both this analyst bias and the bias caused by expected changes in dividend payout ratios, by using the average historic internal growth rate for the sample companies to estimate the sustainable growth rate variable of DCF. CUB says when analysts are expecting the dividend payout ratio to change, their forecasts for both dividends and earnings will not accurately represent expected future growth in the DCF model. Currently, CUB claims analysts are expecting dividend payout ratios to change. Mr. Thomas' estimates of internal growth result in a growth rate of 4.21% for electric utilities and 4.69% for gas utilities. These estimates are considerably below analysts' expected 8.09% growth rate for electric utilities, and 5.20% growth rate for gas utilities. CUB submits that using analysts' growth expectations as the other parties suggest, will overstate the cost of equity.

CUB claims that while AIU argues against Mr. Thomas' use of historic internal growth in the DCF, CUB submits that AIU improperly relies on outmoded and unsupported theoretical arguments. While AIU argues that Mr. Thomas' use of historic internal growth is subjective and has no link to the investor expectations, CUB avers that AIU ignores the most current and relevant academic literature. CUB opines that the latest academic literature supports Mr. Thomas' conclusion that beyond two years, the best forecast of earnings growth is the historical average growth rate.

CUB also disputes AIU's argument that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. While AIU argues that there is an inconsistency because both past achieved returns on equity and Value Line forecasts of future returns are higher than Mr. Thomas' recommendation, CUB submits that this point actually

confirms Mr. Thomas' conclusion. CUB opines that the —Nigel Paper" makes clear historical average earned returns are unreliable as predictors of future returns.

Further, while AIU claims that Mr. Thomas fails to acknowledge that dividend payout ratios have declined, and are expected to decline further, Mr. Thomas' analysis acknowledges declining dividend payout ratios. CUB notes that because dividend growth is uncertain, the DCF formula uses only the current dividend payment (increased by the expected sustainable growth rate), instead of some analyst's estimated or forecasted dividend payment.

AIU further argues that by focusing on internal growth only, Mr. Thomas has failed to consider growth from external financing, which CUB submits is irrelevant. CUB notes that the internal growth method estimates the maximum level of growth that a company can sustain without injecting more capital into the business, which is consistent with the Commission's practice of granting regulated utilities a return on only their prudent and reasonably incurred investments. CUB submits that evaluating external growth is a highly subjective exercise which relies on questionable assumptions about the future and produces results that are inconsistent with the Commission's practice of granting rates that allow the companies to recover their costs during the test year, including pro forma adjustments.

CUB notes that Staff argues that a study by Chan, Karceski and Lakonishok (the "Chan" study) indicates that analyst growth rates for utilities are not overstated. CUB avers that the Chan study did not conclude that the studies Mr. Thomas relied upon were inaccurate, but instead found that low growth companies, such as utilities, did not behave the same as high growth companies. CUB submits that such a result is hardly surprising and does not undermine the finding that historic average growth rates are the best forecast of earnings growth. CUB avers that Mr. Thomas correctly relied upon studies that show analyst estimates beyond two years are inaccurate.

CUB asserts that it has shown that analysts' growth rates are poor proxies for investor growth expectations, and submits that the Commission must measure equity returns that reflect unbiased growth estimates, rather than upwardly biased analyst forecasts that diverge from the achieved growth rates. CUB avers that using analyst forecasts as estimates of growth will overstate the cost of capital estimate produced by the DCF.

CUB avers that Staff is incorrect when it argues that Mr. Thomas failed to acknowledge changes in the dividend payout ratio. CUB submits that as dividend growth is uncertain, DCF uses only the current dividend payment (increased by the expected sustainable growth rate), instead of analysts' estimated or forecasted dividend payment. As analysts' expectations of growth have been shown to be upwardly biased, CUB asserts that the best measure of growth is clearly the historic internal growth that companies in the sample group have actually experienced.

CUB notes that Staff contends that it is inconsistent to apply a growth rate that reflects historic dividend payout ratios with dividend yields that reflect current dividend payout ratios. While Staff argues that a historic perspective has value in forecasting the future, one can not reasonably forecast the future by looking solely to the past. CUB submits that beyond two years, the best forecast of earnings growth is the historic average growth rate. CUB avers that the studies Staff relies on are outdated and have been superseded by more current studies consistent with CUB's arguments.

d. IIEC's Position

IIEC notes that its witness, Mr. Gorman performed and assessed DCF analyses using both constant growth and multi-stage models. IIEC avers that Mr. Gorman rejected the constant growth model as, in his opinion, its results were based on growth rates that are not sustainable. IIEC opines that because of the current environment, Mr. Gorman and Staff witness Freetly both used multi-stage DCF models in developing their cost of equity recommendations.

IIEC notes that AIU witness McShane argues that Mr. Gorman's two-stage model assumes that investors only expect the forecast of growth to continue for precisely five years, with an immediate change thereafter to the long-term growth in the economy, which Ms. McShane avers creates inconsistencies in the DCF cost estimates for the individual companies. IIEC submits that this criticism demands a level of precision not otherwise required (or often seen) in the use of cost of equity models. IIEC avers that analysts regularly assume the validity of a single growth rate input -- in perpetuity -- in the exercise of their expert judgment. IIEC posits that Ms. McShane's criticism is not valid and should be rejected by the Commission.

IIEC submits that should the Commission accept Ms. McShane's criticism that the growth rate transition may not be as precise and immediate as her view of the two-stage model demands, then IIEC suggests at most, Mr. Gorman's two-stage model uses a questionable expected growth input for a 1-3 year period of transition. IIEC notes that the Commission can only surmise at what point investors would expect the analyst's forecast growth rates to decline to levels that more closely track the growth in the economy. IIEC posits that underestimating the period over which the forecast growth rates are expected to prevail understates the cost of equity when the forecast growth rates exceed the long-term equilibrium growth rate and overstate the cost of equity when the converse is the case. IIEC submits that giving equal weight to the constant growth and two-stage DCF models is not a reasonable approach, under these circumstances.

While AIU contends that it is not reasonable for IIEC to discard the results of the constant growth test, IIEC notes that AIU admits that —~~the~~ growth rates analysts are forecasting are not sustainable in the long-term," as is required for a constant growth DCF model. IIEC notes that Mr. Gorman's decision not to use a constant growth DCF model was the result of a detailed evaluation of the reliability of that model in the current environment. Mr. Gorman posits that near term analysts' growth estimates are too high

to be sustainable as long-term growth rates, similar to Staff's conclusion on this issue. Although AIU alleges that Mr. Gorman has changes his analyses from prior cases, IIEC submits that Mr. Gorman's consistent practice is to test analysts' growth rates to determine whether they are appropriate for use in a constant growth DCF model. Like Staff, Mr. Gorman found current market circumstances did not produce reliable and accurate results in a constant growth DCF model. IIEC submits that AIU presented no credible evidence that a constant growth DCF model using those analyst's near term growth rates that Mr. Gorman rejected would produce a reasonable return estimate. IIEC submits that Mr. Gorman's two stage DCF analysis is appropriate given current circumstances and should be adopted by the Commission.

4. CAPM Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Toward that end, Staff witness Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. Staff notes that in the CAPM, the risk factor is market risk, which can not be eliminated through portfolio diversification. IIEC and AIU also utilized the CAPM in there cost of equity analyses while CUB suggests there are significant problems with the CAPM.

a. CUB's Position

CUB submits that recent financial literature reveals CAPM contains a substantial bias, which renders it unreasonable to rely on to estimate a utilities cost of equity. CUB notes that a 2007 study it identifies as the —Nagel Paper,” casts doubt on whether CAPM provides a better estimation of the cost of capital than a completely arbitrary model. CUB submits that the Nagel Paper is the most recent research available on forecast error in CAPM, and corroborates a long history of problems with CAPM.

CUB submits that the Nagel Paper compared a simplified version of CAPM to the mainstream version of CAPM, and five other well-known theoretical models, and concludes that forecast error caused by estimating factor loadings and expected risk premiums in the more complex models exceeds the precision gained by including the risk factors. CUB posits that despite this evidence that CAPM is inaccurate, Staff continues to recommend averaging CAPM results with DCF results to obtain a final recommendation for cost of equity.

CUB recommends that the Commission consider the evidence presented in this case and reject its previous method of averaging DCF and CAPM results to find a final return on equity recommendation. CUB recommends instead using a DCF calculation to estimate return on equity, and suggests the Commission adopt CUB's DCF result of 8.955% for AIU's gas distribution operations and 9.046% for AIU's electric distribution operations.

b. Staff's Position

Staff notes the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly combined betas from Value Line and a regression analysis to estimate the beta of the Gas and Electric samples. For the gas sample, her average Value Line beta estimate was 0.88, while her regression beta estimate was 0.74. For the electric sample, the average Value Line beta estimate was 0.83, while the regression beta estimate was 0.77. For the risk-free rate parameter, Ms. Freetly considered the 2.53% yield on four-week U.S. Treasury bills and the 4.72% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of February 14, 2008. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.4% and 5.6%. Staff notes that following her analysis, Ms. Freetly concluded that the U.S. T-bond yield is currently the superior proxy for the long-term risk-free rate. Finally, for the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market was 13.75% for the fourth quarter of 2007. Staff submits that after inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 12.04% for the gas sample and 11.94% for the electric sample.

5. Beta

a. Staff's Position

Staff notes that CUB challenges Staff witness Freetly's beta. Staff claims that Ms. Freetly's methodology used to calculate the regression betas for her sample has been approved by the Commission in previous dockets. (Docket No. 02-0837, Order at 37-38; Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 85; Docket No. 00-0340, Order at 25; Docket No. 03-0403, Order at 42) The Order in AIU's last rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), states:

As the Commission understands it, the Staff regression betas have been calculated in the same manner for several years and, with rare exception, have formed in part the basis for Commission approved returns on common equity. Just as the Commission routinely relies upon both the DCF and CAPM, the Commission believes it is reasonable to rely upon both Value Line and regression betas. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 145)

While Staff notes that CUB witness Thomas claims that betas should not be adjusted for reversion to a market mean of 1.0, Staff submits that the Nagel Paper that he cites actually contradicts his argument and found that a CAPM using raw betas is less accurate in predicting realized rates of return and explicitly rejected use of an unadjusted beta. Staff posits that while the beta parameter is generally derived from

historical data, as in theory it should be a forward-looking number, Staff adjusted the raw (i.e., historical) betas for the sample companies to improve the accuracy of the beta estimates. Staff submits that the Armitage text Mr. Thomas cites with regard to this argument indicates that studies have shown that such adjustments result in appreciably better forecasts, finding that the reduction in both bias and inefficiency is greater the further away from one the beta in question is. Staff notes that Armitage states that the observed flatness of the Securities Market Line is due to two factors: 1) error in the estimation of true betas (i.e., the further above (or below) the mean an observed beta is, the more likely it is that the estimate error is positive (or negative)) and 2) regression toward the mean (i.e., moderation in risk over time).

While Mr. Thomas concludes that mean reversion for utilities with betas below 1.0 is wrong, citing a Gombola and Kahl article that suggests that utility betas actually revert to a utility average beta rather than a market mean beta of 1.0, Staff submits the derivation of the true industry mean beta is problematic. Staff avers that not only is any estimate of the true industry portfolio beta mean dubious, as betas change over time, but notes the farther below the market mean a raw beta is, the more likely its estimate error is to be negative. Staff posits that the average of a portfolio of low betas, each of which is likely to be biased downward, will, itself, likely be biased downward. Staff submits that Mr. Thomas' proposal to ignore beta reversion altogether and use an unadjusted beta was explicitly rejected in the Nagel Paper, and should be rejected by the Commission in this proceeding.

b. CUB's Position

CUB argued that the evidence presented in this case shows that CAPM is highly inaccurate, and suggested the Commission reject any rate of return that includes CAPM in the calculation. CUB submits that should the Commission use CAPM in setting the return on equity, the Commission should reject Staff's and IIEC's CAPM analyses as they use adjusted betas that result in even greater inaccuracies.

CUB notes that the beta parameter represents the degree to which the price of a stock moves with the overall market, and if the stock in question is less volatile (and hence, less risky) than the overall market, then its beta parameter will be less than 1.0, while if the stock is more volatile and risky than the overall market, then its beta parameter will be greater than 1.0. CUB submits that in the context of a CAPM analysis, an unreasonably high choice of beta parameter will result in an unreasonably high cost of equity.

CUB avers that while the Commission has historically relied on beta parameters that have been adjusted using the mean reversion adjustment, this adjustment is reasonable only under certain circumstances – when a company's beta can be expected to move toward 1.0 over time. CUB submits that utility stocks have not been shown to have beta parameters that move toward 1.0 over time, and argues that financial researchers have found that an underlying mean of 1.0 is too high for most utilities, and theorizing that utilities revert to a utility average beta.

While Staff attempts to refute this evidence by arguing that a portfolio of betas below 1.0 will be biased downward, CUB avers that Gambola and Kahl have already proven that the mean reversion adjustment methodology does not apply to utilities, and there is no basis with which to conclude that a portfolio of utility betas will somehow behave any differently than individual utility betas. CUB submits that the mean reversion adjustment incorrectly increases CAPM estimates of utility cost of equity, is inappropriate for use in a utility rate making proceeding, and should be rejected by the Commission.

c. IIEC's Position

IIEC posits that in recent years, electric utilities have implemented corporate strategies that have decreased their operating and financial risk factors. Specifically, they have pursued back-to-basics investment strategies that lower their operating risks, and they have divested non-regulated businesses to reduce debt and strengthen their balance sheets. IIEC submits that these trends are confirmed in the published observations of capital industry institutions like Value Line, which notes an increase in the common equity ratio and fixed charge coverage ratio of such utilities over the last three to five years, further lowering financial risk. IIEC avers that these risk reductions have resulted in robust stock return performance for electric utility stocks.

Mr. Gorman observed that over the last five to ten years, utility betas have exhibited an upward trend that is not associated with an actual increase in risk, rather, the apparent increase indicated by the high betas reflects that utility stocks have outperformed the market. Recognizing these market developments, Mr. Gorman employed a beta of 0.85 in his CAPM analysis, which IIEC submits is appropriate and should be adopted by the Commission.

6. Expected Risk Premium

a. AIU's Position

AIU submits that Mr. Gorman's CAPM takes an improper approach to estimating the market risk premium. AIU notes that he estimates the market risk premium in two ways. For one method, he adds the average historic real return on equities to the long-term forecast of inflation to arrive at an estimate of the future market return of 11.6%. From that estimated market return, he subtracts the forecast risk-free rate of 4.6% to arrive at an estimated market risk premium of 7.0%. His second approach takes the nominal historic return on equities from which he subtracts the historic achieved total return on government bonds (5.8%), arriving at a market risk premium of 6.5%.

AIU asserts that with respect to the first approach, adding the real return achieved on the market to expected inflation would be appropriate if there were any evidence that the expected return on the market moves in tandem with the rate of inflation, however AIU posits that there is no such evidence. AIU submits that in the

absence of any observable relationship between inflation and real returns, or any indication that there is any secular upward or downward trend in the nominal market returns, the nominal achieved market return is the better estimate of the forward looking market return. AIU notes that the nominal market return, as utilized in Mr. Gorman's second approach, is 12.3%, leading to a market risk premium over his 4.6% forecast risk-free rate of 7.7%.

AIU avers that Mr. Gorman's second approach to estimating the market risk premium entails subtracting the historic total return on government bonds (income return, capital appreciation return and investment return) from the total return on the equity market composite. AIU notes that the estimation of the market risk premium, requires the use of a proxy for the risk-free rate, and submits the total return achieved on government bonds is not the appropriate proxy for the risk-free rate, but instead the income return, not the total return, on bonds should be used as the proxy for the historical risk-free rate when estimating the expected market risk premium ("EMRP").

AIU posits that another consideration when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. AIU notes that the total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow, the capital appreciation return results from the price change of a bond over a specific period, while the reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. AIU submits that the income return is used in the estimation of the equity risk premium as it represents the truly riskless portion of the return.

While Mr. Gorman contends that using total returns on stocks while using income returns on bonds is a mismatch, AIU avers that this is not the case. AIU submits that it is appropriate to use income returns on bonds as the estimate of the ex ante expected risk-free rate while simultaneously using total returns on equities to estimate the expected return on the market. AIU argues there are no observable secular trends in the equity market returns that suggest the equity market returns are not a reasonable reflection of investor expectations, and there is no reason that the total returns on the equity market would not be used by investors to estimate the market risk premium relative to the risk-free rate.

AIU posits that the use of the income return of 5.2% instead of the total return on long-term Treasury bonds of 5.8% results in an equity risk premium of 7.1% ($12.3\% - 5.2\%$), and the average of the two revised market risk premiums is approximately 7.4%, compared with Mr. Gorman's estimate of 6.75%. AIU submits this results in CAPM return on equity of 10.9% ($4.6\% + 0.85 \times 7.4\%$), rather than Mr. Gorman's calculated 10.4%.

b. Staff's Position

Staff notes that IIEC witness Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%.

Staff submits that historical risk premiums do not adequately measure investors' current return requirements as historical risk premiums are based on realized returns. Staff avers that due to unpredictable economic, industry-related or company-specific events, the difference between realized and expected returns can be substantial. As such, Staff suggests the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Further, the magnitude of the historical risk premium depends upon the measurement period used. Staff suggests no proven method exists for determining the appropriate measurement period, and therefore historical earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity.

Staff notes the Commission has consistently rejected use of historical data in determining the market risk premium in setting the investor-required rate of return on common equity, and submits the Commission should do so once again in this proceeding. In AIU's most recent rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission rejected Ms. McShane's estimate of the market risk premium and stated:

The Commission observes that earned returns on equity are different than expected returns on equity and that the former can not be used to estimate the latter. Additionally, the Commission believes that it would be all too easy to select a historical period that produces a biased result, whether upwardly biased or downwardly biased. As it has done in numerous previous rate cases, the Commission rejects this type of approach to estimating the forward looking cost of common equity. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 142-143)

Staff notes that Mr. Gorman claims Staff's market risk premium estimate is overstated due to Ms. Freetly's DCF derived return on the market, which he claims reflects a growth rate of 11.2%. Although Mr. Gorman presents market risk premiums over long historical periods as measured by Morningstar to indicate that Ms. Freetly's Market risk premium is inflated, Staff submits that historical market risk premiums do not

indicate the additional risk premium that common equity investors are expecting in today's market.

Staff suggests that while IIEC claims that the market risk premium presented by Staff is flawed and less reliable than Mr. Gorman's estimated market risk premium range, his calculation of Staff's growth rate does not factor in stock repurchases. Staff posits that Mr. Gorman's failure to consider stock repurchases in his calculation of growth produces an incorrect estimate of the growth rate implied in Staff's calculation of the market risk premium.

Staff avers that CUB witness Thomas presents academic research indicating that the proper expected common equity market risk premium for determining the investor-required rate of return is between 3 and 5%. Staff submits that the research cited represents various academics' opinions of the common equity risk premium investors should expect, not necessarily what the investors truly are expecting. Staff suggests that since the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward, therefore Staff's estimate of the common equity risk premium, derived by subtracting the current yield on long-term U.S. Treasury bonds from the required return on the S&P 500 provides the actual difference between returns on risk-free and risky securities that exists in today's market.

Staff argues that its estimate of the market risk premium provides the actual difference between returns on risk-free and risky securities that exists in today's market, providing the best indication of what investors can expect going forward, and should be accepted by the Commission.

c. CUB's Position

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB notes the EMRP represents the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate. CUB submits the EMRP should be the same for all markets and for all firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk.

Despite the fact that the EMRP should be the same for all markets and firms, CUB argues the other parties in the proceeding use biased analyst estimates of the EMRP using forecasted growth. CUB posits that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP, 5.0%. CUB submits that Mr. Thomas relied on research from independent academics and investors to arrive at his conclusion that analyst-calculated EMRPs often contain significant upward bias. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%.

CUB notes that Staff calculated EMRP using analysts' forecasted growth rates in a DCF analysis of companies making up the S&P 500, which forecasts CUB argues have their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB submits the Commission should rely on the greater base of empirical data on which the published studies report and should the Commission use CAPM, use an EMRP of 5.0% in the CAPM.

CUB notes that while Staff argues that Mr. Thomas' EMRP estimate is inaccurate because the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time and thus current returns provide the best indication of what investors are expecting going forward, CUB submits EMRP is a characteristic attributable to all investors and applies to the full universe of all potential investments. CUB argues the Commission should not ignore available research that confirms that expectations of the EMRP are far below the level that Staff recommends and the EMRPs that have traditionally been approved by the Commission.

d. IIEC's Position

Mr. Gorman made two estimates of the market risk premium for use in his CAPM study. First, he relied on Morningstar data to estimate the actual historical achieved total return on the stock market versus the total return on long term Treasury bond investments. That analysis indicated a market risk premium of 6.5%. Mr. Gorman also used a risk premium study to estimate the forward-looking return on the market less his estimated risk-free rate to produce a market risk premium of 7.0%.

In support of his market risk premium estimates, Mr. Gorman cited actual market data compiled by Morningstar Ibbotson as support for a market risk premium in the range of 6.23% and 7.05%. IIEC avers that Ms. Freetly developed market risk premium estimates using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium estimate of 9.03%. IIEC notes that Ms. Freetly's DCF market return is based on a risk-free yield of 1.9% and growth rate of 11.2%. IIEC submits that the market risk premium estimation alternative presented by Ms. Freetly is flawed and less reliable than Mr. Gorman's as the growth rate estimate in her market based DCF return studies are too high to be used in a constant growth DCF study.

While Ms. Freetly's proposed alternative market risk premium is based on her DCF estimate of the market return, IIEC avers that her result reflects an implicit growth rate (over 11.5%) that simply is not reasonable. IIEC submits the sustainable growth rate for a utility can not plausibly be estimated to exceed the growth rate of the economy in which it operates. IIEC says that assuming growth rates twice the gross domestic product ("GDP") growth rate produces market risk premium results that exceed reasonable estimates like Mr. Gorman's.

Both Ms. Freetly and Ms. McShane challenge the historical market data cited by Mr. Gorman to support his contention that the market risk premium estimates they used

are excessive. Ms. McShane contends that the studies are not, in fact, adopted by Morningstar Ibbotson as the estimate of the market risk premium and, as a result, Mr. Gorman's estimate of the market risk premium should be on the order of 7.4%. IIEC submits that whether the Morningstar data were adopted is irrelevant, as Mr. Gorman did not use the data as mere plug-in inputs to his models. IIEC posits that the data represent actual investment returns that Morningstar collected, analyzed and published which Mr. Gorman relied on as this data is useful to investors in forming their expected returns. IIEC argues that Ms. McShane's argument is essentially that the data collected and published by a market institution was, in this instance, useless; which IIEC submits is not a credible argument.

IIEC notes that while Ms. Freetly criticizes any use of historical data to develop expectations for the future, including in expected risk premium analyses, IIEC submits that a CAPM analysis is, in fact, a risk premium analysis that estimates a beta factor from historical data. IIEC avers that Ms. Freetly relies on this risk premium study, including the beta derived from historical data, to support her recommended return for AIU in this case. IIEC argues that Ms. Freetly was unable to deny that her market premium determination is based on a DCF market return estimate that reflects an unsustainable growth rate more than twice the expected long-term growth rate of the national GDP. IIEC posits that her forward-looking market DCF return is inflated and unreliable, which in turn makes her CAPM market risk premium unreliable and flawed. IIEC avers that if Ms. Freetly's CAPM is corrected to reflect a reasonable market risk premium, her analysis also would support a return on equity of less than 10.0%.

IIEC notes that AIU takes issue with Mr. Gorman's EMRP estimate used in his CAPM analysis, arguing that the total return achieved on government bonds should not be used as the appropriate proxy for the risk-free rate. IIEC posits that for bonds held to maturity; which IIEC argues is a precondition to long-term yields; the subsidiary return components on which AIU focuses are not a factor. IIEC notes that capital appreciation and reinvestment income, which AIU argues are not risk free, are realized only if the bond is not held to maturity, and they disappear when the bond fully matures.

While AIU also takes issue with Mr. Gorman's reliance on the historical real return on the market combined with a forward-looking inflation expectation to estimate EMRP, arguing it would be more appropriate to use the nominal actual achieved return on the market (12.3%), IIEC asserts it is more appropriate to create a forward-looking expected return on the market as Mr. Gorman did. IIEC notes that the nominal return on the market Ms. McShane uses reflects historical inflation, while Mr. Gorman's forward-looking expected return on the market reflects forward-looking inflation outlooks and is incorporated in the market's current valuation of securities.

IIEC claims that while Mr. Gorman's method of estimating an expected return on the market does rely on historical data and forward-looking market expectations, this is a widely accepted methodology. IIEC submits that Ms. McShane and Ms. Freetly, in their own CAPM studies, relied on historical data adjusted for forward looking expectations, using Value Line betas and betas calculated using historical stock prices.

IIEC avers that in each case, the beta is estimated from a regression of historical data on stock price variability in relationship to the market price variability, then adjusted to reflect forward-looking risk expectations.

While AIU argues that Mr. Gorman's market risk premium is inconsistent with the historical data and analysis both analysts used, IIEC notes that for her comparison to Mr. Gorman, Ms. McShane relied exclusively on the highest estimated return from the data and a market risk premium of 7.1% while Mr. Gorman used data from Morningstar. IIEC avers that Morningstar indicates that an EMRP reflecting sustainable valuation results can range from 6.2% to 7.1%, depending on the market index used. IIEC submits there is no basis for AIU's argument that only Morningstar's highest market risk premium estimate should be used to estimate AIU's return on equity in this proceeding. IIEC avers that these same arguments apply to Staff's criticism of Mr. Gorman's analysis.

7. Risk Premium Model

a. AIU's Position

AIU notes that IIEC witness Gorman estimates the equity risk premium by averaging the results of two approaches. In the first, the differentials between the regulatory commission authorized rates of return on equity and the yields on long-term U.S. Treasury bonds for the period 1986-June 2007 are determined. Using the 5.2% mid-point of a range of differences of 4.4% to 5.9% (in which 18 of his 22 observations fall), he adds his forecast 30-year Treasury bond yield of 4.6% to arrive at a return on equity of 9.8%. Mr. Gorman's second risk premium approach adds a utility risk premium over utility bonds of 3.7% (mid-point of a range of 3.0% to 4.4%) to the 13-week average yield on Baa rated utility bonds for the period ending February 22, 2008 of 6.5%, producing a cost of equity of 10.2%. The two models are given equal weight, for a return on equity of 10.0%.

AIU submits that Mr. Gorman has incorrectly estimated the risk premium. AIU posits that using regulatory commission authorized returns as the point of departure does not constitute an independent test of the required return on equity; and even assuming that the allowed returns equate to the cost of equity, it is inappropriate to simply average the results for the entire period 1986-June 2007. AIU avers that this approach fails to recognize that there is an inverse relationship between interest rates and equity risk premiums, and use of this approach understates the required risk premiums in the current and forecast interest rate environment.

AIU notes that the required risk premium at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% was estimated from Mr. Gorman's data through a simple regression analysis using the indicated historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. AIU posits that the results indicate that the equity risk premium implicit in the regulatory authorized returns on equity increases (decreases) by 39 basis

points for every one percentage point decrease (increase) in the long-term Treasury bond yield.

AIU submits that based on the relationship described above, the equity risk premium and the indicated return on equity at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% is as follows: the indicated risk premium is 5.8% and the indicated return on equity is 10.4%, compared to Mr. Gorman's result of 9.8% calculated using simple average risk premiums.

AIU avers that this same problem exists with Mr. Gorman's risk premium over utility bond yields. At Mr. Gorman's 6.5% utility bond yield, the indicated risk premium is 4.2%, rather than the 3.7% he relied on, for a return on equity of 10.7%, an increase of 0.5% from his reported result of 10.2%.

AIU notes that Mr. Gorman's risk premium test estimate is the simple average of the results of the risk premium over Treasury bond yields and the risk premium over utility bond yields models, and the average of the two revised versions of the models is 10.6% (compared to Mr. Gorman's 10.0%).

b. IIEC Position

In his development of Risk Premium cost of equity estimates, Mr. Gorman used two distinct estimates of the market risk premium to define the range of that factor. The first estimate was based on the difference between the commission authorized returns on common equity and Treasury bond yields, the second on the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields. Mr. Gorman's risk premium analyses produce a return estimate in the range of 9.8% to 10.2%, with a midpoint estimate of 10.0%.

Mr. Gorman avers that his estimated range for the utility equity risk premium is consistent with risk premiums actually found appropriate over a period of almost three decades, adjusted as indicated by prevailing utility bond to Treasury bond spreads. Mr. Gorman asserts that his use of a range of utility equity risk premium estimates, as opposed to a spot estimate, best takes into account the unpredictable variance in the risk premium stemming from changes in investor perception and market conditions.

IIEC posits that while Ms. McShane argues that an inverse relationship between bond prices, inflation and corresponding equity investments needs to be recognized in IIEC's risk premium analysis, IIEC does not agree. While Ms. McShane argues that current lower interest rates mean that the risk premium from Mr. Gorman's analysis should be increased, IIEC suggests this is a simplistic correction for a relationship that is neither simple nor unchanging.

As Ms. McShane recognizes, Mr. Gorman's risk premium test covers a period which has been characterized by both high and low inflation. IIEC submits that his study directly takes account of the unpredictable variances in actual movements of

interest rates as well as equity returns, and as it covers a long period, his analysis avoids giving undue influence to possibly anomalous periods. IIEC notes this smoothing effect is supplemented by Mr. Gorman's consideration of current indicators, which gives emphasis to periods that may have more investor influence, as Ms. McShane states is appropriate.

With respect to Mr. Gorman's Risk Premium cost of equity estimate, AIU argues that Mr. Gorman —fail~~so~~ to recognize that there is an inverse relationship between interest rates and equity risk premiums” and that he —~~thus~~ understates the required risk premiums in the current and forecast interest rate environment.” IIEC says AIU witness McShane based this conclusion on her regression analysis using historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. IIEC claims the relationship between interest rates and equity risk premiums is not constant, may be positive or negative, and can not be predicted with certainty. Consequently, analyses like Ms. McShane's are sensitive to the period from which data are taken. Despite the academic research showing a changeable interest rate/risk premium relationship, IIEC claims AIU has provided no evidence that the alleged inverse relationship actually exists today. IIEC submits that the most important attribute of the alleged relationship, for AIU, is that it increases the risk premium and inflates the return on equity estimate.

IIEC submits that Mr. Gorman's equity risk premium was derived from data that avoids the unpredictability of the interest rate/equity risk premium relationship. Using Treasury/utility bond yield spreads to track contemporaneous investment risk differences between equity securities and debt securities, Mr. Gorman used this analysis to gauge whether the equity risk premium used in this case should be at, above, or below the average historical level. IIEC notes that Mr. Gorman's analysis was based on a measure of investors' market risk assessments, and not on an inference of investors' assessments, from the unreliable inverse relationship with interest rates.

8. Adjustment for Reduced Risk of Gas Operations

a. AIU's Position

AIU notes that IIEC recommends a downward adjustment to its recommended return on equity of at least 0.50% if the riders proposed by the AIU are adopted by the Commission. AIU submits that this recommendation is purely speculative and Mr. Gorman has provided no indication of whether other utilities in his sample might already have access to similar riders. AIU submits that the proposed QIP rider is to the benefit of customers, not only because it will result in required infrastructure, but because it will reduce the regulatory costs and burden of serial rate proceedings that might otherwise be required, and therefore Mr. Gorman's downward adjustment should be rejected.

AIU also disagrees with CUB's recommendation to reduce the return on equity by 67.5 basis points if the VBA rider is approved for the gas distribution operations. AIU posits that CAPM, to which the Commission has traditionally given significant weight,

does not provide investors compensation for weather risk, and provides compensation for non-diversifiable risk only. AIU submits that weather is a diversifiable (company-specific) risk. AIU claims that seven of the eight gas distribution utilities in Ms. McShane's sample have partial or full weather protection, thus, any risk-reducing impact of the weather protection on the required return on equity is already reflected in DCF cost of equity estimates.

AIU notes the CUB witness Thomas attempts to place a value on the AIU gas distribution operations' associated with proposed Rider VBA by "backcasting" the increase in return on equity that the utilities would have experienced between 2002/2003 (prior test years), and 2006, had Rider VBA been operational. AIU notes that Mr. Thomas estimates that with Rider VBA, the actual returns on equity would have been on average 221 basis points higher. As Mr. Thomas notes that the earlier test years were based on 30-year normal weather, while AIU is proposing rates now be set on 10-year normal weather, he attempts to adjust the 221 basis points for the proposed change in weather normalization methodology. AIU avers that Mr. Thomas calculated that AIU's estimated reduction in the variance of heating degree days from normal that is expected to result from switching from 30-year to 10-year normal weather will translate into a similar reduction in the impact that Rider VBA would have on return on equity. AIU submits that Mr. Thomas then reduced the 221 basis point impact to 142 basis points. To account for other factors, AIU notes that Mr. Thomas recommends that the allowed return on equity be reduced by 67.5 basis points.

Mr. Thomas' analysis of the impact on return on equity from moving from 30-year to 10-year normal weather assumes that the 35.85% decline in heating degree day deviations translates into an identical percent reduction in the impact of the Rider VBA on return on equity. AIU submits that Mr. Thomas fails to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced, which AIU claims would have changed the delivery rates required to recover the revenue requirements established for the 2002/2003 test years.

AIU submits that the following table summarizes the average customer usage reflected in the development of residential rates for the 2002/2003 test years compared to the proposed average customer usage based on the 2006 test year.

<u>Company</u>	<u>2002/2003</u>	<u>2006</u>
AmerenCILCO	946	823
AmerenCIPS	899	767
AmerenIP	904	779

While some of the change would have been due to ongoing conservation, AIU submits the majority of the reduction is due to the switch from 30-year to 10-year normal weather. AIU asserts that if the average customer usage proposed in this proceeding had been used to set the delivery rates required to recover the 2002/2003 revenue requirement, the outcome of Mr. Thomas' analysis would have been significantly

different. Ms. McShane compared Mr. Thomas' estimates of the impact of Rider VBA on return on equity from the residential classes only to the impact that would have resulted had 2002/2003 delivery rates been set using 2006 test year average customer usage. While Mr. Thomas' analysis produced an average increase in return on equity of 147 basis points had Rider VBA been applied only to the residential rate class, AIU posits that the replacement of the 2002/03 average customer usage with the 2006 test year average customer usage shows that the average return on equity would have decreased by 64 basis points. This suggests to AIU that it would have refunded money to customers, rather than recovering money from customers. AIU submits that while there would have been some decline in average customer usage from conservation since 2002/2003, the impact of Rider VBA would have been negligible.

AIU avers that while Mr. Thomas makes the assumption that the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA translates into a similar reduction in required return on equity, his assumption has no theoretical or empirical basis. AIU notes Ms. McShane's analysis suggests that AIU would have owed customers money if Rider VBA had been in place, while following Mr. Thomas' logic, the cost of equity should increase, which AIU submits does not make sense.

b. Staff's Position

Staff notes that Ms. Freetly did not incorporate the lower risk associated with the Rider VBA revenue decoupling mechanism that AIU proposes in her cost of equity recommendation for the natural gas distribution operations of AIU. Staff submits Rider VBA would effectively separate the gas utility's fixed cost recovery from the amount of gas that it sells, which would result in actual utility revenues that more closely track its projected revenue requirements and should not change with increases or decreases in sales. Staff avers this would give AIU greater assurance that the authorized rate of return will be earned. Staff notes that Moody's states that rate designs that compensate the gas utility for margin losses caused by conservation and weather-related variations in gas consumption stabilize the utility's credit metrics and credit ratings. Staff submits that as the use of a gas decoupling mechanism would reduce risk to a gas utility, a downward adjustment to the rate of return on common equity is appropriate to recognize the reduction in risk associated with the use of a decoupling mechanism.

Staff avers that Moody's analysis of gas utilities focuses on four core rating factors: sustainable profitability, regulatory support, ring fencing, and financial strength and flexibility. Staff submits that among the risk factors reflected in return on equity is the utility's ability to increase earnings despite customer gas conservation, and adoption of a gas decoupling mechanism in a utility's rate design would lower the risk of the utility not achieving the authorized return on equity. Moody's assigns the return on equity factor a 15% weight in determining the overall credit rating score.

Regulatory support considers the strength of the utility's relationship with the regulatory commission. Staff avers that Moody's states that the ability of the utility to

recover allowed expenses in a timely manner and its ability to earn its authorized rate of return is a very important component of the utility/regulator relationship. Staff posits a utility's score on this factor would be improved with approval of a gas decoupling mechanism since its ability to earn its authorized rate of return would be enhanced. Moody's assigns a 10% weight to the regulatory support factor when determining the overall credit rating score.

Staff notes that although Moody's does not identify the precise impact that revenue decoupling would have on these two factors, enhancing the utility's ability to earn its authorized rate of return would be viewed favorably and could increase the scores assigned to the return on equity and regulatory support factors. Hence, Ms. Freetly assumed that the credit ratings assigned to each of these factors would improve by one credit rating. Since these two factors comprise 25% of the overall weighting, raising the scores for these two factors by one rating would result in a one notch increase in the overall credit rating (i.e., $25\% \times 3 = .75$ rounded to 1). Consequently, if the rating assigned to the return on equity and regulatory support factors is raised by one rating, the overall credit rating for the utility would advance by almost one notch. Staff argues that if the overall credit rating for a company is Baa1 before revenue decoupling, it would most likely improve to A3 with commission approval of a decoupling mechanism. Staff notes the average Moody's credit rating for Staff's gas sample is Baa1, and the spread between utility bonds rated Baa1 and A3 is 10 basis points. Therefore, Staff recommends that the return on common equity for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP be reduced 10 basis points should the Commission approve Rider VBA to recognize the reduction in risk associated with the use of a gas decoupling mechanism. In the event the Commission approves Rider VBA, the referenced cost of equity adjustment will necessarily result in a reduction to Staff's cost of equity recommendations for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP.

Staff asserts that Rider QIP would also affect the risks and costs of capital of AIU. First, Staff explains, Rider QIP would effectively create two classes of assets from a risk perspective: rate base and Rider QIP assets. Since the riskiness of those two classes of assets could be very different, Staff recommends that the Commission authorize a different rate of return for Rider QIP assets than it authorizes for rate base. Staff does not believe that Rider QIP assets would affect the risk of rate base assets; therefore, Staff does not recommend any adjustment to the authorized rate of return on rate base should the Commission approve Rider QIP.

According to Staff, Rider QIP's affect on AIU's risk (and thus the costs of capital) is a function of how it would operate. Staff is proposing modifications to Rider QIP in the event the Commission approves such an infrastructure rider. Nevertheless, Ms. Freetly addresses how certain elements of the rider would affect risk. Staff maintains that a downward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would reduce risk, while an upward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would increase risk.

Staff notes that in comparison to rate base cost recovery, the recovery of the capital costs of projects run through Rider QIP would be more timely. All else equal, Staff states that this reduction in regulatory lag reduces the risk of Rider QIP projects. Should Rider QIP be approved, Staff is further proposing that the rider include a true-up, which Staff submits would increase the probability that the utility will recover all Rider QIP costs, including a return on the capitalized costs, relative to rate base costs. Staff contends that this increased certainty of more timely cost recovery would decrease the risk of Rider QIP projects. Staff submits that nothing in Rider QIP would require AIU to share operating cost savings with customers, which would also reduce the risk of Rider QIP. Staff however is also proposing that the QIP rate be capped so that recovery of the QIP adjustment is discontinued if the utility is earning above the authorized rate of return, which feature would increase the risk of Rider QIP projects because it effectively constrains upside earnings variability of rate base.

Staff indicates that the risk implications of the four Rider QIP components discussed above are cumulative. Therefore, should the Commission: (1) adopt Rider QIP, (2) include a true-up mechanism, (3) not include a pass-through of operating cost savings, and (4) include an earnings cap, Staff contends that four separate adjustments to the Rider QIP cost of common equity would be appropriate. Staff states that the first three adjustments should each reduce the Rider QIP cost of common equity, while the last adjustment should increase the Rider QIP cost of common equity. Staff does not recommend specific cost of common equity adjustments, although Staff agrees that Rider QIP projects would be less risky than projects whose costs are not recovered through a rider, the record contains no analysis-backed quantification of that risk reduction and its effect on cost of capital.

c. CUB's Position

CUB notes that AIU proposes several new riders as part of its filing, and while CUB urges that both Riders VBA and QIP be rejected by the Commission, should the Commission allow either Rider, the Commission should recognize that these riders have an effect on the riskiness of AIU that must be reflected in rates. CUB says that if the Commission chooses to approve Rider VBA, the Commission should reduce AIU's cost of equity by 67.5 basis points. If the Commission approves Rider QIP for AIU's electric operations, CUB argues the Commission should allow AIU to recover only its embedded cost of long-term debt on projects financed under this rider to adjust for the reduced risk AIU has when making such investments.

CUB opines that Rider VBA was proposed to protect AIU and its investors from deviations in monthly sales due to fluctuations in normal weather conditions and reduced customer demand, thereby reducing the risk that AIU will realize revenues below its approved revenue requirements. CUB submits this rider also minimizes shareholder risk due to future reductions in customer demand caused by weather and declining per customer usage, and would also reduce overall operating risk that arises

from regulatory lag. CUB argues that these changes are designed only to benefit shareholders, and are simply not necessary to assure AIU's financial stability.

CUB submits the benefits of Rider VBA accrue directly to AIU's common equity shareholders, as Rider VBA would provide revenue stability, and enable AIU to increase earnings in the future. CUB submits that the evidence demonstrates that the impact of VBA during 2003 and 2006 would have been to increase the total AIU gas operation return on equity by between 16 and 385 basis points, with an average impact of 221 basis points. CUB submits that the value of Rider VBA to AIU's shareholders is much greater than the arbitrary 10 basis points reduction the Commission granted to Peoples for a similar rider. Should the Commission approved Rider VBA, CUB suggests AIU's return on equity should be reduced by 67.5 basis points, which CUB submits is less than half of the impact of Rider VBA, and is less than the impact that weather normalization alone is likely to have on variability in AIU's return on equity.

CUB notes that while AIU argues against Mr. Thomas' recommendation to reduce its gas distribution return on equity by 67.5 basis points for Rider VBA, CUB posits that AIU inadvertently supports Mr. Thomas' argument that the CAPM is an unreliable model, when it argues that in principle, CAPM does not evaluate weather risk. CUB posits that Rider VBA will produce more stable and certain cash flows that will translate into increased confidence that investors will receive their required return, however, this decreased riskiness is not captured directly in CAPM framework. CUB submits that CAPM's failure to evaluate this significant driver of investor returns substantiates Mr. Thomas' conclusion about the limited worth of the model.

CUB notes that AIU also argues that, because seven of the eight gas distribution utilities in its witness' sample have partial or full weather protection, any risk-reducing impact of the weather protection on the required return on equity is already reflected in the DCF cost of equity estimates. CUB submits that the Commission rejected a similar argument in the recent Peoples rate case, Docket Nos. 07-0241, 07-0242 (Cons.).

CUB avers that AIU argues that Mr. Thomas' quantitative analysis of the impact of Rider VBA is inaccurate, failing to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced. AIU argues that had Rider VBA and 10-year weather normalization both been in place for the residential class during 2002/2003, Rider VBA would have resulted in rate credits rather than surcharges. CUB notes however, that AIU witness Laderoute's schedule 14.3 shows there has been a marked decline in the 10 year moving average of heating degree day data for central Illinois since the late 1990's. CUB submits that using 10-year weather normal in 2002 would have resulted in per customer usage higher than AIU has proposed in the 2006 test year. CUB avers that to assume that the lower 2006 usage levels approximate normal in 2003 makes little logical sense, and renders Ms. McShane's analysis useless to the Commission. CUB notes that in addition, Ms. McShane's analysis ignores the impact that Rider VBA would have on the small commercial class, a feature which is necessary to compare the two analyses, nor does she analyze the rising price of gas and its effect on consumption.

CUB also disagrees with AIU's position that there is no connection between the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA and the returns earned by investors. CUB submits the benefits of Rider VBA accrue directly to AIU's common equity shareholder as equity holders are exposed to more cash flow risk than debt holders because public utility debt holders are paid first out of a company's earnings, while any remaining earnings then accrue to shareholders through growth from retained earnings and cash flows from dividends. Because Rider VBA provides revenue stability, and will enable AIU to increase earnings in the future, the value of this stability accrues directly to equity shareholders, CUB submits this should be accounted for by reducing AIU's return on equity.

CUB notes that AIU has also proposed Rider QIP for its electric operations. CUB submits that should Rider QIP be adopted, AIU will face significantly reduced risk when investing capital in the plant accounts covered under Rider QIP because the rider guarantees cost recovery, which protects investors from the possibility that they will fail to recover their investment. CUB posits the Commission must properly account for this significantly reduced risk in setting AIU's cost of capital. CUB submits that if Rider QIP is approved, AIU should receive a cost of capital on any investment made under Rider QIP that is equivalent to each utility's embedded cost of long-term debt, which AIU has proposed is 6.668% for AmerenCILCO, 6.538% for AmerenCIPS, and 7.975% for AmerenIP. CUB submits this return will allow AIU access to the capital it needs to finance projects under QIP, while recognizing the dramatically reduced risk. CUB believes this recommendation to limit the cost of capital on Rider QIP investments is conservative and the Commission may find that other, additional measures are necessary.

d. IIEC's Position

IIEC notes that AIU is proposing riders that would effectively change the rates set in this proceeding to assure levels of revenues that fully recover, or IIEC suggests possibly exceed, its cost of service. IIEC claims the proposed riders can actually provide AIU with an opportunity to earn more than its authorized return on equity. IIEC submits that rate adjustments, pursuant to the proposed riders, are not based on consideration of all of AIU's revenues, expenses and invested capital, but on only selected elements. IIEC suggests that if the Commission approves the requested riders, then AIU's risk would be reduced, and a reduction to its authorized return on equity would be warranted.

IIEC avers that if either of the proposed Riders if approved, the risk of AIU not recovering its authorized targeted revenues would be shifted to customers (in the form of increased rate volatility), AIU would gain revenue stability, and the market would perceive AIU as a firm with reduced risk. IIEC notes the parties examining the cost of equity effect of the riders do not disagree that approval of one or both riders will have such an effect, however they do disagree on the magnitude of the necessary adjustment to their recommended costs of equity. Mr. Gorman recommends that AIU's

recommended return be decreased by an amount in the range of at least 0.5% with rider approval, which would make IIEC's recommended return on equity 9.5% in that event.

IIEC notes that AIU witness McShane acknowledges the risk reducing effect of Rider VBA, and by equating Rider VBA to unspecified weather normalization clauses previously examined by S&P, she concludes that her gas cost of equity recommendation should be adjusted by no more than the 10 basis points. IIEC avers that Ms. McShane is silent about Rider QIP's cost of equity effect, and it appears she believes no adjustment is necessary. IIEC submits she contends that Rider QIP is to the benefit of customers because the rider will result in ratepayers being spared the cost of proceedings to examine AIU's proposed infrastructure projects, while she makes no mention of what AIU gains from approval of the rider. IIEC argues that approval of Rider QIP would certainly benefit AIU and should be accompanied by a reduction in the approved return on equity.

While Staff witness Freetly agrees that AIU's risk will be reduced by Rider VBA, IIEC submits that her recommended 10 basis point reduction is inadequate. IIEC further notes that CUB witness Thomas also finds that Rider VBA will have risk reducing effects that warrants a reduction in the recommended authorized gas returns. IIEC avers that Mr. Thomas' analysis of Rider VBA's revenue and cost of equity impacts would have been had it been in place in the past, causes him to recommend a cost of equity reduction of 67.5 basis points. IIEC notes that he further recommends, if Rider QIP is approved, the Commission authorize a reduced return on Rider QIP electric projects.

IIEC submits that the Commission has before it a record that clearly establishes that approval of one or both of the requested riders will reduce AIU's risk. IIEC believes the principles underlying the Commission's consistent approach to determining the appropriate cost of equity for utilities require recognition of the change in the utility's risk that would accompany rider approval. IIEC avers that Section 9-201(c) of the Act requires that the Commission determine an appropriate cost of equity adjustment, since that is a necessary prerequisite for fulfilling the Commission's statutory obligation to determine just and reasonable rates on this record. Although no party may have suggested the perfect resolution in this case, IIEC submits that Mr. Gorman presents the most reasonable of the positions that accord with the reality of AIU's reduced risk under approved riders.

While AIU criticizes Mr. Gorman's recommendation that AIU's cost of equity be reduced by at least 50 basis points as speculative unsupported by analysis, IIEC submits that it is well-supported, and notes that in the recent Peoples case, the Commission approved just such a judgmental adjustment following approval of a similar rider. IIEC notes that AIU does not criticize Staff's 10 basis point proposed adjustment, although IIEC submits that Staff's analysis of risk reducing factors attributable to the rider was equally judgmental. IIEC avers that AIU suggests an adjustment similar to

Staff's, based on treating Rider VBA like a weather normalization adjustment, despite the rider's much broader coverage.

IIEC argues that AIU does not deny that Rider VBA will have an effect on its revenues, its risk, and on its cost of equity, but simply disagrees with IIEC and CUB on the magnitude of that effect. IIEC submits that the burden is on AIU to prove the reasonableness of its proposed rates, including the reasonableness of the elements that make up those rates, and where other parties have presented sufficient support for a risk adjustment, as here, the utility must rebut that evidence. IIEC avers that AIU has not done so, and the evidence shows that a 10 basis point adjustment is inadequate in this instance.

9. Commission Conclusion

As previously noted, AIU accepts Staff's recommended cost of equity for this proceeding. Staff, CUB, and IIEC each present their own cost of equity analyses. Staff witness Freely's recommendation is based on a discounted-cash flow analysis and CAPM analysis. CUB witness Thomas utilized a constant growth, annual DCF model to estimate AIU's cost of equity. IIEC witness Gorman used a multi-stage DCF model, RP model, and CAPM model.

The Commission notes that Staff has proposed two recommended cost of equity numbers for AIU, dependent on the Commission's decision on AmerenIP's auction rate bonds. As the Commission has earlier rejected AIU's position on the AmerenIP auction rate PCBs, it appears to the Commission that Staff's recommended cost of equity is 10.72% for AIU's natural gas distribution operations, and 10.68% for AIU's electric delivery service operations.

Before the Commission turns to the details of the parties return on equity estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. The Commission must balance two competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, neither does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary. The Commission recognizes that it must also consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While the Commission recognizes that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record, and consistent with previous Commission decisions, to the extent possible.

a. CAPM

First, the Commission will consider CUB witness Mr. Thomas' recommendation that the CAPM should not be used as a primary tool to estimate cost of equity, but

should only be used to check the reasonableness of the DCF model. He contends that CAPM has such bias in its calculations that it is unreasonable to rely on it to estimate cost of equity. The Commission notes it has considered this argument previously, including most recently the IAWC rate case, Docket No. 07-0507. As the Commission noted there, the only new information or argument presented by CUB appears to be the Nagel Paper, which is discussed in the parties' testimony and briefs.

Mr. Thomas argues that the version of CAPM used by the Commission was rejected in the Nagel Paper, as it had a higher forecast error than the more simplified version. While it appears to the Commission that in the Nagel Paper raw or unadjusted betas were used in CAPM, the Commission can find no suggestion, other than Mr. Thomas' testimony, that adjusted betas were excluded due to forecast error. There does not appear to be any support in the record for Mr. Thomas' assumption that a simplified version of CAPM, where all betas equal 1.0, would have a lower forecast error than the traditional CAPM with the use of adjusted betas. Based upon a review of the record, the Commission is inclined to agree with Staff that the Nagel Paper's finding that using a simplified CAPM where beta is set to 1.0 is superior to the use of unadjusted betas, which tends to support use of adjusted betas, rather than unadjusted betas. The Commission does not believe the record supports a finding that the Nagel Paper undermines the usefulness of CAPM in setting market required returns on equity in utility cases. It appears to the Commission that the Nagel Paper in fact supports the long-standing practice of the use of adjusted betas in CAPM rather than unadjusted betas.

Further regarding CAPM, Mr. Thomas urges the Commission to reject the analyses of Staff and IIEC, as both parties used adjusted betas in arriving at their results, and Mr. Thomas suggests that unadjusted betas are superior when calculating a utility's return on equity. The Commission has reviewed the testimony and arguments of the parties on this issue, and does not find CUB's arguments convincing. The Commission is of the opinion that the continued use of adjusted betas, when combined with appropriate proxy groups, is appropriate and should continue.

The next disputed issue relates to the calculation of EMRP used in the CAPM. Staff developed its EMRP using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium of 9.03%. Staff used as its risk-free rate the thirty-year U.S. Treasury Bond yield as of February 14, 2008 of 4.72%, while Staff's DCF estimate of the S&P 500 was 13.75% for the fourth quarter of 2007.

Mr. Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return

on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%. Both of his market risk premium estimates were derived based on historical returns on the S&P 500.

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB states the EMRP represented the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate, and should be the same for all markets and firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk. CUB suggests that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%, and CUB recommends using a value of 5.0%.

In the Commission's view, IIEC's first EMRP analysis, wherein inflation is added to the average market return and subtracted from projected Treasury bond yields, fails to consider that the real market risk premium is not stable over time, which seems almost a given, as IIEC averaged data from 1926 to 2006. A major shortcoming in IIEC's second analysis is that it relies largely on historical data. As in previous cases, the Commission finds such an approach unacceptable as an average of historical returns is not a reliable predictor of future returns.

CUB alleges that historical market risk premiums have been shown to be consistently too high. CUB suggests that the EMRP adopted for purposes of this proceeding should be based upon Mr. Thomas' review of opinions of members of the financial and academic arenas, which suggest that surveys of investors show a reasonable EMRP to be between 3.0% and 5.0%. The Commission notes that it previously rejected Mr. Thomas' proposed EMRP based on this same reasoning in the most recent IAWC rate case, Docket No. 07-0507. As the Commission indicated there, Mr. Thomas' suggestion does not seem to allow for the EMRP to change over time, which the Commission believes is necessary for any approach or method adopted. Additionally, the suggested EMRP's by the other parties call into question the validity of Mr. Thomas recommendation.

b. DCF

The Commission will next consider the various issues relating to the DCF model and the inputs thereto. Ms. Freely applied a multi-stage, non-constant growth quarterly DCF model. Mr. Gorman performed both constant growth and non-constant growth DCF models, however, he rejected the use of the constant growth model as its results were based on growth rates that were not sustainable. Mr. Thomas suggests a constant growth, annual DCF model be adopted. The Commission notes that Mr. Thomas has presented no new evidence in support of the annual DCF model. The Commission strongly believes that the quarterly DCF model should be utilized to

estimate the cost of common equity, as demonstrated by numerous previous Commission decisions. It is the Commission's opinion that the use of this model accurately recognizes the timing of cash flows to investors, which is necessary to estimate the investor required rate of return. Use of an annual DCF model, the Commission believes, would unnecessarily introduce measurement error and downward bias to the results.

The Commission notes that it has traditionally relied on a constant growth DCF model with analysts' estimates of EPS growth in developing the cost of common equity for utilities in rate cases. Staff suggests use of a multi-stage, non-constant growth, quarterly DCF model in this proceeding. IIEC suggests the use of a two-stage DCF model, while CUB suggests the use of the constant growth DCF model using historically derived internal growth rates rather than analysts' estimates. Staff and IIEC believe analyst growth rates are so high as to be not sustainable in the long run for use in a constant growth model, and therefore produce too high return on equity results. All parties used proxy groups of gas and electric companies for modeling purposes.

Ms. Freetly modeled three stages of dividend growth for use in her multi-stage, non-constant growth DCF model. For her first stage, she assumed a growth stage of five years. Her second stage is a transitional stage lasting from the fifth to the tenth year, while the third or "steady" stage growth rate begins after the tenth year. For the first stage, Ms. Freetly used the market-consensus expected growth rates from Zacks, for the third-stage she used the 20-year forward U.S. Treasury rate, and the middle stage was an average of the first two rates. The result of her DCF analysis was a suggested return on common equity of 9.41% for the gas sample, and 10.01% for the electric sample.

Mr. Gorman modeled a two-stage, non-constant growth DCF model, where the first stage relied on an average of the consensus of Zack's, Reuters, and SNL Financial to determine analysts expected growth rates for the first stage of the model. For the second stage of the model, from six years to perpetuity, he assumed each company's growth would converge on the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP. His two-stage non-constant DCF model resulted in a 9.6% suggested return on equity.

The Commission notes that it has rejected CUB's DCF model for its continued use of an annual model, rather than a quarterly model. CUB further suggests that the Commission consider historical internal growth rates, rather than analyst's estimates of future growth in the DCF model, arguing that analyst's estimates have been shown to be overly optimistic. The Commission is of the opinion that for DCF purposes, a forward-looking estimate of at least near term growth rates is appropriate, and will decline to adopt CUB's suggestion. CUB's approach has been routinely rejected by the Commission, including very recently in Docket No. 07-0507.

The Commission notes that Staff and IIEC are in agreement that at least in this instance, the use of a single-stage, constant growth DCF model is inappropriate, as

analyst's estimates for earnings growth are unreasonably high and are not sustainable for utilities. The Commission agrees with Staff and IIEC that the tradition constant growth model would in this instance, result in suggested growth rates that would exceed the growth rate for the U.S. economy in perpetuity, which appears unlikely. Both Staff and IIEC suggest in this instance, the use of a multi-stage model, with IIEC suggesting a two-stage model, while Staff suggests a three-stage model.

c. Risk Premium Model

Mr. Gorman has also presented the Commission with a risk premium analysis separate from his CAPM analysis. For this model, Mr. Gorman used two estimates of risk premium to develop a range to define the cost of equity. The first estimate was based on the difference between commission authorized returns on common equity, and Treasury bond yields. For the second estimate, Mr. Gorman calculated the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields.

Mr. Gorman's analyses resulted in a return on equity estimate in the range of 9.8% to 10.2%, with a mid-range estimate of 10.0%. It appears to the Commission that Mr. Gorman's risk premium model suffers from the same deficiency as the EMRP used in his CAPM analysis, as it relies on historical returns in an attempt to calculate a forward-looking number. As such, the Commission will decline to use Mr. Gorman's risk premium analysis in determining the authorized return on equity for AIU.

d. Adjustment for Reduced Risk of Gas Operations

While the Commission's complete analysis and decision on Rider VBA and Rider QIP can be found in later parts of this Order, the Commission notes that at this time, it is not authorizing the implementation of either Rider by AIU. The Commission does however, in the Rate Design section of this Order, make the decision to authorize recovery of more of AIU's fixed costs through the customer charge. The Commission is of the opinion that this move toward AIU recovering more fixed costs through the fixed monthly charge will have a similar effect as adopting Rider VBA, in that AIU will be more assured of recovering its fixed costs of service for gas operations. As a result, AIU will face less risk and an accompanying reduction in the authorized return on equity is warranted. Although none of the parties addressed this result directly, the discussions and analyses on the effects of Rider VBA and Rider QIP are helpful to the Commission in its consideration of the appropriate level of reduction in risk associated with increasing the fixed customer charge to account for a greater portion of fixed costs. While the Commission recognizes that this change lessens the risk for AIU to recover fixed gas charges, there is still some risk remaining that reduced natural gas consumption could result in an under-recovery situation. As such, the Commission deems it appropriate to adjust AIU's authorized return on equity for its gas operations downward by 10 basis points. The Commission is of the opinion this reduction adequately reflects the changes adopted in the rate design portion of this Order, and reflects that AIU's risk of not recovering its fixed costs will have been reduced.

e. Authorized Returns on Equity

Having addressed the significant contested issues that relate to cost of common equity, it appears to the Commission, as discussed above, that there are significant shortcomings with respect to the analysis of CUB witness Thomas. The Commission has indicated that it will again decline to adopt his suggestion to use an annual growth DCF mode that incorporates historically derived internal growth rates. Likewise, his suggestions concerning CAPM are rejected, along with his suggested EMRP. Likewise, Mr. Gorman's Risk Premium and CAPM analysis are rejected and will not be considered as they rely too heavily on historical returns in calculating a forward looking recommended return on equity.

The Commission finds value in both Staff's and IIEC's DCF analyses, along with Staff's CAPM analysis. Each has suggested the use of a multi-stage DCF model in this instance to mitigate the impact of unsustainable analyst estimates of growth, using instead estimated proxies of U.S. GDP growth as the long-term growth rate. Staff's DCF analysis, based on a three-stage model, results in a recommended return on equity of 9.41% for AIU's gas operations, and 10.01% for AIU's electric operations. IIEC's DCF analysis, using a two-stage approach, results in a recommended return on equity for both electric and gas operations of 9.6%. Staff's CAPM analysis resulted in a cost of equity recommendation of 12.04% for AIU's gas operations, and 11.94% for AIU's electric operations.

The Commission finds IIEC's DCF analysis, along with Staff's DCF and CAPM analyses, to be without material flaws, and should be considered in establishing AIU's cost of common equity. The Commission further notes that Staff proposes to adjust its recommended electric results downward by 30 basis points, as Staff determined that AIU was less risky than the electric proxy group. The Commission notes this adjustment appears uncontested and it will be adopted for calculating Staff's recommended return on equity.

Having reviewed the evidence and arguments, the Commission concludes that AIU's cost of common equity is 10.68% for gas operations and 10.65% for electric operations. These returns on common equity give equal weight to the results of Staff and IIEC DCF analyses, which is combined with Staff's CAPM analysis. As indicated above, the authorized return on equity for AIU's natural gas operations is adjusted downward by 10 basis points to reflect the change in Rate Design adopted in this Order.

	GAS		ELECTRIC	
<u>Party</u>	<u>DCF</u>	<u>CAPM</u>	<u>DCF</u>	<u>CAPM</u>
Staff	9.41%	12.04%	9.71%	11.64%
IIEC	9.60%		9.60%	
Average	9.51%	12.04%	9.65%	11.64%
Midpoint	10.78%		10.65%	
Risk Adjustment	(0.10)%			
AUTHORIZED RETURN ON EQUITY	10.68%		10.65%	

10. Commission Authorized Rates of Return on Rate Base

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.01% rate of return on net original cost rate base for electric operations; AmerenCIPS should be authorized to earn an 8.20% rate of return on net original cost rate base for electric operations; and AmerenIP should be authorized to earn an 8.68% rate of return on net original cost rate base for electric operations. The tables below show the development of that authorized rate of return:

Electric Operations AmerenCILCO

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.65%	4.95%
Total	467,617,514	100%		8.01%

AmerenCIPS

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.65%	5.10%
Total	1,057,618,734	100%		8.20%

AmerenIP

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.65%	5.51%
Total	2,079,219,209	100.00%		8.68%

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.03% rate of return on net original cost rate base for gas operations; AmerenCIPS should be authorized to earn an 8.22% rate of return on net original cost rate base for gas operations; and AmerenIP should be authorized to earn an 8.70% rate of return on net original cost rate base for gas operations. The tables below show the development of that authorized rate of return:

**Gas Operations
AmerenCILCO**

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.68%	4.97%
Total	467,617,514	100%		8.03%

AmerenCIPS

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.68%	5.12%
Total	1,057,618,734	100%		8.22%

AmerenIP

<u>Component</u>	<u>Amount</u>	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.68%	5.53%
Total	2,079,219,209	100.00%		8.70%

VII. PROPOSED RIDERS

Among the Proposed Tariffs filed by AIU are its proposals for several new revenue generating riders. Rider UBA-Uncollectibles Balancing Adjustment, Rider UBBA-Uncollectibles Balancing Base Rate Adjustment, and Rider UBPA-Uncollectibles Balancing Purchased Power Adjustment concern amounts billed to electric and gas customers that have not been paid. Although it continues to believe that the manner in which it recovers uncollectibles warrants further consideration, in his rebuttal testimony, AIU witness Nelson indicated that AIU is withdrawing its request for approval of these three riders concerning uncollectibles. (See Ameren Ex. 18.0 at 5) Other proposed riders that AIU still supports are Rider VBA-Volume Balancing Adjustment ("Rider VBA"), applicable to residential and small commercial gas delivery service customers, and Rider QIP-Qualifying Infrastructure Plant Surcharge ("Rider QIP"), applicable to electric delivery service customers. Rider VBA and Rider QIP will be considered separately below.

A. Rider VBA**1. AIU's Position**

The two components of AIU's gas cost of service are gas supply and gas delivery. The cost of the natural gas supply itself is recovered through the PGA rider. About 97% of gas delivery cost is recovered through tariff base rates primarily consisting of customer charges, volumetric delivery charges, and, for certain larger customer groups, demand charges. The remaining portion (about 3%) of delivery service cost is recovered through "other" tariff charges (e.g., late pay charges, insufficient fund charges, disconnect/reconnect fees, etc.). Of the fixed delivery service cost recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service cost recovery comes from the monthly customer charge.

Because a significant portion of its fixed costs are recovered through the volatile volumetric component, AIU observes that it could significantly over- or under-recover

the cost of service from year to year due to fluctuations in usage. AIU indicates that such fluctuation has occurred, but that it has been decidedly one-sided. AIU reports that the level of sales it has experienced has been consistently lower than that assumed in the test year, even in the very first year after a rate order. According to AIU, this has caused it to under-recover its cost of service, and thus it has not earned the authorized rate of return.

The three principal factors that AIU identifies as being responsible for sales differing from forecasted levels are (1) weather, (2) a general decline in natural gas usage, and (3) targeted gas energy efficiency measures. With regard to weather, when recovering fixed costs through volumetric rates, smaller customers are apt to pay more toward fixed costs in colder weather when they use more gas for heating and pay less toward fixed costs in warmer weather when they do not use as much gas for heating. Gas usage is also generally declining across the industry according to AIU, so any efforts to recover fixed delivery costs through a volumetric rate will likely suffer over time. AIU attributes at least some of the general decline to gas appliances becoming more efficient and there being no significant new domestic uses for gas. Despite this explanation for the decline in gas usage, Mr. Nelson indicates that AIU has not yet experienced much of an impact from the third factor.

AIU also points out that volumetric delivery rates pose a problem in regard to energy efficiency initiatives. When utility revenue is tied to the volume of gas sold, AIU observes that the utility has no incentive to encourage conservation and the efficient use of gas. If this disincentive is removed, AIU witness Hanser indicates that AIU is willing to participate in a collaborative stakeholder process to identify specific energy efficiency measures to be implemented and the amount to be expended on each.⁹

AIU seeks to remove this disincentive by "decoupling" the recovery of fixed delivery service costs from the amount of gas sold through its proposed Rider VBA. Generally, under a decoupling rider, on a periodic basis revenues are "tied-up" to the predetermined revenue requirement using an automatic rate adjustment. The result is that the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales. Citing research conducted by the National Association of Regulatory Commissioners ("NARUC"), AIU relates that ten other states have approved decoupling and three states and the District of Columbia are investigating decoupling. AIU adds that 13 of the 14 states mentioned also have energy efficiency programs. AIU adds that energy efficiency programs conducted in conjunction with a decoupling rider provide societal and economic benefits, which ultimately benefit customers.

If the Commission is inclined to approve Rider VBA, AIU states that Rider VBA is designed to operate in the same manner as the Peoples/North Shore decoupling rider

⁹ AIU filed with the Commission proposed gas efficiency measures resulting from the collaborative effort, initiating Docket No. 08-0104. The gas efficiency filing identifies the definitive programs, the associated cost of the programs, and a proposed rider for recovery of the costs. Docket No. 08-0104 is currently on-going.

approved by the Commission as a four-year pilot program in consolidated Dockets Nos. 07-0241 and 07-0242 on February 5, 2008. Rider VBA would adjust customer rates each month based on changes in per customer usage for the residential (GDS-1) and small commercial (GDS-2) customer classes based on an AIU-configured usage-per-customer benchmark. A monthly surcharge would be imposed if per-customer usage in the rate classes falls below a baseline set in this proceeding (regardless of the reason for the decline), without examining whether overall revenues have increased. AIU has agreed to implement Rider VBA in the context of a pilot program that would terminate on December 31, 2012. AIU is also willing to provide the Commission with an annual report of the rate of return of AmerenCILCO, AmerenCIPS, and AmerenIP and the effect on that return of Rider VBA. AIU further agrees that the Rider VBA formula should be designed to recover only the utility's fixed costs that are reflected in the revenue requirement recovered via the volumetric delivery charge.

These commitments, AIU argues, sufficiently counter the concerns of AG/CUB witness Brosch that the Commission will inadvertently allow unreasonable earnings when it evaluates rider recovery of costs on an annual basis. To the extent that the rate of return reports are not sufficient, AIU states that the Commission can request further information, which AIU has a duty to respond to pursuant to Section 5-101 of the Act. The "pilot" nature of Rider VBA should also help to resolve the concerns of Mr. Brosch because if renewal of the rider is desired, changes can be made based upon what stakeholders have learned from the pilot program

AIU also responds to Mr. Brosch's assertion that Rider VBA is asymmetrical, in that it only benefits AIU. AIU insists that Rider VBA is plainly symmetrical, meaning that if a colder than normal winter were to occur customers would receive credits for the higher than anticipated consumption and vice versa. AIU witness Cooper even testifies that had Rider VBA been in place this past winter, customers would have received credits in three of the four winter months. AIU contends that Rider VBA will simply track the volumetric cost collection per customer and true-up to prevent either the under- or over-recovery of Commission approved fixed costs for test year customer levels. Moreover, setting aside the question of symmetry for a moment, AIU notes that Mr. Brosch does not address the central issue: that given today's contemporary fossil fuel issues, establishing rates that give utilities an incentive to sell more natural gas is a policy that no longer makes sense.

AIU further contends that the AG's legal arguments against Rider VBA are misplaced. Citing Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 123-9 (1995), AIU asserts that the Commission has discretion to allow rider recovery in a proper case and the legal authorization to approve riders will not be reversed absent an abuse of discretion. Under City of Chicago v. Illinois Commerce Commission, 218 Ill.App.3d 617, 628 (1st Dist. 1996), AIU also states that rider recovery is not limited only to circumstances where unexpected, volatile, and fluctuating costs are present.

In response to Staff witness Ebrey, AIU denies that Rider VBA represents only "partial" decoupling since it would not reflect changes in the number of gas customers. In contrast to Ms. Ebrey's proposal and commentary, AIU states that it is not seeking to isolate its revenue from ~~—all~~ "changes" that may occur in the course of the operation of its gas utility businesses. Rather, AIU indicates that it is seeking to decouple Commission approved rate recovery for test year customer levels from changes in volumetric consumption, specifically due to declining usage trends and weather patterns. AIU characterizes Rider VBA as "plain vanilla" decoupling, and asserts that it is not intended to operate differently from what was granted in Docket Nos. 07-0241 and 07-0242 (Cons.). AIU insists that Rider VBA is ~~—all~~ "full decoupling" since the volumetric component of its rates are to be trued-up on a margin per customer basis to insure each customer pays his/her share of fixed costs.

If actual (i.e., post test year) customer count data is incorporated, AIU maintains that Rider VBA no longer remains a rate design vehicle designed to recover Commission approved revenue requirements for test year customer levels. Rather, it becomes a broader formulaic rate that essentially will function to alter the revenue requirement equation established by the Commission in this docket on an annual basis. Additionally, AIU contends that Ms. Ebrey's method would do so asymmetrically because her recommendation has not articulated any mechanism by which AIU would be permitted to include costs associated with changes in the number of customers, or by which AIU would be permitted to prove up the value of the plant assets necessary to meet customer growth. Such a situation, AIU argues, essentially amounts to single-issue ratemaking.

Under Ms. Ebrey's proposal, AIU claims that the lack of symmetry would be so prejudicial to its interests, that it would be confiscatory. Essentially, AIU continues, Ms. Ebrey's proposal would function to annually reduce AIU rates by spreading the revenue requirement across a broadening customer base as new customers are added while it completely ignores costs associated with such load growth. Thus, AIU contends that it is inevitable that a changing or increasing cost of service due to plant and expenses associated with new customers with unchanging revenue would not afford AIU a reasonable opportunity to earn the rate of return approved by the Commission herein.

Conversely, AIU points out that it is not explained how customers would be impacted by the potential of an automatic rate increase if customer numbers were to contract in a given year. It is not clear how such a situation would fit within the constructs of the Act. While it is uncommon for customer count reductions to occur, AIU contends that demographic shifts such as population decline in certain areas, or sudden and dramatic increases in natural gas cost can result in customer count reductions. Without any consideration in the record of such issues, AIU urges the Commission to decline to add customer count variables to the Rider VBA formula.

With respect to Staff's assertion that it would be illogical to have identical decoupling pilot programs for both AIU and Peoples/North Shore, AIU believes otherwise. AIU contends that having multiple gas utilities in Illinois with the same pilot

program insures that the results of the pilot program are not skewed by some operational condition a single utility. Under its proposal, AIU states that the Commission will have a diversity of data to analyze.

An alternative to Rider VBA that would still promote full fixed cost recovery by the utility is recovery of all fixed delivery costs through a fixed monthly charge to all affected customers. Under such a rate design, AIU states that utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. AIU indicates that it can either implement the fixed monthly charge concept as described above, or implement Rider VBA which would continue to retain a volumetric rate design component and, also, ensure a precise match between actual revenue and those previously approved by the Commission. Another alternative, AIU continues, would be to adjust the test year billing determinants for a downward trend in sales due to efficiency gains, but this is the less preferable option because it involves guesswork, whereas the fixed charge option does not.

2. Staff's Position

Staff has not made policy or rate design recommendations regarding whether Rider VBA should be approved in these proceedings. Staff has, however, proposed a number of modifications to the rider in the event the Commission decides to approve decoupling for AIU. First, Staff recommends that the Commission incorporate the additional safeguards it approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff notes that AIU has agreed to modify Rider VBA to reflect any differences between the Rider VBA as filed in these proceedings and the Rider VBA approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff does not take issue with the slight revisions to the proposed language addressing an annual internal audit of Rider VBA proposed by AIU.

Staff's second proposed modification involves a discussion of "full" versus "partial" decoupling. Staff witness Ebrey proposes that ~~full~~ decoupling" be approved as a pilot program in this proceeding (if Rider VBA is to be approved) rather than the same program design that is already in pilot status for North Shore and Peoples, which is ~~partial~~ decoupling." She states that ~~full~~ decoupling," as described in the NARUC document titled, ~~Decoupling~~ For Electric & Gas Utilities: Frequently Asked Questions (FAQ)", provided by AIU in response to AG data request 3.03d Attach (Staff Group Ex. 1), adjusts utility revenues for any deviation between expected and actual sales regardless of the reason for the deviation. Thus, Ms. Ebrey continues, it ~~decouples~~" revenues from any and all variations between actual operations and those predicted by the revenue requirement. Staff asserts that the variation of the full sales decoupling proposed by AIU is called ~~Sales~~-Margin Decoupling," which separates margin recovery from sales by setting a margin-per-customer target. (Id.) Since the proposed AIU and approved North Shore and Peoples decoupling riders are both based on the same "partial" decoupling, Staff avers that it would not be logical to approve for AIU a program design identical to the one approved for North Shore and Peoples as a pilot program. The result would be three identical pilot programs; nothing would be gained from such

an exercise. According to Staff, however, a Rider VBA program based on ~~full~~ decoupling as Staff proposes as a pilot program for AIU would provide the Commission with another alternative for comparison at the end of the pilot periods to determine which form of decoupling is preferable for Illinois utilities.

The third modification proposed by Staff concerns the adjustment calculation in Rider VBA to reflect ~~full~~ decoupling, should the Commission decide to approve the rider. Staff understands that the intent of Rider VBA is to assure dollar-for-dollar recovery of the portion of fixed costs currently recovered through the volumetric portion of delivery service charges. The proposed rider has an annual reconciliation mechanism which AIU says will only allow it to recover the Commission approved revenue requirements and not a dollar more. Staff, however, is not sure that the reconciliation mechanism can be relied upon to limit recovery to the approved revenue requirements.

In discussing its concern, Staff explains that Rider VBA has two main formulas: one to determine the Effective Component which calculates the Rider VBA charge to be applied to the Effective Month, and the other to determine the Reconciliation Adjustment for the annual true-up. The Effective Component formula calculates any over or under recovery of the fixed cost portion of the volumetric charges on a per customer basis as opposed to a total revenue requirement basis. Since any Commission-approved revenue requirement is based upon a projected number of customers, if AIU's actual number of customers exceeds that projected level, Staff indicates that there appears to be a possibility that AIU could collect more fixed costs through Rider VBA than approved in the revenue requirement. Specifically, AIU would collect more fixed costs from the additional customers' volumetric charges and from their monthly customer charges. Staff states that this would not be a concern if there were specific provisions in the proposed rider that would address this issue; however, there are none. Staff offers an example in its Initial Brief setting forth its concern. (Staff Initial Brief at 253)

Staff further explains that in approving the decoupling rider for North Shore and Peoples, it was implied that fixed costs are costs that are necessary to operate the utility regardless of any changes to the operation--a ~~fixed~~ cost of doing business regardless of the amount of business conducted. Converting the fixed costs to be recovered to a per customer basis suggests to Staff, however, that the costs are not truly fixed but that they will vary with the number of customers served. Staff contends that additional customers over the level assumed in the revenue requirement would not necessarily result in additional fixed costs to AIU. AIU claims that the ~~overwhelming majority~~ of its delivery system revenue requirements do not ~~vary~~ with the volume of natural gas consumed by customers and is thus ~~fixed~~ in nature. (AIU response to Staff data request TEE 15.05) In furtherance of this claim, AIU states that the only variable costs that the gas utilities have that are not recovered through the PGA clauses relate to odorant expense. (AIU response to Staff data request TEE 15.08) Staff points out, however, that AIU also claims, ~~Such~~ statement is not intended to mean that [AIU] cost of service or revenue requirements are 'fixed' for any period of time." (AIU response to Staff data request TEE 15.05) If costs vary based on any changes to the operations,

including changes in the number of customers served, Staff believes that they can not be truly fixed costs. Staff contends that AIU has had the opportunity to provide support for how it defines “fixed” costs, clarify its statement that the costs under consideration are not fixed for any period of time, identify the total dollar amount of fixed costs it is seeking to recover in its proposed revenue requirement, and separately identify the portions of those fixed costs of service that it is seeking to recover from the customer charge and from the volumetric usage charge. Staff asserts that no such support has been provided in the record.

Implementation of Staff’s third proposed revision to Rider VBA would first require AIU to identify those costs that are truly fixed. Modifying the Effective Component formula in the rider such that it is not calculated on a per customer basis but based on the total fixed cost component of the approved revenue requirement would follow. Specifically, Staff recommends that if the Commission approves Rider VBA that it modify the Effective Component formula as follows:

1. Effective Component

The adjustment, determined for each Rate, to be billed for the Effective Month is represented by the following formula:

$$[(RCBR / RCG) - (ABRR / AG)] \times RCG / T \times 100$$

Where:

RCBR represents the Rate Case Base Rate Revenue for the Reconciliation Month.

~~RCG represents the number of Rate Case Customers for the Reconciliation Month.~~

ABRR represents the Actual Base Rate Revenue for the Reconciliation Month.

~~AG represents the number of Actual Customers for the Reconciliation Month.~~

T represents the forecast Factor T for the Effective Month.

3. AG's Position

The AG argues that Rider VBA violates several critical ratemaking precepts and should be rejected. Setting aside the many legal infirmities of the proposed rider, the AG also argues that the evidence in no way demonstrates that a need for Rider VBA exists. Rider VBA, the AG asserts, would trigger piecemeal rate adjustments for

isolated elements of utility revenue requirements in the absence of compelling evidence that such piecemeal rate adjustments are warranted.

A review of the AG's position begins with its observation that both the Act and Illinois court rulings regarding the utility ratemaking process provide an essential regulatory and legal framework for the Commission's analysis of Rider VBA. When the Commission enters upon a hearing to review a utility's proposed rate increase pursuant to Section 9-201 of the Act, it must determine whether the proposed rates are just and reasonable and do so within the regulatory parameters which prohibit retroactive and single-issue ratemaking. (See BPI II, 146 Ill.2d at 195) Following the discussion of the AG's legal analysis is a review of its policy arguments.

a. Legal Considerations

The AG raises several legal arguments against Rider VBA. The first argument concerns single-issue ratemaking. For utility ratemaking purposes, the AG states that riders are closely scrutinized because of the danger of single-issue ratemaking. (See City of Chicago v. Illinois Commerce Commission, 281 Ill.App.3d 617 (1st Dist. 1996)) The rule against single-issue ratemaking is a ratemaking principle which recognizes that the revenue requirement formula is designed to determine a utility's revenue requirement based on the utility's aggregate costs and demand. The rule prohibits the Commission from considering changes to components of the revenue requirement in isolation. As noted by the AG, limited exceptions to the rule against single-issue ratemaking exist. Based on the case law and statutory authorizations issued to date, the AG recounts that Commission decisions implementing riders for the recovery of certain expenses have not been reversed by Illinois courts as illegal single-issue ratemaking when the expenses at issue are (1) unexpected, volatile, or fluctuating, (2) imposed on the utility by law, including federal and state law (such as environmental clean-up expenses) and municipal ordinance for a unique purpose (such as franchise fees), or (3) specifically authorized by statute. The AG avers that fluctuations in gas usage within a customer class do not fall within one of these categories. In contrast, the AG believes that a rider focusing solely on such fluctuations without regard for all other circumstances is a prime example of single-issue ratemaking.

The AG's second legal argument is that Rider VBA contradicts ratemaking principles established by the U.S. Supreme Court. In the case Bluefield, the Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. In spelling out the factors to be examined by regulators when establishing a utility's rate of return, the high court held that a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. (Bluefield, 262 U.S. at 692-693) The Court

specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (Id. at 693) The Supreme Court also recognized that changes in the marketplace may impact a utility's financial health and the appropriateness of the rates being charged, when it held that a rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. (Id. at 692)

The AG observes that the U.S. Supreme Court elaborated on the principles governing rate of return regulation in the case of Hope. In Hope, the Supreme Court held that investors have a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. But in Market St. Ry. Co. v. Railroad Commission, 324 U.S. 548 (1945), the AG reports that the Court specifically rejected the notion that a monopoly must be protected from market realities, such as competition or the effects of price on a consumer's demand and use of the service. The Court explained, —~~Even~~ monopolies must sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use." (Id. at 568)

Illinois courts have adopted the Bluefield and Hope standards and applied them to the regulation of utilities in Illinois. (See Illinois Bell Telephone Co. v. Illinois Commerce Commission, (1953), 414 Ill. 275) Moreover, the AG adds, Illinois appellate courts have declared that it is the ratepayers' interest which must come first:

The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail. (Camelot Utilities, Inc. v. Illinois Commerce Commission, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), See also Citizens Utility Board v. Illinois Commerce Commission, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995))

These and the previously discussed holdings suggest, according to the AG, that AIU's request for the guaranteed recovery of the approved per customer —~~margin~~ revenue" stream established when rates are set in this case through Rider VBA has no support in the utility regulatory law that has guided this Commission's establishment of rates.

The third legal argument made by the AG is that the circumstances at hand do not warrant the extraordinary regulatory treatment of a rider. In the case of A. Finkl & Sons Company v. Illinois Commerce Commission, 250 Ill.App.3d 317, 620 N.E.2d 1141 (1st Dist. 1993) (~~Finkl~~), the Illinois Appellate Court held that riders are useful in

alleviating the burden imposed upon a utility in meeting *unexpected, volatile, or fluctuating* expenses. (*Id.* at 327) (emphasis in original) In addition, the AG observes that the court noted that the amount of costs to be recovered through the rider at issue in the case was not significant, and were recoverable through the usual rate case mechanism. The criteria enunciated in Finkl for determining whether a utility expense should be recovered through a rider was affirmed by the Illinois Supreme Court in Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 651 N.E.2d 1089 (1995). While the Court upheld the Commission's approval of rider recovery of coal tar clean-up expenses in the case, it affirmed the criteria relied upon in Finkl for rider recovery of expenses, noting that the coal tar remediation expenses commonly incurred to comply with the mandate of federal and state law are sufficiently volatile and not within management's control to justify rider recovery.

In applying the Finkl standard to AIU's declining revenue situation, the AG examined the impact of Rider VBA had it been in place beginning in 2002. The AG reports that the largest annual margin dollar change would have been a margin revenue increase of \$18.6 million in 2006. Although this amount is not insignificant, the AG asserts that it is not particularly large in relation to the total test year operating income of \$272 million proposed by AIU in this proceeding. The AG does not consider this amount large enough to warrant rider treatment under Finkl. Nor does the AG believe that historical fluctuations in gas usage due to weather count as unacceptable levels of volatility under Finkl. The AG also suggests that AIU management has some control over usage in light of AIU witness Nelson's comments regarding energy efficiency programs.

The fourth legal argument raised by the AG concerns the Act's requirement in Sections 1-102 and 8-401 that utility rates be least-cost. The AG contends that implementation of Rider VBA will permit piecemeal rate increases that violate this requirement. Had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional \$38.8 million in gas delivery charges. If AIU's predictions about declining gas usage per customer are correct, the AG states that Rider VBA's monthly adjustment of customer rates will not produce rates that are ~~least-cost~~, as required by the Act.

The AG's fifth argument is that Finkl prohibits recovery of revenues lost due to energy efficiency and conservation efforts. In Finkl, the AG reports that the appellate court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or demand side management programs. Given the parallels between the rider at issue in Finkl and Rider VBA, the AG contends that implementation of Rider VBA would be illegal.

The sixth legal argument is that Rider VBA violates the Act's prohibition against discrimination in rates. Section 9-241 of the Act prohibits any utility from establishing or maintaining any unreasonable difference in rates or other charges between customer classes. AIU seeks to maintain a designated level of revenues per customer on a monthly basis after rates are set in this proceeding for residential and small commercial

classes, but not for the other rate classes served by AIU. Although AIU argues that a decoupling rider is needed because declines in usage per customer cause a significant under recovery in the fixed cost of service and an inability to earn authorized returns, the AG asserts that nowhere in any AIU witness' testimony does there exist evidence that decreases in usage per customer are limited to residential and small commercial customers. Nevertheless, Rider VBA does not apply to other customer classes. Therefore, according to the AG, Rider VBA constitutes unreasonable discrimination against residential and small commercial customers. The AG avers that adjusting the monthly charges to these customer classes, based on changes in future gas usage (and the margin revenues produced), from the baseline level of revenues per customer established in this case, but not for AIU's other customer classes, contradicts the prohibition in Section 9-241 against unreasonable discrimination between customer classes.

b. Policy Considerations

A part of any rate case, the AG relays, is the “~~rat~~atching principle,” which recognizes the importance of matching within the test year all revenues and costs (expenses, rate base, rate of return) to determine needed changes in utility service pricing. As long as revenues and costs remain in approximate balance, causing a utility's earnings to stay within acceptable proximity to authorized return levels, the utility may be able to go many years between rate cases. The fundamental problem with riders, the AG argues, is the potentially serious distortion of the matching principle under traditional ratemaking that occurs when a single expense item is tracked in isolation, thereby ignoring other changes occurring to expenses and revenues that affect a utility's revenue requirement.

A related concern of the AG is that implementation of any rider focusing on a single expense item will eliminate or reduce the incentive for utility management to control and reduce costs. Because rates are typically fixed for a period of years, the AG asserts that the regulatory lag that occurs provides utility management with efficiency incentives and symmetrical risks and opportunities for both ratepayers and shareholders -- depending on cost and revenue trends -- between rate cases. The AG notes that regulatory lag has worked out well for AmerenCILCO's gas operations, which AIU admits is currently over earning. Another advantage of traditional test year ratemaking over riders identified by the AG is the intensive focus upon utility operations and costs that occurs in a rate case in which Staff and other interested parties can carefully examine the components making up the revenue requirement.

In addition to the reduction in management incentives (resulting from eliminating regulatory lag), AG/CUB witness Brosch identifies other concerns stemming from rider recovery of certain rate elements:

- Shifting of cost responsibility and risk to customers who are least able to influence cost levels or sales levels;

- Increases in tariff and bill complexity that may be difficult to explain to customers or that may complicate customers' ability to control their costs;
- Administrative complexity and additional costs associated with audit verification and administration of complex accounting entries, cost allocations and/or tariff calculations, often on an accelerated procedural schedule; and
- Potential for inadequate regulatory oversight and auditing of rider tariffs.

Given the importance of the matching principle in traditional ratemaking and the potential problems inherent in rider recovery of rate elements, the AG contends that exceptions to normal test year ratemaking should only be allowed when extraordinary circumstances exist that preclude the setting of just and reasonable rates through the traditional test year process. The AG maintains that there has been no showing by AIU of any extraordinary circumstances sufficient to justify departing from the continued balanced regulation of future changes in AIU's costs and revenues via periodic rate cases.

Mr. Brosch testifies that costs or revenue changes to be tracked through a rider should generally have *all* of the following characteristics to merit the exceptional and preferential treatment inherent in riders:

- Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
- Beyond the control of management, where utility management has little influence over experienced revenue or cost levels;
- Volatile in amount, causing significant swings in income and cash flows if not tracked;
- Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews; and
- Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.

The AG asserts that it is no coincidence that the general criteria for rider treatment that are cited and discussed by Mr. Brosch are closely aligned with the factors considered and adopted in the Commission and Illinois court cases cited above. The AG maintains that AIU has failed to make a case that extraordinary rider treatment of revenues lost due to declines in usage per customer is needed from a financial perspective in order for AIU to have a reasonable opportunity to achieve a fair return on investment.

The arguments that AIU has made in support of Rider VBA are meaningless red herrings in the AG's view. In response to AIU's claim that full recovery of fixed costs is at risk because a portion is based on volumetric charges, the AG counters that AIU fails to acknowledge that the Commission sets rates after considering normal weather and the estimated number of bills that a utility expects to issue. Focusing on margin revenues per customer, the AG continues, also ignores the fact that AIU's revenue streams and expenses are dynamic. For instance, revenue from new customers may

compensate for existing customers' decreased usage. Improvements in productivity can also reduce expenses to compensate for existing customers' decreased usage.

The AG states further that under AIU's ratemaking paradigm a natural gas delivery utility should be made whole for all per customer load losses, no matter whether the decline in usage is due to conservation efforts, customers' desire to dial down the thermostat and reduce winter heating bills in response to high gas prices, or the prevalence and installation of more efficient appliances. Moreover, according to the AG, AIU witness Cooper confirmed that as customers increase their efforts to conserve natural gas, their delivery service rates will increase. (Tr. at 539-540) The AG is troubled that the amount of natural gas service used by a customer becomes irrelevant to the amount of money owed to the utility for gas delivery service. When usage per customer declines, AIU generally and theoretically asserts that its overall revenues and profits decline and its cost of service is not fully recovered. Even when revenues collected from new customers offset the impact of reduced usage by existing customers so that there is no loss in overall revenues, the AG understands that a surcharge may nonetheless be imposed on residential and small commercial customer bills under Rider VBA. Similarly, the AG also understands that even if total revenues exceed the level approved in this rate case, a surcharge will be imposed if use per customer declines.

Conspicuously absent from the record, the AG avers, is any evidence that overall margin revenues have dropped precipitously or become unstable in the years since AIU's last gas rate case so as to justify the unorthodox ratemaking treatment that Rider VBA brings. Moreover, the AG states that AIU provided no attrition studies or estimates of any kind showing margin revenue losses that will occur in the future that suggest that it will be unable to earn its authorized return after the entry of the rate orders in this proceeding or that justify the approval of Rider VBA. In fact, the AG points out, gas usage per customer has been declining for decades, yet AIU has been able to operate under the traditional rate making approach without decoupling. Rejecting Rider VBA will not harm AIU, the AG observes, because when under-recovery does occur the traditional rate case filing process is still available to AIU. Additionally, as noted above, had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional \$38.8 million in gas delivery charges--a cumulative impact of about 7.1% of overall margin revenues in those years. The AG asserts that this would have been an unjust windfall to AIU since the traditional rate case process would have protected AIU's interests.

The AG does not accept AIU's argument that Rider VBA is necessary to remove any disincentive to promote energy efficiency. First, the AG points out that AIU has no history of providing energy efficiency programs or assessing their effect on customer usage. Given this lack of experience, the AG claims that the discussion regarding the alleged disincentive to promote efficiency rings hollow. Second, the AG notes that AIU has no plans for energy efficiency programs beyond the \$6.5 million program at issue in Docket No. 08-0104. While AIU asserts that implementation of that program is contingent upon approval of Rider VBA, the AG observes that AIU witness Nelson acknowledges that the Commission can direct AIU to provide the program without Rider

VBA. Third, the AG maintains that Rider VBA may actually discourage customers from increasing the efficiency of their home or business or otherwise reduce their gas usage if their total bill is less dependent on the amount of gas they use. The AG finds AIU's concerns about promoting efficiency particularly specious when one considers that AIU is only seeking decoupling for its gas operations. As Mr. Nelson explains in his response to AG 3.03(c) (MLB), "average electric sales per customer are not declining. Implementing a decoupling mechanism for the electricity business likely would have the effect of providing [AIU] with less revenue over time, and would hasten the need for a subsequent rate case--neither of which is in the interests of [AIU] or its customers." (AG Initial Brief at 43) Thus, the AG concludes that AIU is apparently proposing only gas decoupling in furtherance of the simple financial goal of collecting the maximum revenue between rate cases for the benefit of shareholders--and not due to any altruistic motivation to remove disincentives to promoting energy efficiency.

The AG is also concerned by the additional administrative burdens that approval of Rider VBA will bring. According to the AG, Mr. Brosch and Staff witness Lazare both express concerns about the additional burden that review of three additional riders, and the three annual rates of return reports, will impose on all parties. The AG is not persuaded by AIU's assurances that Rider VBA reconciliations will be simple and uncontroversial.

4. CUB's Position

CUB objects to Rider VBA and relies on Bluefield, Hope, and Finkl in the same manner as the AG. CUB also discusses the arguments of Mr. Brosch. CUB spent additional time, however, discussing BPI II. In BPI II, the Illinois Supreme Court described the rule against single-issue ratemaking as recognizing that the revenue formula is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. To demonstrate this point, CUB states that an increase in depreciation expense attributable to a new plant may be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (CUB explains that demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt-hour ("kWh") rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, CUB states that the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses. (See BPI II, 146 Ill. 2d at 244-45) The exception permitting recovery of costs outside of the traditional rate-setting process is recovery through riders.

Riders allow a utility to collect revenues associated with a particular cost as it is incurred, without waiting until it files a general rate case to recover such expenses. CUB quickly points out, however, that rider cost recovery is only permitted under limited circumstances, as discussed in Finkl. In this instance, CUB does not believe that it is appropriate to make up for declining revenues, due to decreased gas usage, through a rider. CUB maintains that the proposed Rider VBA is beset by many problems. First, CUB is not convinced that Rider VBA is necessary and notes that AmerenCILCO's gas operation is over-earning despite declining gas usage by customers. CUB adds that fluctuation in earning is common between rate cases and that regulatory lag can even work to a utility's advantage, as it is currently for AmerenCILCO. When earnings are consistently low, CUB asserts that the proper course of action is to file for a rate increase.

CUB is also troubled by AIU witness Cooper's assertion that, rather than reviewing its proposed rates under the standards articulated in Article IX of the Act regarding just and reasonable rates, the Commission should consider that —~~the~~ real metric for determining whether the tariffs for a utility are just and reasonable is a comparison between the margin revenues generated by these tariffs versus the margin revenue requirement necessary for the utility to have a reasonable opportunity to earn its Commission authorized rate of return.” (Ameren Ex. 25.0 at 7) He further argues that the current rate structure has not resulted in earning the respective authorized rates of return. CUB contends that this argument invents a new standard of review — the —margin revenue requirement” — that belies the Act and well-established regulatory policies and principles. CUB believes that it is important to note that, while the Commission always establishes a revenue requirement level, it measures a utility's performance by whether it is meeting its approved rate of return. In fact, CUB continues, the Commission up to this point has never approved a specific level of margin revenues or margin revenue requirement for any gas utility in Illinois.

CUB takes no solace in AIU's willingness to modify Rider VBA so that it more closely resembles the Rider VBA approved in the Docket Nos. 07-0241 and 07-0242 (Cons.). First, CUB argues that calling the rider a "pilot," while simultaneously subjecting all residential customers to potentially higher delivery rates for four years, without substantial review of the program, does nothing to improve it. Second, Mr. Brosch testifies that the annual rate of return filings are no substitute for a correctly structured formula that accounts for all related costs and revenue changes between test years, and are virtually useless in determining whether the riders have caused AIU to earn returns in excess of those authorized by the Commission. Third, since a majority of the delivery system costs are fixed, CUB states that ensuring that only the utility's fixed costs are reflected in the volumetric delivery charge and the associated Rider VBA surcharge will have little to no effect on the level of surcharges imposed under Rider VBA.¹⁰

¹⁰ The Commission does not mean to slight CUB or diminish the worth of CUB's arguments by not addressing all of CUB's arguments in the Commission's review of CUB's position. Rather, given the similarities between CUB's position and the AG's position, the Commission simply does not believe that repetition of such similar arguments in the Order is warranted.

If it were the Commission's goal to provide utilities with guaranteed cost recovery of its fixed costs, CUB asserts that that policy would more appropriately dictate establishing recovery of all fixed delivery costs through the application of a fixed monthly charge to all affected customers. While CUB acknowledges AIU's suggestion that increasing the monthly customer charge is an alternative to its decoupling proposal, CUB opines that AIU is not seriously proposing to increase the monthly charge. If in fact that is what AIU is proposing, CUB contends that it would likely be rejected outright by this Commission as violating basic ratemaking principles like avoidance of rate shock, maintaining fair and equitable rates, and other cost of service principles. According to CUB, Dr. James Bonbright, an authority on utility ratemaking, has called into the question the propriety of uniform customer charges. CUB quotes Dr. Bonbright as saying, —uniformity of charge per customer (say, \$10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to recognize either cost differences or value-of-service differences between large and small customers." James C. Bonbright et al., "Principles of Public Utility Rates," at 397 (1988).

5. IIEC's Position

From IIEC's perspective, and from a general customer perspective, riders are objectionable and should not be approved when the riders: (a) inappropriately shift operating risk from the utility to customers, as when the costs of service at issue are fully capable of base rate recovery, (b) adjust rates on the basis of only selected costs elements without considering other (possibly offsetting) costs, revenue changes, or other factors that affect the utility's overall profitability (also known as single-issue ratemaking), (c) distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process, or (d) create cross-subsidies or otherwise result in unfair cost recovery. Because Rider VBA falls short of these criteria, IIEC opposes its implementation.

IIEC asserts that the current regulatory framework provides all interested parties with a fair opportunity to review all items affecting cost-based rates. At the same time, IIEC continues, the existing regulatory framework provides utilities an opportunity to earn a fair return. With Rider VBA, IIEC argues that AIU is inappropriately attempting to shift the risk of non-recovery of anticipated revenues to customers. Currently, AIU's shareholders bear the risk that earnings could be adversely affected between base rate cases due to increases in costs or a reduction in revenue. Conversely, AIU's shareholders benefit if the AIU gas utilities can successfully reduce costs or increase revenues between rate cases. IIEC contends that these facts create a powerful incentive for AIU to operate cost-effectively and to promote economic development efforts in its service areas, increasing revenues, and improving AIU's bottom line between base rate cases. IIEC states that Rider VBA would essentially make AIU indifferent to the impact of fluctuations in sales levels in the service areas, eliminating this incentive.

6. AARP's Position

AARP opposes implementation of Rider VBA. While AIU claims that it "needs" this rider, AARP states that AIU has not provided an analysis of whether overall gas revenues are increasing. As illustrated by AG/CUB witness Brosch, AARP reports that AIU's actual margin revenues have been relatively stable over the past 13 years, in spite of weather fluctuations and in spite of a supposed downward trend in usage. AARP states further that the addition of new customers has historically served to offset most or all of the declining usage per customer noted by AIU. AARP concludes that there is no need for this piecemeal Rider VBA (which would not simultaneously recognize increases in customer numbers) based upon the evidence in the record of this case.

Despite the fact that AIU emphasizes that this rider would be ~~symmetrical~~, AARP argues that it would clearly tip the regulatory scales against consumers and grant an almost guarantee to the utility's margin revenues. Mr. Brosch argues that specific margin revenues should not be guaranteed. Such guarantees, AARP contends, fundamentally undermine the entire premise of rate of return regulation, forcing consumers to pay the utility a rate of return while shifting the risks of doing business onto those same consumers. AARP reports that calculations show that based on historical records, AIU would have collected an additional \$38.8 million in gas delivery charges from consumers from 2004 through 2006, a cumulative impact of 7.1% of overall margin revenues over that period of time.

Not only is the Rider VBA a piecemeal approach as to the rate of return formula for ratemaking, AARP notes that AIU's proposal is piecemeal as to its overall operations in that it is being proposed for its gas operations, but not its electric operations. AARP relates that the reason given by AIU was that electric sales per customer are not currently declining, and thus an electric decoupling rider would likely produce less revenue for AIU. AARP avers that such a response clarifies that the utility's goal is actually revenue enhancement, not the removal of any ~~disincentive~~ regarding energy efficiency programs.

Furthermore, AARP suggests that the Commission should not embark upon another new decoupling pilot program, at least not until the People's Gas decoupling rider (just approved on February 5, 2008) is allowed to run its course and is then evaluated. Launching straight into another similar ~~pilot~~ may satisfy some sense of uniformity between regulated utilities, but according to AARP it would be to the detriment of yet another group of consumers without any proof that this specific utility truly ~~needs~~ such a mechanism. If a pilot program is to mean anything, AARP asserts that it should at least be used as an experiment to test the necessity for such extraordinary mechanisms and to analyze how much more ratepayers actually wind up paying.

Moreover, AARP continues, the Commission may learn from the People's Gas pilot what unintended customer reactions may develop when the benefits of

conservation are taken away from natural gas consumers. AIU discusses how Rider VBA would reduce its “disincentive” to support energy efficiency efforts, but according to AARP it did not discuss what impact the Rider VBA would have on customer behavior. Mr. Brosch concludes that Rider VBA will likely diminish the incentive for consumers to lower their thermostats, invest in energy efficient appliances and weatherization, or to participate in the very programs that AIU claims it wants to provide. AARP believes that many of its members will likely feel discouraged from engaging in conservation, knowing that any overall gains in conservation would be quickly diminished by the operation of this rider.

7. Commission Conclusion

Rider VBA as proposed only applies to GDS-1 and GDS-2 customers of each gas utility. The Commission therefore understands that AIU is most concerned about declining gas usage by these two customer classes. Of the fixed delivery service costs recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service costs are recovered through the monthly customer charge. Whenever gas usage by these two classes falls below the test year usage level, AIU's ability to recover that portion of its fixed costs collected through the volumetric charge is impaired.

Why AIU would want to recover as much of its authorized revenue requirement as possible is clear. AIU has proposed Rider VBA as a means of recovering its fixed costs through the continued use of volumetric charges. In Docket Nos. 07-0241 and 07-0242 (Cons.), the Commission recently approved the use of a similar rider for Peoples and North Shore as a four year pilot program. From this decision, it is evident that the Commission is willing to consider alternatives to the traditional method of recovering a portion of fixed costs through the volume based portion of the bill.

The Commission is fully aware that its decision in Docket Nos. 07-0241 and 07-0242 (Cons.) was controversial. Many of the same parties involved in that proceeding have participated in this proceeding and made many of the same arguments regarding AIU's proposed Rider VBA. The Commission acknowledges those concerns and reevaluated them in this proceeding.

What carries the most weight is the argument that the Peoples/North Shore Rider VBA was approved as a pilot program, and it would make little sense to expand the pilot program to AIU without having any of the results from Peoples' and North Shore's experience. AIU's proposed Rider VBA is very similar, if not substantively identical, to the Rider VBA approved in Docket Nos. 07-0241 and 07-0242 (Cons.). If there are unknown flaws in the approved rider, it is likely that the same flaws exist in AIU's proposed rider. Allowing Peoples and North Shore to implement this controversial rider under the pilot program, and hopefully identify any problems with the rider, before expanding it to a significant number of additional customers seems more prudent than

expanding the rider now without the benefit of any significant experience with the rider. Furthermore, using an alternative to Rider VBA that would still provide AIU a better opportunity to recover its fixed costs will supply the Commission more information with which to evaluate ways to recover a utility's fixed costs.

An alternative to Rider VBA that would still promote fixed cost recovery by the utility is recovery of a greater portion of fixed delivery costs through the fixed monthly charge to all affected customers. AIU makes this suggestion and notes that under this method, utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. The Commission concurs with these statements and notes further that this alternative arguably decreases any disincentive AIU may perceive to implementing gas efficiency programs. Specifically, AIU has pending before the Commission in Docket No. 08-0104 a gas energy efficiency plan which it indicates is contingent upon approval of Rider VBA. The Commission anticipates that in light of the end result under the conclusion on this issue, AIU will not shy away from efforts to decrease gas consumption by its customers.

Accordingly, the Commission concludes that it will not adopt AIU's Rider VBA, but that it will direct AIU to increase its monthly customer charge for the GDS-1 and GDS-2 classes to recover more of its fixed delivery services costs. AIU proposes a monthly charge of \$15.00 for all GDS-1 customers. AmerenCILCO's current monthly residential customer charge is \$11.80. The current monthly charge for AmerenCIPS Metro-East residential customers is \$15.00. For all other AmerenCIPS residential customers, the monthly charge is currently \$10.50. The standard monthly charge for AmerenIP residential customers is currently \$10.27, while the non-standard monthly charge is \$32.46. The current and proposed monthly customer charges for small general service under GDS-2 vary depending on meter facilities and whether a customer is a sales or transportation customer. Ameren Ex. 12.2G identifies the current and proposed monthly charges. As mentioned earlier, AIU's proposed monthly customer charges for GDS-1 and GDS-2 customers would recover nearly 57% of AIU's proposed fixed delivery services costs. AIU should modify its monthly customer charges for these classes to recover 80% of the fixed delivery services costs approved in this proceeding. With regard to varying charges for the GDS-2 class, the increases should be proportionate to existing rates. The Commission anticipates that this method of recovering fixed delivery costs will be simpler and easier for customers to understand than Rider VBA.

The Commission does not at this time approve recovery of all fixed costs in the monthly charges for two reasons. First, it is expected that leaving a portion of fixed costs to be recovered through the volumetric rate will encourage AIU to seek ways to improve efficiency and otherwise cut costs. Second, as the number of AIU's customers grows, AIU should experience growing revenue. If all of its fixed costs were recovered through the monthly charge, AIU may arguably over-recover its fixed costs through the monthly charge.

In order to gain sufficient experience to evaluate this method of recovering fixed delivery costs, the Commission anticipates that the approved ratio of fixed costs recovered from the customer charge and the volumetric rate must remain in place until at least December 31, 2012. AIU may propose revisions to this ratio in its next rate case or rate design case thereafter. By this time the Commission should also have the benefit of Peoples' and North Shore's experience with Rider VBA.

In their respective Brief on Exceptions, Staff and the AG complain that increasing the monthly customer charge to recover a greater portion of fixed costs will be detrimental to GDS-1 and GDS-2 customers. While the Commission acknowledges that the monthly charges will increase and such increases may be more apparent on bills than changes to volumetric rates, the fact remains that the volumetric rates will decrease by a corresponding amount. Therefore, on average, there should be no overall adverse revenue impact on customers resulting from recovering a greater portion of fixed costs through the monthly customer charge than a volume based rate. So that customers realize this, however, the Commission directs AIU to include in at least one bill insert soon after entry of this Order a statement explaining that a greater portion of the fixed costs of delivering gas will be recovered through the monthly customer charge and that the amount of fixed costs recovered through the volumetric charge has been correspondingly reduced.

B. Rider QIP

1. AIU's Position

AIU states that it intends to improve infrastructure performance (i.e., system reliability) by increasing both O&M expenditures and capital expenditures. Specifically, AIU states that it plans to spend \$909 million in electric capital expenditures for the 2007-2009 time period. Over two-thirds of these capital expenditures, AIU continues, will be dedicated to infrastructure improvement.

Certain factors, however, limit its ability to make infrastructure investments, according to AIU. Obviously, access to capital funds is necessary. AIU explains that some of those funds are provided by cash flow from operations, based on the revenue requirement and rate base from the most recent rate case. AIU claims, however, that cash flow from operations will be insufficient to make such improvements based on a static rate base and revenue requirement. AIU says that it will therefore have to go to the capital markets to secure funds for infrastructure investments. Without a ready source of rate recovery for capital investments, AIU states further that there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors. In other words, AIU is asserting that significant and continued investments in infrastructure can only be made, and sustained, when a fair return on and a return of investment are received on a timely basis. AIU adds that capital investments made between rate cases cause earnings and return on equity to fall, further impairing the ability to raise capital.

AIU indicates that it can address the regulatory lag issue in one of two ways: (1) delay projects so they are timed with a rate case; or (2) create a rate mechanism to reflect such incremental projects in rates on an on-going basis, subject to Commission review and reconciliation. AIU proposes the incremental approach, which includes the capital costs of projects in rates as they are completed and placed into service. Thus, AIU is seeking approval of Rider QIP to provide timely recovery of capital costs for certain distribution plant investments, thereby allowing continued investment in infrastructure. The rider would recover costs associated with a defined set of plant additions beginning after December 31, 2007.

AIU proposes to limit the project expenses recoverable under Rider QIP. For example, capitalized expenditures related to existing distribution plant would qualify for the rider. Plant additions associated with new customers would not qualify for the rider, because those projects would produce additional revenue. AIU explains that these criteria are consistent with its goal to make its system stronger and more durable because capital expenditures on existing distribution plant are made to either enhance the system or replace existing plant to increase system reliability.

Customers will benefit from the projects eligible for Rider QIP cost recovery, according to AIU, through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced. AIU indicates that these are not the only types of system improvements that could benefit customers. Additionally, AIU states that investments may be required as a result of the Commission-mandated audit of AIU's delivery systems and storm preparedness when recommendations are received in 2008. AIU states further that it is studying —smart metering” and —smart grid” technologies that may provide future benefits to customers.

The concepts of smart metering and smart grid are currently being defined as the transformation of the electric delivery system of the 20th century into the delivery system of the 21st century. Many envision the system of the future as one that will continue to use the same types of equipment that are used today for electric delivery – e.g., power lines, substations, and transformers – but also picture it as a fully automated delivery network that monitors and controls every customer and node, ensuring a more reliable flow of electricity and a two-way flow information between the power plant and the appliance, and all points in between. AIU reports that smart metering, in addition to measuring electricity usage and voltage on a real-time basis, allows for two-way communication and provides the utility with new capabilities for operating and managing the delivery system. Smart metering coupled with communication functionality could enable utility customers to see and understand how and when they consume electricity. This in turn, AIU continues, will provide consumers the ability to manage their consumption of energy and take advantage of time-based rates – shifting usage of energy from peak periods or high-cost periods, taking steps to conserve electricity, and reducing their energy costs.

Furthermore, while smart meters will satisfy traditional metering needs for the utility – the measuring of the consumption of energy for system design and billing

purposes - they could also serve as portals into the consumers' homes or businesses. AIU contends that smart meters will add additional value for both the consumer and the utility when the information they provide and the communication capabilities are used to enable distribution automation, demand response, load management, and real-time pricing. As the electric delivery system or grid continues to evolve, AIU submits that smart meters could become an integral part of an array of intelligent electronic devices that will make up what is conceptually referred to now as the —smart grid.”

AIU indicates that it has already invested in advanced meter reading ("AMR") technologies--beginning a 4-year deployment of automated meter reading technology in May, 2006. AIU states that its commitment to the deployment of AMR technologies has required and will continue to require a significant investment in new and retrofitted meters, data gathering equipment, and telecommunications and information processing systems. Benefits that AIU anticipates deriving from AMR technologies include, but are not limited to, reduced meter reading costs, improved reliability, and enhanced restoration efforts through remote detection of customer outages.

In addition to implementing some level of AMR technologies, AIU states that it intends to begin studying the costs, benefits, and steps that would be necessary to implement smart meters and the smart grid for residential and small commercial customers. As of this year, AIU has begun assessing and comparing the current state of the energy infrastructure in the region to future scenarios involving smart grid technologies. AIU also plans to identify additional programs and potential tariff offerings that would allow customers to begin to take advantage of some of the benefits of smart metering. AIU argues that Rider QIP would facilitate investments in smart metering and a smart grid.

In an effort to address some of the concerns expressed by Staff and interveners, AIU modified its original Rider QIP proposal. In particular, AIU proposes to change the definition of Rider QIP projects to include only those associated with system modernization or service reliability enhancements. Further, before any project costs can be recovered through Rider QIP, AIU says that it will file a cost/benefit analysis. AIU has committed to make any such filing on or before April 1st of each applicable calendar year, providing nine months to review and approve any Rider QIP charges prior to the subsequent January 1 effective date. Parties could intervene in a Commission proceeding initiated after the filing of a cost/benefit analysis and express their views on which projects or initiatives, if any, should qualify for rider recovery. The Commission would then decide which projects or initiatives qualify.

AIU believes that the cost/benefit analysis should also address the concerns of the AG, IIEC, and AARP regarding the shifting of risk to customers and loss of incentives for the utility to behave in a prudent manner if Rider QIP is approved. AIU argues that these claims should be disregarded since passing a cost/benefit test at the Commission must precede timely recovery of the costs associated with a project. This process, AIU continues, results in maintaining the status quo, especially in times of escalating costs. Moreover, AIU states that each utility is still bound thereafter to justify

the prudence of the expenditures actually made in an annual prudence review. AIU asserts that it has every reason to behave in a manner that ensures that the Commission will not disallow costs. To mitigate the impact of reviewing Rider QIP on the Commission's resources, AIU offers to pay a combined \$100,000 annual filing fee. Concerning operational risk, AIU insists that Rider QIP does not shift operating risk; instead, it neutralizes operating risk.

AIU acknowledges AG/CUB witness Brosch's concern that Rider QIP does not take into consideration updates to the depreciation reserve, deferred taxes, and O&M expense. He also states that Rider QIP does not consider potential savings related to new plant investment. To address such concerns, AIU will be filing an annual rate of return report along with each Rider QIP filing to the extent that the subject costs are being recovered through the rider. The annual rate of return report will contain updated depreciation reserves, deferred taxes, and O&M expenses, which the Commission may consider when evaluating whether or not to allow Rider QIP recovery. AIU indicates that if the Commission determines that AIU is exceeding the allowed return, or if it believes potential savings, if any, from a project or initiative will cause AIU to exceed the allowed return, the Commission can choose not to allow Rider QIP recovery. Additionally, AIU agrees that Rider QIP can stand as a pilot program through and including December 31, 2012. Thereafter, AIU would need to re-file Rider QIP or some variation of the rider if they seek to continue to recover costs in such a manner.

Staff witness Lazare's suggestion that AIU use a future test year to recover anticipated project costs does not sway AIU. AIU claims that a future test year does not adequately address its concerns regarding regulatory uncertainty. AIU states further that a future test year is difficult to prepare and both costly and burdensome.

AIU does not oppose Staff witness Stoller's recommendation that the Commission take up this type of rider in a broader proceeding, outside of a rate case. AIU states that the Commission should give serious consideration to initiating a proceeding to examine what it claims are "evolving" service quality standards. But at the present, AIU is willing to make Rider QIP a pilot program now, with a definite expiration date. AIU believes that the expiration date should address Mr. Stoller's concern since it allows the Commission to consider a permanent program or rule in a broader proceeding, while allowing Rider QIP to go into effect in the meantime.

In response to Mr. Brosch and IIEC witness Stephens arguing that the infrastructure project costs are predictable and controllable and therefore do not warrant rider treatment, AIU contends that there needs to be recognition of changing times and public policy. AIU points out that in the Rate Relief Bill (Public Act 95-0481) passed last summer, there was recognition that the State, through electric utilities, would pursue energy efficiency and demand response programs and technologies. As part of that policy, the General Assembly authorized the use of an automatic adjustment clause rider to be approved by the Commission to recover the subject costs. Similarly, AIU continues, the General Assembly in late 2006 passed legislation mandating residential real time pricing. A rider was also authorized that would allow the utility to recover its

costs. AIU recognizes that these are legislatively mandated riders, but reasons that the Commission is an extension of the General Assembly and is fully capable of promoting public policies as well.

Mr. Stephens speaks of the opportunity for the utility to enhance cost recovery in between rate cases, as does AARP witness Smith. AIU contends that a utility may have been more opportunistic in between rate cases when it owned generation, when increased load growth, off-system sales, or hot summers would have increased revenue. Today, however, AIU maintains that a utility without generation does not experience the same benefits as a generation-owning utility that would allow it to absorb the lag associated with significant delivery investment without adversely affecting earnings. Similarly, AIU does not accept Mr. Smith's claim of increased revenues between rate cases since AIU contends that costs will continue to escalate.

2. Staff's Position

Staff recommends that the Commission reject AIU's proposed Rider QIP as it represents a deviation from traditional regulation that would add significant costs for ratepayers and to the regulatory process without providing any tangible benefits. Staff acknowledges that AIU anticipates capital expenditures of \$909 million for its electric systems over the 2007-2009 time period. Staff also understands that AIU is concerned about the regulatory lag associated with recovering these costs through the traditional rate case process. AIU's arguments in support of Rider QIP, however, do not sway Staff. Staff points out that rider recovery should be reserved for highly volatile, uncontrollable, and/or unpredictable costs--a standard which even AIU recognizes. Yet none of AIU's arguments, Staff notes, suggest that these costs are volatile, uncontrollable, or unpredictable.

If AIU expects to incur significant costs in the future, Staff suggests that a more reasonable approach would be to file a rate case based on a future test year. A future test year could be designed to recover future investments that may not be appropriately captured in an historical test year. In response to AIU's concerns that a future test year is difficult to prepare, costly, burdensome, and rarely used, Staff identifies three pending rate cases using future test years: Docket No. 07-0507 (IAWC), Docket Nos. 07-0620, 07-0621, and 08-0067 (Cons.) (Aqua), and Docket No. 08-0363 (Nicor). If smaller water utilities have the capability of employing future test years, it is not clear to Staff why AIU should find a future test year prohibitively difficult to prepare or too costly and burdensome to implement. Staff asserts that AIU's concerns about regulatory uncertainty should be dismissed as well. Staff avers that the requirement that reasonable justification for system upgrades be provided in the ratemaking process is essential to protect the interests of shareholders and ratepayers alike. Furthermore, Staff states that AIU can reduce regulatory uncertainty by providing strong support for the proposed investments.

Staff also understands that AIU is considering smart metering and smart grid technologies. The problem that Staff has with AIU's interest in such technology is that it

is not clear whether Rider QIP is being proposed to make the system more reliable, to transform it technologically, or to do both. The fact that the language of the rider and AIU witness Nelson's discussion of smart meters and the smart grid are both open-ended raises a concern for Staff that approval of Rider QIP will give AIU a license to transform the distribution system beyond the ability of ratepayers to pay the corresponding costs. As the events of 2007 clearly indicate, the concerns of ratepayers appear to be with the levels of their electric bills.

In response to Mr. Nelson's claim that customers would not pay any more for reliable service under Rider QIP, Staff argues that the reality would be the opposite. In between rate cases, Staff asserts that AIU would be able collect additional amounts from customers, which contrasts with traditional ratemaking where utilities can not pass along additional costs once rates are set. Moreover, Staff contends that AIU fails to provide adequate reason why ratepayers should be asked to pay an extraordinary price for what appears to be ordinary electric service. Mr. Nelson testifies that customers will benefit from Rider QIP —through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced.” (AmerenCILCO Ex. 2.0E at 30; AmerenCIPS Ex. 2.0E at 30; AmerenIP Ex. 2.0E at 30) Staff maintains that this higher quality of service is something ratepayers should normally expect from AIU—it should not be something for which they have to pay extra. Furthermore, Staff relates that AIU has a statutory obligation to provide safe and reliable service at minimum cost. Staff argues that AIU should not receive an additional financial reward, as would be provided by Rider QIP, to fulfill this obligation to maintain a safe and reliable system.

AIU examined two other riders when drafting its proposed Rider QIP. One is the Qualifying Infrastructure Plant Surcharge Rider of IAWC. The second is the Infrastructure Cost Recovery Rider proposed in the recent North Shore/Peoples rate case. AIU argues that following a similar approach to these riders supports the Commission's goal of promoting —uniformity of common riders.” The similarity of Rider QIP to the North Shore/Peoples proposed rider, however, causes Staff to urge caution since the Commission rejected the North Shore/Peoples proposed rider. (See Docket Nos. 07-0241/07-0242 (Cons.), Order at 162) Staff argues that AIU has failed to provide the full range of information discussed by the Commission and, therefore, AIU's proposed Rider QIP falls short of the standard set in Docket Nos. 07-0241/07-0242 (Cons.).

Staff recommends further that if the methodology for recovering investments in infrastructure is to be changed, that change should not be made in this rate case. Staff witness Stoller argues that the facts and policies involved should be thoroughly reviewed in a focused and separate proceeding. Mr. Stoller suggests that the Commission give serious consideration to initiating a proceeding to examine "evolving" utility service quality standards, and possibly to changing the provisions of the Commission's rules at 83 Ill. Adm. Code 410, "Standards of Service for Electric Utilities and Alternative Retail Electric Suppliers" ("Part 410"), and 83 Ill. Adm. Code 411, "Electric Reliability" (~~Part~~ 411”), consistent with modifications, if any, that need to be made to those rules regarding electric distribution system investment.

Mr. Stoller discusses AIU's perception of its inability to earn a fair return on investment in the maintenance and modernization of utility distribution systems. While utilities earn a return of and on their investment in their distribution systems, he notes that Mr. Nelson questions whether utilities earn a sufficient return on their investment to warrant investment that will improve their systems. Mr. Stoller states that the broader question may be whether the regulatory process effectively addresses distribution system reliability and whether changes are warranted to improve utility distribution systems. Answers to those broad policy questions would affect not only AIU, Mr. Stoller observes, but all utilities in Illinois.

Concerning the specifics of Rider QIP, Mr. Stoller does not offer a specific definition of what constitutes system modernization, but indicated that those are generally the type of projects to which he believed any expedited cost recovery mechanism such as Rider QIP should apply in its potentially broadest application. Mr. Stoller also recommends completely eliminating language that would make Rider QIP applicable to “~~service~~ reliability enhancements,” saying that he believes that that definition is far too broad. Additionally, Mr. Stoller testifies that he does not believe that all utility work on a distribution system that could be claimed, or even agreed, to enhance service reliability should necessarily be entitled to expedited cost recovery. Such work could easily include such traditional projects as replacing old and rotted poles or simply replacing old distribution lines. Mr. Stoller acknowledges that while he is well aware that those projects can be valuable in maintaining and enhancing reliability, his position is that the Commission needs to be far more careful in defining what utility projects are entitled to expedited cost recovery treatment than to simply include in that category all projects that can be claimed or even demonstrated to enhance reliability.

If Rider QIP is implemented, Mr. Stoller agrees that a periodic filing and approval proceeding process would be a suitable approach. He is not prepared to agree that going through a process each year would be necessary or advisable, but states that having a known and predictable process in place would be beneficial for planning purposes for any party that might be interested in participating. He submits that perhaps the process should only occur at two-year intervals and perhaps the Commission approval process should be longer than the nine-month process that Mr. Nelson recommends. Mr. Stoller does not claim to have the answers to such questions, but suggests that they are questions that could be resolved in the collaborative process he recommends. Staff believes that Mr. Nelson's offer of payment to accompany such a filing is neither appropriate nor authorized by statute. Staff is concerned that the payment would create the appearance of impropriety.

If the Commission opts to follow his recommendation of a collaborative process, Mr. Stoller states that the participants should consider and make recommendations to the Commission regarding (1) the appropriate technological route or routes to follow for smart grid or other utility plant investment, (2) how to define which utility projects should be eligible for Rider QIP, or some other form of expedited cost recovery consideration, and (3) the process through which projects that might be considered for expedited cost

recovery treatment should be proposed, evaluated, and approved and the time limitations for doing so. Mr. Stoller suggests that the collaborative process move on an expedited basis, but should not be time-limited in advance. He explains that neither the Commission nor any potential party knows at this time just how much information the parties might find it necessary to examine and how much time the parties may need to make recommendations. Only when the collaborative process is completed, and the Commission adopts the recommendations that it finds appropriate, does Mr. Stoller believe that Illinois utilities should file for Commission consideration a Rider QIP-type tariff, or if the Rider QIP tariff has already been approved in this proceeding, begin proposing projects for expedited cost recovery consideration and treatment.

3. AG's Position

The AG opposes implementation of Rider QIP. Some of the AG's general arguments regarding the appropriateness of riders in the above discussion of Rider VBA are also applicable to Rider QIP. Generally, with regard to Rider QIP, the AG contends that AIU has not provided any evidence of financial need for a rider for future distribution plant investments. In addition, the AG finds that the proposed Rider QIP is conceptually and mechanically flawed, would add considerable administrative burdens for Staff, interveners, and the Commission, and approval of the rider would conflict with the parameters of utility ratemaking outlined both in the Act and by Illinois courts.

a. Rider Treatment Eligibility

AG/CUB witness Brosch describes the general criteria employed by regulators to evaluate riders that are proposed as exceptions to traditional test year period regulation. The AG argues that Rider QIP fails every one of the general criteria that are routinely relied upon by regulators to evaluate rider proposals and highlighted by Illinois courts as appropriate for rider recovery. The AG asserts that the continuing investments that AIU makes in electric distribution are clearly not —~~highly~~ ^{highly} volatile or unpredictable,” as evidenced by the fact that AIU management is able to control and budget such costs and make decisions regarding prioritization of capital spending. On the contrary, the AG observes, continuing plant investments are subject to rigorous investment screening, as discussed by AIU witness Getz, and only very gradually contribute to changes in rate base.

Likewise, the AG contends that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future *budgeted* electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of \$157 million. Minimum spending of \$121 million (23% less) occurred in 2005 and maximum planned spending of \$181 million (15% more) is budgeted in 2008. AIU's historical *actual* capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006, the AG reports that actual annual Gross Construction Expenditures, as shown on page 5 of AIU's First Revised Schedule WPD-7, have ranged from \$54 to \$57 million per year

for AmerenCILCO, \$45 to \$82 million for AmerenCIPS, and \$134 to \$177 million for AmerenIP.

Moreover, the AG asserts that new electric distribution plant investments can create productivity improvements and reductions in expenses that help AIU mitigate the costs of increasing capital investments. Significant amounts of electric distribution spending is targeted for reliability projects that are responsive to problem areas prone to excessive outages – and when older, unreliable plant is replaced, the AG states that savings are expected because of reduced outage restoration effort and expense in those areas. There are also opportunities, the AG adds, to deploy new technologies within the electric distribution network that are intended to capture expense savings. The AG points to the previously discussed four-year AMR project that began in 2006. AIU plans to expand AMR to an additional 1.1 million meters in Illinois by the end of 2009. The AG states that the primary reasons for investing in this large project are savings in operating cost and improvements in customer service enabled by AMR technology. The AG notes that AIU elected to deploy AMR under traditional regulation and without any extraordinary Rider QIP ratemaking treatment.

The amount of money to be generated by Rider QIP likewise is not significant enough in relation to the total revenue requirement to justify rider treatment, according to the AG. In its response to Data Request No. AG-1.30, AIU provides illustrative calculations of the quarterly Rider QIP calculations that would apply to its “forecasted 2007 distribution plant additions” totaling \$36.1 million. At this assumed spending level, the AG states that Rider QIP incremental quarterly and annual revenues would be \$200,000 and would steadily ramp upward between rate cases as more plant is added each quarter. Extrapolating projected distribution plant additions at this pace, the AG continues, would suggest estimated annual revenue impacts of approximately \$2.0 million in year one, \$5.4 million in year two, and \$9.2 million in year three (assuming no rate cases). While AIU has not justified its financial need for any of this incremental revenue, the AG goes on to say that by year three the incremental revenue of \$9.2 million and corresponding incremental income after taxes of about \$5.5 million is clearly not large in relation to total proposed electric utility operating income for the utilities of \$189.3 million. Because the revenue requirement impact translates into only about 16% of the dollar amount of incremental capital spending, the AG asserts that AIU would need to vastly expand its planned electric distribution capital spending to experience the large or potentially volatile revenue requirement impacts that are normally required for special rider approval.

Furthermore, the AG insists that there is no evidence that traditional regulation has precluded AIU from taking advantage of cost effective opportunities to make or accelerate capital expenditures. The AG observes that to date, AIU has successfully modernized its network and, generally speaking, maintained reliability over the years, without benefit of an automatic rider recovery mechanism for distribution system modernization projects. AIU has been investing hundreds of millions of dollars in new plant every year in the normal course of business. Additionally, the AG notes that AIU fails to identify any particular investment project required to meet its service obligations

to its customers that it could not make because of the absence of a mechanism like Rider QIP. Also of importance, the AG adds, is that all of those expenditures historically made by AIU were incurred without advanced Commission approval.

b. AIU's Current Budget Process

The AG reports that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. Similarly, Mr. Getz confirms that AIU has not specifically identified any projects that will be proposed in the rider. The AG professes amazement that Mr. Getz is unaware at this point as to how the Rider QIP process is to work. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects — ~~that~~ ^{but} may not make the cut today.” (Tr. at 606) This raises a question for the AG of whether the preferential ratemaking under Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses. (See generally Tr. at 600-606)

If Rider QIP is adopted, Mr. Brosch is concerned that the incentive for utility management to act prudently with expenditures between rate cases will be lost, or at least diminished. According to the AG, Mr. Getz confirms the efficiency of AIU's existing budget process under traditional regulation. Mr. Getz testifies that the existing method begins in April and typically ends in December. According to Mr. Getz, and AG Cross Exhibit 6, capital budgets are created for each of the three utilities based on approximately 20 internally defined budget groups, such as line transformers, meters, and distribution substations. Blanket or standing work orders are budgeted in April and reviewed by a Central Review Committee ("CRC") of managers to see if they seem reasonable in terms of the dollars that are identified and the rationale provided. The business performance supervisor reviews these in May. The process is designed, according to Mr. Getz, to ensure that allocated dollars are efficiently earmarked to ensure the availability of dollars for specific projects. Mr. Getz states that some projects are sent back to individual budget groups as rejected for further refinement. He adds that revisions are sometimes made to estimates. (See generally Tr. at 607-612)

The AG continues to describe AIU's budgeting process by relating that Mr. Getz testifies that engineers submit specific projects for consideration into the Integrated Spending Prioritization (“ISP”) Tool during May of each year. These projects are typically valued at \$100,000 or more. The ISP Tool is an “optimization program” with weightings based on safety, System Average Interruption Frequency Index reliability, and other factors that are applied to each specific project to rank the projects. According to Mr. Getz, the CRC meets in June to review specific project prioritization through the ISP Tool as well as budgeting personnel prioritization based on preliminary capital targets from the Treasurer's organization. Hard capital targets are established in August and any adjustments that need to be made are done so by the CRC. At this point, Mr. Getz explains, AIU is trying to “fine tune” the capital budget, with another

review of the budget numbers developed in June. The recommended budget is then forwarded to the AIU President and Vice Presidents for review. (See generally AG Cross Exhibit 6 and Tr. at 613-616)

Mr. Getz confirms that this capital budget process is designed to include checks and balances that contribute to the provision of reliable service while maintaining AIU's shareholders' and ratepayers' financial interests. In addition, he verifies that this budget process helps ensure that AIU invests in capital projects that are needed for both reliability and to meet customer demand for services. Mr. Getz asserts that the existing capital budget process ~~—does~~ a good job of prioritizing" capital spending, and that these checks and balances have helped ensure that AIU's electric rates are least cost from the customers' perspective. (Tr. at 618)

The AG finds it ironic that, if approved, Rider QIP would reduce the normal regulatory lag incentive that a utility faces between rate cases, and provided evidence of such incentive in the above-described AIU capital budget process. Such a reduction serves to encourage careful management and optimization of capital expenditures. The AG is concerned that Rider QIP would provide expedited piecemeal rate increases for incremental qualifying capital investment between rate case test years, and diminish management's obligation to carefully manage and optimize capital expenditure levels. When asked during cross-examination whether Rider QIP projects would run through the existing capital budget process, the AG reports that Mr. Getz testified that he was ~~—not~~ sure what the plan is going forward, or, you know, what the process is envisioned to be." (Tr. at 598)

The AG further argues that there is no evidence that AIU faces a financing problem that makes Rider QIP necessary. The AG notes AIU witness Nelson's testimony that, "(w)ithout a ready source of rate recovery for capital investments, there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors." (AmerenCILCO Ex. 2.0E at 28) The AG considers it significant that Mr. Nelson does not state that AIU is unable or unwilling to invest in new plant. The AG asserts, that AIU enjoys considerable cash flow from its regulated operations in Illinois and expects to continue to be able to finance most of its planned construction expenditures from internally generated cash flow from operations. In its response to Data Request No. AG (MLB) 3.09, AIU provided its most recent confidential financial projections of income, balances sheets, and cash flows for the years 2008-2010 assuming no rate relief is granted in the pending rate cases. Mr. Brosch finds it instructive that AIU expects to generate virtually all of the capital needed to finance planned construction activities in Illinois from the cash flows produced by consolidated utility operations (rather than capital markets), as shown in the proprietary table at page 61 of his direct testimony. From this information, the AG contends that it is clear that Rider QIP is not needed by AIU to provide access to capital markets on reasonable terms, because traditional ratemaking and the strong cash flows arising from operating income and the collection of depreciation for existing plant service generates most or all of the cash required by AIU for new investment in Illinois.

c. Ambiguity Concerns

Under Rider QIP, capitalized expenditures related to existing distribution plant, but not those additions associated with new customers, would qualify for the rider. In addition, the rider lists nine accounts for which cost recovery under Rider QIP is possible. According to Mr. Nelson, Rider QIP projects include only those "associated with system modernization or service reliability enhancement." The AG, however, is still concerned that the terms of Rider QIP may permit AIU to recover nearly any plant investment under Rider QIP. For example, the AG notes that under cross-examination, AIU witness Cooper acknowledged that the majority of capital investment projects for electric delivery service would be listed under these nine accounts. (Tr. at 514)

Additionally, Mr. Brosch notes that it is often difficult to distinguish whether specific electric distribution projects are partially driven by growth in customer demand. The AG argues that new investments made to extend distribution lines and to connect new customers with meters and services should clearly be excluded from Rider QIP because AIU desires retention of new business margin revenue for its shareholders between test years. Mr. Brosch adds that construction costs incurred to replace existing facilities with larger and newer facilities may not be solely related to either growth or reliability, but instead be driven by a combined need to replace obsolete or unreliable equipment as well as a need to expand capacity of existing circuits. When asked in Data Request No. AG 1.39(b) to clarify how Rider QIP would apply to "~~capital~~ expenditures that are made to increase the capacity of existing primary distribution feeders to accommodate growth in demand caused by new customers in the area served," the AG relates that AIU responded, "~~If~~ the reason for the distribution feeder project was triggered *solely* by the demand growth of new customers added subsequent to the test year period for the most recent rate case, then none of the project capital expenditures would qualify for QIP treatment" (emphasis added). The AG interprets this to mean that any project driven jointly to meet demand growth and address reliability concerns would fully qualify for Rider QIP inclusion, under this liberal interpretation of the project inclusion criteria AIU is proposing for the rider.

With regard to the phrase "system modernization or service reliability enhancement," Mr. Brosch notes that "~~system~~ modernization" is a vague term that is not defined anywhere in AIU's rebuttal testimony and could be construed to include virtually any project that employs currently available materials or technologies to replace older, existing plant assets. The same is true, he continues, for the new "~~service~~ reliability enhancement" classification proposal, because the replacement of nearly any older or deteriorated plant asset with newer materials or equipment could reduce the possibility of failure and customer outage and thereby enhance reliability.

With respect to the proposed filing of cost/benefit analyses, the AG is troubled by the fact that no details are provided to explain what methodologies or cost/benefit metrics are to be employed or what level of detail or accuracy will be contained in such "~~analyses~~." Given the vague definition of types of modernization or reliability projects that may be proposed as well as the complete lack of details regarding how the

promised cost/benefit analyses will be performed or measured, it is impossible for the AG to tell how much or little detailed information would be contained in the proposed annual filings and related analyses. The AG believes that it is conceivable that each annual filing by AIU may contain a large number of individual capital projects, each with some level of supporting economic analysis that requires detailed discovery and study by Staff and any concerned interveners before any informed Commission deliberation or approval of charges to customers could occur. In apparent recognition of the regulatory burden these filings would represent, the AG notes that AIU offered to contribute \$100,000 to the Commission to fund Staff (but not interveners') review of these filings. The AG adds that it is unclear whether AIU intends to try to pass this \$100,000 through to customers.

When asked by the AG in discovery to provide a specimen copy of a cost/benefit analysis, AIU responded by stating, —~~The~~ form of the cost/benefit analysis has not yet been drafted; however, AIU intend that it be similar to that which the Commission described in its Order in the recent Peoples/North Shore case.” The AG finds the reference to the Commission’s Order in Docket Nos. 07-0241/07-0242 (Cons.) unhelpful since the Commission did not prescribe any form of cost/benefit analysis. Rather, the Commission listed some additional information that might have made it easier to approve the proposed infrastructure rider. The AG asserts that AIU should not be allowed to implement Rider QIP by simply indicating the intent to comply with cost/benefit analyses that are largely undefined.

In addition, the AG states that Rider QIP is flawed in its failure to account for two elements of the revenue requirement calculation that change in direct relation to changes in gross plant investment – the accumulated deferred income tax reserve and the accumulated depreciation and amortization reserve. Since these balances are treated as subtractions in determining rate base, the AG avers that it is completely unreasonable for AIU to include gross plant additions within Rider QIP and not also include the growing deferred income tax and accumulated depreciation balances that also tend to increase from year to year. Mr. Brosch explains that the rider is driven by quantification of the term —~~Net~~QIP” in the tariff, which includes the —Original cost of QIP less accumulated depreciation.” By defining qualifying investment this way, the tariff completely fails to account for the additional deferred income taxes arising from the incremental plant investment. Mr. Brosch also contends that there is also a problem with the narrowly defined —~~less accum depr~~” term that is used to quantify —~~Net~~QIP.” The accumulated depreciation that is recognized under Rider QIP is limited to depreciation accruals only upon the new QIP Plant investment dollars. According to Mr. Brosch, in reality, AIU continues to collect depreciation and build its Accumulated Reserve for Depreciation based upon application of depreciation accrual rates to all plant investment, not just incremental new investment. In fact, he explains, depreciation on embedded prior year capital investment produces considerable cash flow for QIP that is available for reinvestment in incremental new plant, as shown in Table 9 (page 61) of AG/CUB Ex. 2.0, and that can not be ignored if a balanced tracking of changes in actual net plant investment is to be achieved through any rider tariff.

The AG identifies other mechanical difficulties in auditing Rider QIP. The AG states that neither the input values nor the computations involved in administering Rider QIP plant investment can be readily audited and verified through expedited regulatory reviews. Rider QIP relies upon several input values that should become “fixed” in this rate case, including the gross revenue conversion factor —GRF” and the weighted cost of capital inputs “WCCE,” “WCPE,” “WCLTD,” and “WCSTD.” But, according to the AG, the quarterly capital expenditure amounts in each account that qualify for inclusion in all the calculations would need to be verified for each quarterly filing and then again in annual reconciliation filings, with interest accrued on over and under-recoveries. The complexity of the calculations involved in administering Rider QIP is evident to the AG from the four pages of single-spaced text required in AIU witness Cooper’s testimony just to define the terms involved, before any data is actually analyzed or rates calculated.

AIU apparently contemplates rapid implementation of Rider QIP quarterly rate increases, with an informational filing on the 20th day of the month preceding the effective date of the QIP surcharge percentage, which the AG fears would allow no substantive analysis or audit of the plant costs that would cause such rate increases. The AG believes that Rider QIP raises a fundamental question regarding whether it is necessary for any Staff audit or other regulatory examination to occur before new plant investments can be included within rate base for cost recovery from customers. The primary input values under Rider QIP would be the —NetQIP” recorded original cost plant additions recorded each quarter, reduced by project costs that relate to —~~new~~ business.” In the event the Commission or Staff determine that any prudence review or financial audit of recorded plant investments is required prior to increasing rates to recover the incremental new NetQIP plant investment, the AG states that considerable administrative costs and procedural delays may be unavoidable with implementation of Rider QIP.

d. Legal Considerations

Among the statutory provisions that the AG has considered is Section 9-211 of the Act, which provides that a utility’s rate base shall reflect only the value of such investment which is both prudently incurred and used and useful in providing service to customers. The AG contends that Rider QIP violates this precept since it permits surcharges on customer bills to cover the carrying costs of new investment before there has been any Commission review of the prudence or used and usefulness of the Rider QIP investments. While Rider QIP would include an after-the-fact prudence review as part of the annual reconciliation of the preceding calendar year rider surcharges, the AG points out that customer rates would have already increased, reflecting investment prior to any prudence assessment. The AG also objects to Rider QIP on the legal grounds that it violates the rule on single-issue ratemaking, least-cost requirements, and many of the other legal principles that it discusses in the context of Rider VBA.

4. CUB's Position

CUB objects to the implementation of Rider QIP, citing in defense of its position the rule on single-issue ratemaking, the broad scope of eligible projects under Rider QIP, the lack of any specific project plans, the delay in any customer receipt of savings, and the improper transfer of risk from shareholders to customers. CUB also states that to the extent AIU's request for Rider QIP is based on the eventual implementation of a smart grid, the rider should be rejected given AIU's lack of specificity with regard to smart grid implementation. CUB witness Cohen, though not opposed to implementation of a true smart grid where the benefits outweigh the costs, takes issue with the propriety of rider treatment for smart grid investments. Instead, Mr. Cohen recommends that the Commission order immediate commencement of a collaborative stakeholder process to examine the changing nature of the utilities' service obligations and address the costs and benefits of particular smart grid strategies. He testifies that the stakeholder process should be led by an independent expert facilitator with experience in similar processes elsewhere, who could assimilate the latest technical information and regulatory policy from around the country in a highly specialized and rapidly evolving field. Mr. Cohen believes that a high level of experience with similar processes will enable the facilitator to set the agenda, manage the flow of information, and focus the collaborative on timely achievement of its goals.

Mr. Cohen further recommends that the Commission order a statewide process to consider smart grid and related issues, in order to ensure that uniform principles, policies, and standards are applied where appropriate.

Mr. Cohen and CUB witness Kiesling both testify about the vast potential benefits of a true smart grid, but also caution that such benefits will only be realized if the Commission approaches smart grid planning strategically, and with ratepayers' best interests in mind. Mr. Cohen states that a true smart grid has the potential to facilitate optimal procurement planning as well as other system benefits. Smart grid technologies integrate electric generation, delivery, and consumption systems with communication systems to improve system function and reliability and also potentially to provide a variety of electricity products and services to the diverse range of customers in the electricity network. Further, smart grid holds the potential to reduce operating and maintenance costs while improving reliability, as well as reduce the cost of long-run generation, transmission, and distribution investments by reducing peak load.

Ms. Kiesling lays out the necessary foundations for any smart grid planning process and advises that this Commission should approach smart grid investment from a proactive and strategic policy framework stand point, rather than the reactive approach. She explains why a utility-specific system engineering process is essential at the outset, the danger of premature commitment to a particular technology, and the need to "future-proof" smart grid decision-making. Ms. Kiesling identifies the following characteristics as defining a true smart grid:

- Self-healing: a smart grid can measure voltage and frequency and detect and prevent faults and outages automatically;
- Active agent participation: customers actively participate in the network, as with demand response programs;
- Security: built-in resiliency to external attacks on the network;
- Power quality: customers can demand interruptible power supplies in exchange for lower prices;
- Interconnection: distributed generation and storage sources can interconnect within the network;
- Markets: a smart grid is a transactive, market-based network; and
- Efficiency: a smart grid optimizes resource use and minimizes waste and idle capacity.

To assist in the effective design of a smart grid, she reports that there has been industry movement toward common smart grid architecture. Ms. Kiesling cites the GridWise Architecture Council (“GWAC”), a group of experts formed by the U.S. Department of Energy, as the gold standard in interoperability principles and architectural frameworks to facilitate the smart grid.

Ms. Kiesling testifies that GWAC is dedicated to the development of interoperability principles for the modernization of the electric power network, and to facilitating the implementation of these principles. One of the GWAC’s roles, she continues, is to help stakeholders understand these principles, and to provide resources to help facilitate an interoperable, modern, smart electric power network. The GWAC’s Decision-Maker’s Interoperability Checklist is a tool to help decision-makers evaluate options such as capital asset investments or new information technology opportunities to determine whether they contribute to interoperability. Ms. Kiesling states that decision-makers can use the checklist to review policies or infrastructure investment proposals. She recommends that these standards be applied in a multi-party process that creates a long-term smart grid strategy for AIU.

CUB asserts that the collaborative process recommended by Mr. Cohen and Ms. Kiesling would address foundational policies, as well as incorporate utility-specific issues. CUB states that policies for consideration could include, but not be limited to:

- Defining the intended functionalities and properties of a true smart grid;
- Delineating principles Illinois should use to guide smart grid planning and deployment, for example:
 - Interoperability;
 - Open Architecture; and
 - Non-discriminatory Access;
- Developing uniform Standards;
- Establishing methods of estimating, calculating, and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs);
- Identifying the implications of smart grid technology for existing policies regarding rate design, consumer protection, and customer choice;

- Evaluating the effect of statutory renewable resource, demand response, and energy efficiency goals on smart grid planning and implementation;
- Considering the import of consumer education and dissemination of information about smart grid applications;
- Access by electricity market participants to smart grid functionalities;
- Data collection, storage, management, security, and availability to third parties;
- Standards for interconnection of third party equipment; and
- Mechanisms to flow through to customers any utility smart grid revenues.

CUB adds that a critical input into the collaborative process would be information derived through internal utility design and engineering exercises using established national models, and tools to identify functionality requirements and technical standards. Ms. Kiesling further testifies that the development of a long-term smart grid strategy should include an implementation management process, facilitated by an independent third-party technical expert, who welcomes the participation of parties beyond the utility, develops specific functionality requirements, and incorporates industry-supported interoperability standards and other architecture standards.

In order to ensure sufficient interoperability, which in turn enables information sharing, enhances the reliability and effectiveness of operational and commercial functions, and a host of additional system benefits, CUB further contends that the following Interoperability Principles must be present in any smart grid plan (as reflected in the GWAC Constitution Statements of Principle):

- Respect organizational boundaries and security across the electric system supply chain. Electric system business processes must become better automated across the value chain, while respecting privacy and each business' internal processes.
- Embrace the evolutionary dynamics of business processes, technologies, and interfaces. Over time, business processes evolve and the information system interfaces that support them are smoothly modified.
- Enable the discovery and creation of new value chains and participants. New players become active participants by accessing and delivering services through information system interfaces with other organizations.
- Enhance the resilience of the system to natural or deliberate attacks. Automation with independent, distributed decision-making schemes promotes reconfiguration of the electric grid to protect and mitigate impacts.

CUB maintains that Rider QIP is incomplete and does not require the interoperability needed to ensure that these benefits are achieved. AIU's current proposal, CUB observes, includes only four criteria for smart grid investments, instead of the more comprehensive criteria listed above and discussed in more detail by Ms. Kiesling. CUB asserts that these criteria are necessary to ensure that smart grid investments are fully beneficial to AIU, customers, and the electric grid.

5. IIEC's Position

IIEC argues that Rider QIP suffers from the various problems that beset riders generally and urges the Commission to reject it and include such capital projects in annual capital budgeting processes as they are currently. IIEC states that AIU may include within the scope of Rider QIP projects such as ordinary replacements routinely performed today. Thus, IIEC believes that it is reasonable to expect that without Rider QIP AIU would continue to invest in the types of projects envisioned under Rider QIP, on the same bases it now uses for initiating construction projects, and would seek appropriate rate base treatment in its next general rate proceedings just as it does today.

Through Rider QIP, IIEC contends that AIU is attempting to shift to its customers operating risk that is traditionally borne by the utility and addressed in a traditional rate case proceeding. AIU, however, does not view rider recovery as shifting operational risk--AIU believes it merely neutralizes the risk. IIEC agrees that risks may be neutralized from a utility's perspective, but the effect is quite different from a customer's perspective. IIEC is concerned that Rider QIP would allow AIU to avoid the quantitative assessments central to rate cases that determine whether it is reasonable and prudent to replace particular facilities. While qualifying investments might eventually get the traditional level of scrutiny before permanent inclusion in base rates, IIEC asserts that the rider procedures do not provide the same apportionment of risk achieved under traditional regulation, and do not allow close scrutiny of proposed costs until after customers are charged. Despite AIU's risk neutralization theory, IIEC maintains that the near immediate rate recovery of and on new investment undeniably constitutes a major shift in operating risk to the customer.

IIEC is also troubled by the fact that Rider QIP adjusts rates on the basis of only selected cost elements, without taking into consideration other costs or factors that would affect the utility's overall profitability. AIU fails to acknowledge that savings, along with other factors that serve to reduce the revenue requirement, e.g., changes in the depreciation reserve, may negate the need for a separate rider altogether. Another concern of IIEC's is that Rider QIP also provides additional revenue to AIU without the traditional Commission review to determine the prudence of the cost and revenue elements. IIEC contends that the ratemaking approach represented by Rider QIP bears a striking resemblance to single-issue ratemaking and, thus, should be avoided.

Rider QIP's potential to distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process worries IIEC as well. IIEC states Rider QIP may create an incentive for AIU to classify expenses in a way that maximizes rider collections, rather than foregoing recovery until its next rate case. Under Rider QIP, such choices are not transparent, and IIEC believes that they would increase the difficulty of the Commission's evaluation of AIU's costs in subsequent rate proceedings. Regulatory lag will also no longer provide an incentive to control costs in order to be more profitable to shareholders and

to diminish the need for future rate cases. The relatively immediate dollar-for-dollar recovery of eligible costs, IIEC avers, eliminates the beneficial impact of regulatory lag.

IIEC indicates that Rider QIP will also potentially create new cross-subsidies. IIEC witness Stephens testifies that if the structure of a rider is such that it collects revenues from customers on bases different from those used in recovering similar costs through base rates, or if the rider is otherwise not reflective of cost-causation, it creates a subsidy and should not be approved. In addition to the forecasted capital and O&M expenditures listed by Mr. Nelson, AIU is studying smart metering and smart grid technologies that AIU claims may provide future benefit to customers. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice. In a traditional comprehensive rate case, with appropriate cost studies, IIEC states that facilities deployed to enhance the reliability of the delivery system would likely be allocated among potential beneficiaries on the same basis as the assets made more reliable. Rider QIP does not incorporate any process to allocate costs to those who receive the direct benefit of the investment eligible for cost recovery under the rider. Therefore, of necessity there will be cost subsidies in favor of those customers that do directly benefit, according to IIEC.

An additional problem with Rider QIP identified by IIEC is that the rider seeks to recover costs that need not be incurred to meet AIU's statutory service obligations. Through Rider QIP, AIU seeks to study and invest in smart grid technologies. A smart or modernized grid is a delivery system that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically, and securely. These capabilities, IIEC argues, in addition to not being proven, are not needed to meet AIU's service obligations. To the extent that AIU's proposed smart grid projects under Rider QIP are necessary or beneficial to consumers and determined to be good, prudent projects to undertake, IIEC contends that AIU should address them as part of the normal capital budgeting process and seek recovery in its next rate case. IIEC notes that AIU began a 4-year deployment of AMR technology in May 2006 and has apparently been able to deploy this technology as part of its normal budgeting process.

IIEC opines that Rider QIP projects also could allow AIU to provide services on a competitive basis. While it is not clear exactly what functionalities ultimately will be available through a smart grid or other advanced technologies, AIU mentions in its testimony that it is conceivable that those functionalities will allow it to provide services that extend well beyond those associated with electric delivery service. IIEC indicates that there may be new business opportunities for AIU, or an unregulated affiliate, to provide value added services related to data management, energy facilities management, or even voice or data communications all underwritten through regulated rates.

From an administrative standpoint, IIEC contends that Rider QIP will require increased regulatory complexity that will be burdensome for many stakeholders. AIU has committed to paying a combined annual fee of \$100,000 for the annual filings to mitigate the burden on Commission resources. Outside of the \$100,000 pledge, AIU is short on details as to the proposed process and procedure for the Commission pre-approval. As AIU's annual \$100,000 pledge to the Commission demonstrates, IIEC states that participation in repeated regulatory proceedings before the Commission can be an expensive proposition for intervenor parties. In fact, IIEC relates that AIU does not even know if \$100,000 is sufficient to mitigate the drain on the Commission resources. Furthermore, AIU has not given consideration to paying the participation fees of other parties. No matter the level of participation, IIEC fears that the evaluation and study likely will be less than that which would typically occur in a general rate case.

6. AARP's Position

AARP objects to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. In terms of legal arguments, AARP asserts that Section 9-211 of the Act requires that the determination of any rate or charge shall include only investment that is prudently incurred and is used and useful in providing service to customers. AARP states further that Section 9-215 charges the Commission with the task of determining whether a utility's capacity is in ~~excess~~ of that reasonably necessary to provide adequate and reliable electric service." Section 8-401, AARP adds, requires Illinois public utilities to provide service and facilities in a manner that constitutes the ~~least~~ cost of meeting the utility's service obligations." AARP claims that this legal framework for ratemaking would be violated by AIU's proposal to fund projects that exceed its basic obligations through a mandatory surcharge. Rider QIP, AARP argues, is fundamentally at odds with Illinois law, especially if it were approved as an ~~empty~~ rider" with particular projects to be determined through subsequent Commission proceedings. AARP contends that such a decision would establish a ~~blank~~ check" to be filled in later—outside the full review and protections provided to consumers by a general rate case. The law requires, AARP insists, that basic electric delivery rates be limited to funding only those projects that do not exceed the least cost method of providing what is necessary for adequate and reliable electric service. AARP states further that Rider QIP violates the general rule against single-issue ratemaking.

Among the policy reasons that Rider QIP should be rejected, according to AARP, is the fact that it would inappropriately shift the responsibility and risk of capital investment between rate cases away from shareholders and onto ratepayers. If AIU believes that its expenses or costs, including the cost of financing distribution system capital additions, are increasing more rapidly than its revenues such that a revenue deficiency is being created, AARP reminds AIU that it has the option to file for a rate increase. AARP notes that AIU has not identified any prohibitions on its ability to file base rate cases to address distribution system plant additions. Currently, the risks and benefits lie with shareholders during the period between rate cases if revenues grow

more slowly or more rapidly than AIU's costs. AARP argues that Rider QIP would shift the risk of financing distribution system capital investment onto ratepayers by making ratepayers responsible for capital expenditures between rate cases. AARP observes, however, that AIU would still retain the benefit of revenue growth and expense reductions between rate cases for its shareholders. AARP contends that such a non-symmetrical ratemaking approach is extremely unfair to consumers.

A second policy reason discussed by AARP as to why Rider QIP is inappropriate is that it would remove or reduce the current incentives to prudently control the cost of plant additions. One of the useful functions of regulatory lag is to place financial responsibility upon the utility for fluctuations in costs between rate cases. AARP states that the regulatory lag feature of Rate Base/Rate of Return regulation is essential to effective and efficient operation of such a regulatory régime. In evaluating plant additions, AARP states that AIU should conduct a cost-benefit analysis to determine if there is a business case for making the expenditure and for prioritizing between competing uses of capital resources. If the case is compelling and the project is cost-justified, AARP contends that no additional rider or adjustment clause is needed. If the project is not cost-justified or the benefits are too speculative to warrant the commitment of funds, AARP suggests that it may be prudent to delay or avoid the related capital expenditures. These incentives that are currently in place would essentially be eliminated if Rider QIP were to be approved, according to AARP.

AARP's third policy argument against approval of Rider QIP is that the costs at issue are not appropriate for rider recovery. Despite AIU's claims, AARP contends that the distribution system costs that could be included in Rider QIP would not be similar to power supply costs. AARP notes AIU's acknowledgment that a rider mechanism is a more appropriate cost-recovery mechanism for costs and other rate inputs that are highly volatile, uncontrollable, and/or unpredictable. AARP contends, however, that distribution system capital investments and plant additions generally are not highly volatile, uncontrollable, and/or unpredictable. Many electric utilities have adjustment clauses to address the rate recovery of their large and volatile fuel and purchased power costs, and the primary factor typically cited in justifying the implementation of fuel and purchased power cost recovery mechanisms is that these costs are highly volatile, uncontrollable, and/or unpredictable. AARP asserts that distribution system capital additions are very different and offers the table on page 10 of AARP Ex. 1.0 to demonstrate the differences.

A fourth policy argument against Rider QIP is that it is simply not needed. AARP observes that the lack of such a rider has apparently not deterred AIU from making investments in the past which were necessary to meet its service obligations to its customers. Consequently, AARP contends that it is not appropriate to now set aside this one single issue for future recovery.

AARP's fifth argument against Rider QIP concerns Mr. Nelson's testimony that Rider QIP would facilitate investments in smart metering and smart grid technology. AARP is troubled, however, by the fact that AIU is still evaluating the benefits, costs,

and timing associated with implementing smart metering and smart grid technologies and has no firm plans in place at this time. AARP maintains that AIU should not be given the go-ahead to shift the risk of such projects that it may not otherwise construct, and which would not meet AIU's normal financial and economic analysis and capital expenditure prioritization screening, particularly when it has no definitive plan. AARP reminds the Commission that the concepts of smart grid and smart metering are not a replacement for aging infrastructure but rather an entirely new system that would be placed on top of the basic electric delivery system—the cost of which should definitely not be passed through a rider.

AIU would be better served, according to AARP, to look at other electric utilities that are implementing smart grid projects on an experimental basis without seeking advanced regulatory approval to charge the costs incurred to ratepayers. As an example, AARP points to Xcel Energy ("Xcel"), which has recently announced its plans to implement an advanced, smart grid system in Boulder, Colorado. (See AARP Exs. 2.1 and 2.2) Having established a collaborative effort with other firms and leveraging other sources including governmental grants, AARP reports that Xcel anticipates funding only a portion of the smart grid project itself. AARP adds that Xcel is not seeking permission from regulators to recover its costs in advance, but will wait until it has assessed and proven the benefits. AARP states that the approach advanced by Xcel, where the utility is assuming the initial risks of installing smart grid technology and evaluating whether it is producing benefits (consistent with the very underpinnings of rate of return regulation), stands in stark contrast with AIU's approach.

AARP's sixth policy argument against Rider QIP relates to the future project reviews before the Commission. Specifically, AARP believes that it is unlikely that it would have funding for legal and consultant participation in those subsequent proceedings or the proposed annual Rider QIP reviews. Although AIU offers to contribute money to offset the impact on Staff's resources, AARP notes that AIU made no such offer to interveners. Under the general Rider QIP process set forth in the record, AARP fears that intervener participation is likely to suffer. Consequently, AARP would prefer to see AIU's capital projects continue to be addressed in the context of general rate cases, and not be forced to consider representation in additional separate proceedings in order to provide input on rate increases outside of the protections of such general rate cases.

7. LGI's Position

LGI urges the Commission to reject Rider QIP. To begin with, LGI indicates that Rider QIP is no better than the comparable infrastructure rider recently rejected by the Commission in Docket Nos. 07-0241/07-0242 (Cons.). LGI also contends that Rider QIP violates the rule against single-issue ratemaking, since it does not consider any other impacts on costs. The rider, LGI adds, inappropriately shifts the operating risk from AIU to customers since it seeks preapproval of a project and guarantees that AIU will recover not only its costs but also a return on its investment. By granting approval between rate cases, LGI states that Rider QIP eliminates the regulatory lag for recovery

of expenses and through a yearly process it will unduly burden customers who must spend additional funds to intervene and participate in the annual approval process. LGI concurs with AG/CUB witness Brosch and Staff witness Stoller that the definitions contained in Rider QIP are far too broad and cover routine items that are typically and more appropriately considered in a traditional rate case. If implementation of a smart grid is a goal, LGI also agrees that interested parties should first collaborate on what needs/ought to be done before essentially using Rider QIP to pay for whatever AIU decides to do.

8. Kroger's Position

Kroger argues that Rider QIP should be rejected as a form of single-issue ratemaking. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, Kroger notes that the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Furthermore, Kroger maintains that the facts surrounding Rider QIP do not trigger any of the exceptions to the general prohibition against single-issue ratemaking.

As a public utility, Kroger asserts that it is AIU's responsibility to provide safe and reliable service to its customers. In meeting this responsibility, Kroger states that AIU must set budget priorities and invest sufficient capital to maintain and improve its system. The responsibility, Kroger continues, to ensure that proper investment priorities are developed and implemented rests with AIU's management. If system improvement projects are prudent investments, Kroger contends that management should fund them and seek cost recovery through conventional ratemaking treatment. Kroger does not believe that it is in the public interest to resort to single-issue ratemaking to ensure funding of necessary distribution infrastructure.

9. Commercial Group's Position

The Commercial Group indicates that its members have operations across the United States and have noticed an increase in applications by utilities for rider recovery of various costs. The Commercial Group believes that such rider recovery mechanisms shift risk of recovery of costs between rate cases from the utility to ratepayers. Therefore, it contends that riders should only be approved in extreme situations pursuant to established legal standards. According to the Commercial Group, Rider QIP does not meet these standards.

Under Rider QIP, the Commercial Group states that AIU could recover costs incurred between rate cases without a prudence or reasonable cost finding and without a corresponding cost reduction analysis. The Commercial Group considers this single-issue ratemaking that would increase rates overall. Furthermore, it adds, none of the costs in question are extraordinary or volatile in nature so as to justify rider recovery.

Instead, the Commercial Group contends that some of these investments appear discretionary in nature and might not be made by AIU if Rider QIP is not approved and could produce revenue streams from new non-essential services. Therefore, if recovery of discretionary plant costs is to be allowed that may produce non-utility revenue, the Commercial Group recommends that more administrative oversight be required to ensure that ratepayers do not overpay for utility service. The Commercial Group, however, contends that it would be administratively difficult for it to participate in the "extra" proceedings contemplated under Rider QIP. It notes that it is expensive and cumbersome enough for interveners to hire consultants and attorneys for rate cases. Expecting them to do so for additional Rider QIP proceedings is not realistic. Thus, the Commercial Group fears that intervenor input would effectively be eliminated from a significant portion of costs that by their nature require more, not less, oversight.

10. Commission Conclusion

Clearly Rider QIP has generated a great deal of controversy. While the Commission certainly does not object to the general idea of improving the electric distribution system (including implementation of smart grid technology), care must be given to ensure that it is done in a practical and cost effective manner. Cost recovery for such efforts must also be thought through. AIU proposes to recover capitalized expenditures related to system modernization and service reliability enhancements through Rider QIP. Every other party to this proceeding generally considers a rider an inappropriate way to recover such costs, for both legal and practical reasons.

The Commission has recently given the use of riders as a cost recovery mechanism a great deal of thought (see Docket Nos. 07-0241/07-0242 (Cons.)). In the proper case, riders may be used to recover certain utility costs. Typically such costs are unexpected, volatile, or fluctuating expenses, as discussed in BPI II. With regard to Rider QIP, AIU hopes to use it to recover several hundred million dollars in capital expenditures related to infrastructure improvement over a period of years. Several of the parties argue that the types of projects/expenditures that AIU seeks to pass through under Rider QIP are not unexpected, volatile, or fluctuating. IIEC contends that the long-term, planned system improvements that AIU describes (See AmerenIP Ex. 2.0E at 27-28) are the most expected, least unpredictable, and most controllable of utility costs. IIEC therefore maintains that they should receive comprehensive review and approval, not truncated examination and pre-approval under a rider.

To bolster the argument that the expenses at issue are not appropriate for rider treatment, the AG asserts that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future budgeted electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of \$157 million. Minimum spending of \$121 million (23% less) occurred in 2005 and maximum planned spending of \$181 million (15% more) is budgeted in 2008. AIU's historical actual capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006,

the AG reports that actual annual Gross Construction Expenditures, as shown on AIU's First Revised Schedule WPD-7, page 5, have ranged from \$54 to \$57 million per year for AmerenCILCO, \$45 to \$82 million for AmerenCIPS, and \$134 to \$177 million for AmerenIP.

Upon reviewing the record, the Commission is not convinced that the costs in question are appropriate for rider treatment. While AIU argues that the amounts are significant and will allow it to improve the reliability of its distribution systems, the Commission does not believe that they rise to a level necessitating rider treatment nor are they for projects whose nature warrants rider treatment. The projects/activities identified by AIU witness Nelson include, among others, pole replacement, line rebuilding, transformer purchases, inspections, and tree trimming. The costs for these types of projects and activities are typically addressed in a rate case since they are consistent with the everyday business of operating and maintaining an electricity distribution company. Some such projects may also reduce operating expenses; since there is no mechanism to pass savings on to customers, the specter of single-issue ratemaking arises as well.

Additionally, the Commission questions whether a financial need for such rider treatment exists in order to fund the projects described. AIU has offered no compelling evidence of financial need. The AG points out that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects —~~that~~ may not make the cut today.” (Tr. at 606) The Commission concurs with the AG that such testimony raises a question of whether Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses.

Even for those projects which may go beyond the customary operation and maintenance expenses, AIU has failed to persuade the Commission that Rider QIP is necessary. In fact, the Commission notes that AIU elected to deploy AMR under traditional regulation and without any rider recovery mechanism. The Commission sees no reason why other such project costs could not be recovered through a traditional rate case.

This is not to say that infrastructure costs could never be recovered through a rider. Under the proper circumstances, the Commission may be persuaded that such costs are appropriate for rider treatment. But under the facts presented here, the Commission concludes that Rider QIP is not the proper means to recover the costs in question. AIU's reliance on IAWC's Qualifying Infrastructure Plant Surcharge Rider as support for recovering general infrastructure costs through a rider is misplaced. IAWC's infrastructure rider is the result of specific legislation (Section 9-220.2 of the Act), whereas no such legislation exists for electric utility investment.

Other practical reasons exist for rejecting Rider QIP. As noted above, AIU proposes to pass expenditures related to system modernization and service reliability enhancements through Rider QIP. Plant additions associated with new customers, however, would not qualify for the rider because those projects would produce additional revenue. The problem is that it is not always easy to distinguish the type of project. Some projects may have multiple elements and it is unclear how costs would be recovered if Rider QIP were in place.

Another practical concern is the timeframe for review of proposed expenditures under Rider QIP. AIU proposes that 10 months be allowed for a docket in which Staff and any interveners could participate and weigh in on the costs and benefits of AIU's proposals. Without knowing what/how many projects AIU may seek to pass through Rider QIP, it is difficult to know whether 10 months are appropriate for such a review. Moreover, such additional dockets will increase costs to potential interveners and further drain Commission resources. AIU apparently recognizes the pressure on Commission resources since it has offered to contribute \$100,000 to cover the impact on Commission resources as a result of reviewing additional rider filings. Acceptance of this money, the Commission believes, leads to the appearance of impropriety. Furthermore, it is not clear whether AIU would attempt to recover the \$100,000 from customers, which would exacerbate the impact of Rider QIP on customers.

With regard to AIU's suggestion that smart grid costs may be recovered through Rider QIP, the Commission is even less comfortable with that idea. While the Commission believes that moving toward a smart grid is appropriate, plans to do so must be well thought out. Before the Commission will consider cost recovery for smart grid improvements, it must be confident that the improvements are practical and cost effective. At this time, it does not appear that AIU is close to having a plan for implementing a smart grid.

Among the concerns expressed about smart grid costs and Rider QIP is AARP's objection to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. AARP also fears that AIU or Ameren may generate unregulated revenue from smart grid investments paid for by customers. AARP seems to suggest that customers should share in such revenue if they are forced to pay for the system enhancements that made the revenue possible.

Another concern regarding smart grid costs and Rider QIP comes from IIEC. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice.

Such concerns of AARP, IIEC, and others all must be considered in determining how to implement and pay for smart grid technology. CUB and others recommend that the Commission direct AIU to participate in statewide smart grid workshops to essentially develop a plan for implementing smart grid technology. CUB made a similar, if not the same, proposal with respect to Rider SMP in Docket No. 07-0566. In that docket, the Commission agreed with CUB's proposal, and approved a Statewide Smart Grid Collaborative based on CUB's recommendation but with minor modifications. (See 07-0566 Order at 140-42 (Sept. 10, 2008)) The intent of the 07-0566 Order was for ~~the~~ two large investor owned utilities regulated by this Commission" to be involved in a single statewide smart grid collaborative. (Id. at 141) In addition, the 07-0566 Order includes details about the hiring of a facilitator, recovery of costs and the reports that are to be filed. It would be redundant to approve a second smart grid collaborative within this docket, therefore the Commission concurs with CUB's recommendation in this docket and directs AIU to participate in the statewide smart grid workshop, as is established in the 07-0566 Order on pages 140 to 142, under the heading ~~—Statewide Smart Grid Collaborative.~~ In that section of the Order, the Commission describes the duties, responsibilities and guidelines of the Statewide Smart Grid Collaborative, and as such, the Commission holds that section also applicable to AIU. There may have been certain issues raised in this docket that only apply to AIU; therefore, AIU, Staff, and other interested parties shall also address those in the Statewide Smart Grid Collaborative. Other relevant issues may certainly be addressed as well.

The goal of the Statewide Smart Grid Collaborative is to enable AIU to determine whether a smart grid proposal is feasible for its system and is beneficial. After the Statewide Smart Grid Collaborative is concluded, if AIU chooses to pursue the development of a smart grid, it should file its comprehensive smart grid plan – evaluating costs and benefits – with the Commission for review and approval. In Docket No. 07-0566 the Commission also set forth certain guidelines for such a filing. As the Commission did in the preceding paragraph, it sees no need to restate those guidelines herein, but instead, directs AIU to follow the process already outlined in the 07-0566 Order (under the heading ~~—Smart Grid Implementation Docket~~). Following the conclusion of the Statewide Smart Grid Collaborative, Staff shall timely submit a report to the Commission discussing the outcome of the workshops and making recommendations for further action.

A distinction between this case and the decision in the 07-0566 Order, is that the Commission is not approving a workshop process focused only on advanced meter infrastructure (~~-AMI~~). In 07-0566, ComEd was approved to install AMI in what was identified as Phase 0. Phase 0 included a workshop process to develop project goals, timelines, evaluation criteria and technology selection criteria. Such a workshop is not needed at this time for AIU, since we are not granting approval to AIU to install AMI.

Thus, the Commission agrees with CUB's recommendation for a smart grid collaborative, and directs AIU to participate in the ~~—Statewide Smart Grid Collaborative~~ established in the 07-0566 Order and abide by the guidelines outlines in the ~~—Smart Grid Implementation Docket~~ in Docket No. 07-0566. The Commission is making the above

findings so as to be consistent on this issue between the 07-0566 Order and this docket.

VIII. COST ALLOCATION METHOD

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. Each of the three utilities currently divides retail electric customers into five classes. The DS-1 tariff class contains meter, customer, and delivery charges for residential customers. The DS-2 class presents meter, customer, and delivery charges for non-residential customers with demands up to 150 kilowatt ("kW"). The DS-3 class includes meter, customer, delivery, and transformation charges for non-residential customers with demands of 150 kW-1,000 kW. The DS-4 class includes meter, customer, delivery, transformation, and reactive demand charges for customers with demands exceeding 1,000 kW. The DS-5 class presents fixture charges for lighting customers. The three utilities do not currently have uniform gas delivery classes, but have proposed revisions in this proceeding toward that goal.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a cost of service study ("COSS"). From time to time, however, circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. COSS-Based Rates vs. Across-the-Board Rate Changes

1. AIU's Position

Pursuant to Section 285.5110 of Part 285, AIU included with its rate filing a COSS for gas and electric service. AIU, however, did not follow the results of the class cost of service at equalized class rates of return in determining class revenue requirements. Rather, AIU proposes to equally apply the overall base rate percentage change on an across-the-board basis. For its gas business, AIU agrees with Staff that the across-the-board increase target should exclude Other Revenues and Special Contract Revenues.

In explaining its position, AIU first states that one must understand that rate structures often consist of a combination of both cost of service and other non-cost considerations. AIU indicates that there are numerous non-cost factors that can and do influence rate design such as rate stability and continuity, competition, customer bill impacts, and the current political environment. AIU asserts that these factors may produce rates that vary from class cost of service.

AIU states further that in Docket No. 07-0165, the Commission recognized that AIU electric customers experienced significant bill impacts in 2007 due to the major transition from frozen and reduced, bundled 1997 electric rates to post-2006 rates that included market value prices for power and energy. AIU notes this transition received much attention and resulted in new legislation to mitigate bill impacts to the DS-1 and DS-2 classes. AIU adds that approximately 80% of its gas customers are also electric customers. AIU states that the major impact of the transition in electric rates mentioned above along with the large percentage of combination accounts were major drivers in the decision to distribute the revenue changes in this case on an across-the-board basis. AIU asserts that the Commission's Order in Docket No. 07-0165 redesigned electric rates in an effort to mitigate bill impacts, and reflected a movement to a more equitable sharing of the post-2006 rate increase between the residential and the small general service rate classes. According to AIU, the Order effectively required a departure from strict cost-based rates to ~~more~~ just and more reasonable rates." Furthermore, because these electric rates have been in effect for such a short period of time (since January 1, 2008), AIU does not believe that it would be prudent to significantly alter them in this proceeding. AIU states that the circumstances are similar with the demand based rates for the DS-3 and DS-4 classes, which were adjusted by a relatively small amount in October 2007 to reflect implementation of a rate limiter, and its gas rates, which experienced price changes in December 2007.

Additionally, AIU notes that all of its customers (i.e., residential, commercial, and industrial) have seen unprecedented increases in energy bills, gasoline prices, and healthcare costs over the last several years. While rates should track costs, given due consideration to all the factors mentioned above, AIU believes that it is just and reasonable to effectuate across-the-board revenue changes by class in this case. AIU, however, reserves the option to utilize class COSS in future rate proceedings for the allocation of class revenue responsibility.

As suggested above, AIU generally seeks to maintain the existing pricing structure approved in the last delivery service proceeding, as modified by the rate redesign docket. One exception concerns the DS-1 customer, meter, and distribution delivery charges. AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust those charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. AIU understands that Staff and the AG agree with its changes on this issue. AIU, however, generally favors the standardized approach since from an incremental cost perspective, there is very little difference in customer or meter costs among the three.

For the DS-2, DS-3, and DS-4 classes, AIU proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. To the extent there are seasonal (DS-1 and DS-2) or voltage differentiated (DS-3 and DS-4) distribution delivery charges, such charges will be adjusted by a uniform percentage by utility and

by class to arrive at the targeted revenue requirement. For the DS-5 class, all fixture and delivery charges are proposed to be adjusted on an equal percentage basis to recover the targeted revenue requirement.

Although Staff expresses some concern with using uniform non-residential customer, meter, transformation, and reactive demand charges among the three utilities, AIU contends that there are numerous benefits to uniform charges. Such benefits include the reduction in oversight by customers and Alternative Retail Electric Suppliers ("ARES") operating in multiple jurisdictions; price consistency which enables consistent decisions by customers concerning transformer, substation, or capacitor bank ownership; and uniform charges reflecting the associated incremental costs. AIU also explains that by using such uniform non-residential charges, it is able to avoid a revenue deficiency that would result under Staff's proposed across-the-board increase to all rate elements. (See AIU Initial Brief at 311-312)

While IIEC does not oppose uniform customer, meter, transformation, and reactive demand charges, AIU notes that it does take issue with increasing those existing charges because it doubts that the underlying replacement cost forming the basis for the charges have increased by a similar amount. AIU explains, however, that the overall revenue recovered from customer and meter charges was tied to the overall customer and meter embedded component cost of service in the previous delivery services rate case, not a replacement cost as suggested by IIEC witness Stephens. AIU states that incremental costs were used to develop voltage differentiated meter and customer charges, and justify uniform charges, but were not used to determine how much revenue to recover from those charges. In this case, AIU says that it was assumed that if the revenue requirement was increasing by 28% for the DS-3 and DS-4 classes, the customer and meter revenue contribution should increase by a similar amount. Moreover, AIU adds, assigning no increase to the customer, meter, transformation, or reactive demand charges would require all of the increase to be assigned to the distribution delivery charge. AIU contends that it is not reasonable to assume that all of the increase in the revenue requirement assigned to a class occurred in the demand-based distribution delivery charge, while the demand-based transformation and reactive demand charges receive no increase. Regarding the transformation and reactive demand charges, AIU state that those services were priced using an incremental cost analysis in the previous delivery services rate case. AIU relates that proposed prices for both of those services are still within the cost ranges provided in the previous delivery services rate case.

With respect to the principles of cost of service rate design, AIU does not disagree with IIEC witness Chalfant's assertions that adhering to cost of service principles promotes equity, engineering efficiency, stability, and conservation. But as indicated above, AIU also recognizes that factors other than cost of service are relevant to determining class revenue requirements. AIU states that it will continue to maintain a long-term commitment to consider rates that reflect cost causation and equitable cost recovery principles as well as other methods for determining class revenue

requirements and associated rate design that AIU feels appropriate at the time to present to the Commission.

Ameren Ex. 27.1 presents a comparison of AIU's and IIEC's proposed rates. AIU submits that in all cases the residential class will receive a greater allocation of revenue responsibility under the IIEC proposal. AIU also observes that the large volume delivery service class will receive a lesser allocation of revenue responsibility under the IIEC proposal than the AIU proposal. Additionally, AIU states that one should consider that the delivery component of a residential customer's bill represents approximately 25% to 33% of the bill, while natural gas supply represents the other 67% to 75%. AIU notes that the delivery service component of a large volume non-residential customer typically represents less than 25% of the total bill with the remaining natural gas supply portion representing more than 75%. As a result, AIU states that any proposed distribution service revenue allocation has, on a total bill basis, a greater impact on residential customers and less of an impact on large volume customers. AIU concludes that IIEC's proposal for allocating greater revenue responsibility to the residential class exacerbates this condition. In response to Mr. Chalfant's claim that the future elimination of subsidies will only be more painful if additional subsidies are added in this case, AIU contends that he has not provided any evidence that supports this statement and thus it should be afforded little weight.

With regard to IIEC's recommendation concerning the use of the minimum distribution system ("MDS") concept in allocating costs, AIU agrees that it has theoretical potential, but believes that the issue of implementing MDS is not ripe at the present moment. According to IIEC witness Stowe, MDS recognizes there are delivery service costs directly attributable to electrical industry mandated safety and reliability requirements for distribution facilities, and that do not vary with customer demand. Mr. Stowe contends that those costs should not be allocated on the same basis as demand related distribution system costs. AIU finds Mr. Stowe's analysis flawed because he uses improper data to derive his recommendations. AIU contends further that his analysis unduly relies on safety and reliability concerns as the premise for immediate use of MDS calculations.

AIU asserts that proper development of an MDS-based recommendation requires the use of AIU's specific COSS data, however, Mr. Stowe elects to rely on COSS data from other electric utilities instead. In fact, AIU observes, of the five data sets used by Mr. Stowe, four are from one single conglomerate utility: the Aquila Networks. AIU argues that this choice of data sets and the assumptions made by Mr. Stowe combine to create unusable recommendations. First, AIU maintains that it is fundamentally unsound to use one utility's COSS data to set rates for another utility because each utility has its own distinct set of characteristics that determine what fixed and demand-unrelated costs it faces. AIU points out that the NARUC Electric Utility Allocation Manual ("Manual") relied upon by Mr. Stowe makes this point clear, noting:

Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the

climate, the design preferences of management, the planning for the future and the individual power companies that have merged to form the utility. (NARUC Manual at 19)

As Mr. Stowe's data shows, even within a single network, cost allocations for one account may be more than twice as high for one utility than it is for another. AIU compares the 18% demand-related share of FERC Account 366 for Aquila WPK with the 37% share of the FERC account for Aquila L&P. Across utilities from different networks, AIU asserts that variances may be absurdly incomparable – comparing the 82% demand-unrelated share of FERC Account 366 for Aquila WPK with the 6% demand-unrelated share for AmerenUE. AIU states further that the use of averages does not remedy discrepancies when such large variances are involved. At best, AIU contends that use of another, unrelated utility's COSS data might provide a generalization that helps indicate the basic contours of AIU's own cost structure. At worst, however, use of such data to pinpoint the exact division between demand-related and demand-unrelated costs for AIU results in absurdly inaccurate recommendations.

AIU's second complaint is that Mr. Stowe's assumptions are unsupported. According to AIU, Mr. Stowe assumes that his selected data sources – the four Aquila utilities and AmerenUE – represent operations similar to those within the AIU territories. The extreme variations in the data, AIU argues, belie this claim of representative consistency. As Mr. Stowe explains in rebuttal, he also assumes that safety and reliability requirements are necessarily customer-related. Specifically, he states: —“His treatment [by AIU, of FERC Accounts 364-367] assumes that the standardized safety and reliability requirements have no effect whatsoever on these costs.” (IIEC Ex. 9.0 at 2) AIU asserts that this statement is unsupported and should be disregarded. AIU acknowledges that safety and reliability requirements have an effect on costs, but it does not agree that safety and reliability requirements are necessarily customer related. Mr. Stowe continues: —“Furthermore, [AIU] incurs these costs for every additional customer it serves, and the costs are independent of customer demand and energy. Ameren recognizes this to be the case and has stated in past cases, as well as in the present case, that the MDS concept has merit.” (IIEC Ex. 9.0 at 3) Recognizing that the MDS concept has merit, AIU counters, is not the same as recognizing that costs for minimum safety and reliability standards are independent of customer demand and energy.

Third, AIU argues that the average percentages used by Mr. Stowe to classify distribution plant into customer and demand related categories are thoroughly suspect because the data sets he uses are poor proxies for AIU's cost structure. For instance, AIU states that the Colorado Aquila study took into consideration FERC Accounts 364-368; however, the study Mr. Stowe presents only includes FERC Accounts 364-367. AIU notes further that the data sets used for the Aquila studies are several years old. Finally, AIU observes that Mr. Stowe was unaware of whether the Aquila labor rates reflected in the FERC accounts were the same or different from AIU.

2. Staff's Position

Staff supports increasing existing rates on an equal percentage, across-the-board basis. Staff believes that this approach provides the most consistency with the rates developed in Docket No. 07-0165 to address bill impacts. Moreover, Staff continues, at this juncture there is no evidence to indicate that one group of AIU customers can more easily absorb a greater bill increase than another group of customers. Staff contends that the across-the-board approach appropriately recognizes that bill impacts are the overriding concern for AIU ratepayers in the current period. Furthermore, Staff asserts that it would not make sense to revise the design of AIU's electric rates since less than a year would have passed since the rate design was modified in Docket No. 07-0165. The Commission engaged in that redesign effort to mitigate the unexpected burden on customers and ensuing outrage. Staff does not believe that the concerns of AIU's customers about bill impacts have disappeared and contends that an equal percentage increase would signal to AIU's customers that the impact of higher rates will be equally distributed.

Staff expresses concern, however, that AIU diverges from the across-the-board approach by advocating uniform transformation and reactive demand charges across utilities. Staff is not persuaded by AIU's arguments that uniform charges would reduce the requisite oversight by customers and ARES operating in multiple jurisdictions or promote price consistency that would produce consistent decisions by AIU customers in Illinois concerning owning transformers, substations, and capacitor banks. Because the focus of rate design in this proceeding has been bill impacts, Staff maintains that the means to address those impacts is across-the-board increases of existing rates. Staff does not believe that it would make sense from a consistency standpoint to adopt this across-the-board approach for the large majority of charges while making exceptions for this small set of charges. Additionally, it is difficult for Staff to conceive how the specific exceptions proposed by AIU will benefit the ratemaking process.

One ratemaking proposal that Staff finds acceptable is AIU's recommendation to change the way billing demand is recorded. Currently, charges are based on maximum monthly demands for customers, regardless of when they occur. The new proposal would base maximum demands on the higher of: 1) maximum on peak demands, or 2) 50% of maximum off-peak demands. Staff finds this change reasonable because it will send price signals that encourage usage patterns that save money for AIU and all ratepayers. Staff states that the larger role played by peak demands in determining billing demands will encourage DS-3 and DS-4 customers to shift demands to the off-peak period. According to Staff, any shift in demand will relieve price pressure in the generation market during the peak period when prices should be the highest and also reduce peak period capacity constraints for the delivery system.

Because it advocates an across-the-board approach to revising AIU's rates, Staff does not discuss any concerns with the COSS submitted by AIU. Staff does, however, address the MDS proposed by IIEC. Staff understands Mr. Stowe to argue that there is a minimum cost incurred by any utility when it extends its primary and secondary

distribution system, replaces a component on those systems, or connects an additional customer to them. Staff further understands Mr. Stowe to say that the MDS approach classifies and allocates a portion of the distribution system on a customer basis. Staff notes that Mr. Stowe acknowledges that the Commission has consistently rejected the MDS in the past. Contrary to his contention that the Commission's prior experiences with MDS were heavily policy-oriented and theoretical, Staff submits that the Commission has taken a practical approach to MDS by recognizing that the MDS theoretical method of identifying the costs of connecting customers to the distribution system presents problems.

Staff also disagrees with Mr. Stowe's suggestion that the Commission has not previously considered utilities' obligation to comply with safety and reliability criteria when designing distribution systems. According to Mr. Stowe, utilities face significant costs to meet minimum safety and reliability standards for new distribution installations and these costs are clearly customer-related. In particular, Mr. Stowe cites minimum height requirements for distribution wires as well as size requirements for the wires that allow the wire to service more capacity than the customer for whom the system is being extended. Staff notes that he goes on to suggest that the cost incurred to comply with safety and reliability standards begins to outweigh the cost of meeting electrical demand. Staff considers IIEC's position unreasonable and contends that it would be presumptuous to argue that safety and reliability are new concerns for the regulatory process. Staff avers that these issues have existed since the electric industry began. Staff states further that utilities have incurred a variety of costs in the past to meet safety and reliability standards and presumably they will make significant future expenditures in these areas. Staff is not clear why Mr. Stowe considers expenditures on safety and reliability to be information that the Commission has not previously received or considered.

In addition, Staff states that it is difficult to conceive how safety and reliability are related to the number of customers on the system. The premise of the MDS system is that there are costs that pertain to connecting customers to the system, independent of the amount of demand. If the purpose of the distribution system were simply to connect customers, Staff submits that safety and reliability issues would then be a small fraction of their current levels. What creates significant safety and reliability concerns, Staff asserts, is the electricity that courses through the system.

IIEC's position is also flawed, according to Staff, because it identifies a perceived customer component for a distribution system that is clearly related to customer demands. Staff contends that IIEC's logic is comparable to arguing that costs associated with traditional customer-related components of the system, costs such as services and even meters, should be considered demand-related because a large 10 MW industrial customer would require a more costly service line and meter than a smaller customer. Nevertheless, Staff states that the costs of that service line and meter are considered customer-related because their primary purpose is to serve the individual customer. Similarly, Staff adds that the distribution system has the primary

purpose of meeting ratepayer demands and is appropriately considered demand-related.

3. AG's Position

The AG agrees with AIU that given the recent attention that the Commission has placed on rate design and cost of service issues for AIU's electric operations, it makes sense to have across-the-board increases in this case. Across-the-board increases, the AG continues, would avoid disparate bill impacts for different types of customers. AG witness Rubin states that a valid COSS is one piece of information the Commission should use in deciding each class's responsibility for any rate increase. But there is other important information that he believes the Commission also should rely on, including customer impact, the overall fairness of the result, rate continuity, gradualism, and other factors. Mr. Rubin contends that AIU's rate design and transition to fully unbundled rates has been exhaustively examined by the Commission over the past two years, and that transition process is still in progress. He maintains that it is reasonable, therefore, for the Commission to decide in this case that any rate increase or decrease should be borne by each customer class in equal proportion to the magnitude of the rate change itself.

The AG opposes IIEC's suggestion that rates be set based on a COSS that incorporates the MDS concept, either in this proceeding or any future proceeding. The AG points out that MDS affects the allocation of a significant amount of plant investment. In this case, the AG reports that IIEC's proposal will shift \$54 million in rate base from the commercial and industrial classes to the residential class. For AmerenCILCO, the shift would move more than \$16 million in rate base adjustments onto residential customers. This represents 5% of AmerenCILCO's total rate base. For AmerenCIPS, the shift would be \$13 million (almost 3% of total rate base), and for AmerenIP the shift would be \$25 million (almost 2% of total rate base).

The AG urges the Commission to reject the MDS proposal for various reasons. First, the AG states that IIEC witness Stowe makes several assumptions that are not supported by the evidence, including the submission of an alternative cost analysis that is based on hypothetical information that bears no relation to AIU's service territory. Second, the AG asserts that Mr. Stowe incorrectly assumes that the Commission's treatment of these issues has not been well informed. The AG argues that both of these assumptions are wrong. The AG relates that the Commission has consistently found that there is no customer-related component in these distribution system accounts. According to the AG, Illinois decisions rejecting MDS go back nearly 30 years, and include cases where the utility produced an MDS study that the Commission rejected. Moreover, the AG avers that the Commission's rejection of MDS has not been theoretical or based only on policy, as Mr. Stowe argues, but rather has been based on repeated findings that MDS analyses do not accurately reflect the cost of providing service to customers. (The AG references Docket Nos. 91-0335, 00-0802, and 05-0597 at page 49 of its Reply Brief.)

In response to IIEC's offer of evidence that the MDS exists, the AG states that IIEC simply relies on standards in the NESC that describe minimum standards for the construction of distribution systems. The AG also notes that Mr. Stowe did not actually conduct any analysis comparing the NESC minimum standards to AIU, but instead relied on "estimated customer and demand percentages" that he alleges are reasonable, based on studies performed for utilities in Missouri, Kansas, and Colorado. The AG asserts that the IIEC analysis is flawed in that it assumes the costs of meeting NESC minimum standards are (i) the same for utilities in different states and (ii) solely related to the number of customers served. In reality, the AG contends that the costs are based on factors completely unrelated to the number of customers served. These factors, the AG states further, are based on the assumption that customers will actually use electricity, causing the consideration of items such as the expected electricity consumption of customers; topography; population density; building type; the proximity of electrical facilities to railways, water and other natural or man-made features, etc. to be important factors.

AG witness Rubin points out that the NESC safety rules for the installation and maintenance of overhead supply lines consist of more than 120 pages and vary based on building height, use of land or water underneath the wires, etc. The AG asserts that IIEC's reliance on these standards is misguided. First, the AG argues that the different systems in Missouri, Kansas, and Colorado that IIEC relies on are not comparable to AIU's system. As an example, the AG states that in Colorado, the NESC standards require additional clearance at higher voltages because these systems are on a higher elevation than AIU's system. Second, the AG reports that there are highly disproportionate ranges for the customer related costs of each utility in the same FERC account; for instance, Account 366 ranges from 18%-94% and Account 367 ranges from 9%-79%. The AG maintains that Mr. Stowe's own data thus absolutely rebuts his testimony that it is reasonable to assume that an MDS study from one utility can be used as a proxy for another utility. Third, the AG alleges that IIEC does not establish that costs associated with satisfying NESC standards are related solely to the number of customers and not to the numerous other factors that affect the construction of distribution facilities. Fourth, the AG contends that IIEC does not establish why any minimum distribution system would be built in the absence of any electrical demand.

4. IIEC's Position

In support of its position that the COSS be used to set rates, IIEC points out that the Commission has recognized the importance of adhering to basic cost of service principles. According to IIEC, the primary reasons for using cost of service as the principal factor in revenue allocation/rate design are equity, cost-causation, appropriate price signals, conservation, and revenue stability. Cost-based rates, IIEC adds, are also essential to the development of competition.

IIEC states that the AIU electric COSS generally follow accepted cost of service principles. IIEC finds the studies to be generally sound and include many of the characteristics of a valid COSS. The studies, IIEC continues, recognize and separately

account for the multiple voltage levels at which AIU customers take service. IIEC witness Stowe, however, recommends one significant change to the AIU COSS--incorporation of the MDS concept.

With regard to the AIU gas COSS, IIEC witness Chalfant reviewed those studies and, while he disagrees with the use of the peak and average demand allocator, he does not propose any adjustment to the AIU studies, respecting use of that allocator. He concludes that the COSS demonstrate that industrial customers are subsidizing other AIU customer classes but that the use of the studies for revenue allocation and rate design purposes in these cases is sufficient to move rates toward cost. IIEC contends that the various rationales offered by AIU and Staff in support of an across-the-board approach for gas rates are not sufficient to justify abandonment of cost of service principles. IIEC asserts that AIU's reasons are basically non-cost arguments and many of them are totally unrelated to the provision of natural gas service. Those reasons include: (a) rate stability and continuity; (b) competition; (c) customer bill impact; (d) political environment; (e) AIU's electric rate increase; (f) gasoline prices; and (g) health care costs.

In response to these arguments, IIEC states that AIU has conveniently ignored the fact that rate stability and continuity and competition are enhanced by cost-based rates. Furthermore, IIEC insists that setting rates, as AIU proposes here, on the basis of what is politically correct is neither good public policy nor consistent with the other public policies and legislative priorities, such as the promotion of energy efficiency and demand response. Determining revenue allocations and setting rates on the basis of the increased cost of unrelated products and services, such as gasoline and health care is also not good public policy, according to IIEC. For example, customers who manage their electricity and gas costs through energy efficiency or demand response, possibly achieving savings as a result, may be confused to find their savings diminished by rates changed as a function of the cost of health care or some other product or service unrelated to electricity and natural gas service.

IIEC also suggests that perhaps too much emphasis is placed on rate impacts on DS-1 and DS-2 electric customers and that AIU and Staff have overlooked the fact that these customers have already been the beneficiaries of substantial rate mitigation. IIEC notes that assistance to small electric customers has come in the form of Docket No. 07-0165, Public Act 95-0481, and the Illinois Power Agency's efforts to purchase cheaper power for small customers. Large industrial customers, IIEC points out, are excluded from the benefits of the Illinois Power Agency's efforts.

While utilities normally have no financial stake in the revenue allocation method, IIEC suggests that in this proceeding AIU does; which may be influencing its endorsement of an across-the-board allocation method for electric rates. IIEC notes that AIU is proposing as a rate impact mitigation measure to cap DS-1 rates at an 8.5% increase in overall bundled rates for the first year. Recovery of any remaining allowed increase will begin in the thirteenth month following an order in this proceeding. Using AIU's proposed revenue requirement and across-the-board revenue allocation, IIEC

witness Stephens calculates that the voluntary rate cap would cost AmerenIP \$31 million. Under AIU's proposed revenue requirement and rates based on a COSS, Mr. Stephens calculates that the voluntary rate cap would cost AmerenIP \$67 million. He therefore concludes that use of the across-the-board allocation method allows AIU to recover an additional \$36 million under the voluntary rate cap.

IIEC notes that no party to this proceeding elected to present a comprehensive COSS in response to AIU's COSS. Moreover, no party, other than IIEC, offers any critique of AIU's gas or electric COSS. Other than its proposal to modify the AIU electric COSS to include the MDS concept, IIEC contends that there should be no dispute over the appropriateness of the AIU cost studies in this case for allocation of gas and electric revenue requirements and rate design.

With respect to its suggestion to incorporate MDS into the electric COSS, IIEC has provided modified versions of the COSS to reflect the central idea behind the MDS concept. That idea, according to IIEC, is that there are delivery system costs that do not vary with customer demand, but rather are customer related and attributable to electric industry mandated safety and reliability requirements. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers, it does not include costs specifically incurred to meet the peak demand of the customers. Mr. Stowe states that the latter costs are properly allocated on the basis of demand. But unless AIU's COSS are modified to reflect the MDS concept, IIEC maintains that AIU's COSS in this case tend to overstate the cost responsibility of relatively few large customers and understate the cost responsibility of the numerous small customers.

IIEC proposes that its modified versions of the AIU COSS be used for revenue allocation in this case. If, however, the Commission elects not to incorporate the MDS into the AIU electric studies in this proceeding, IIEC recommends that the Commission: (a) use the unmodified versions of the AIU studies for rate design and cost allocation purposes in this case, and (b) direct AIU to incorporate the MDS concept in its next electric delivery service rate case COSS.

In further support of the MDS, Mr. Stowe asserts that to serve customers--even small residential customers -- a utility can not install wires smaller than a certain mandated minimum size or hang wires on poles below a certain height. The applicable minimum size and height requirements are independent of the customer's maximum peak demand or energy usage. Minimum wire size and wire height are mandated by safety and reliability standards which are contained in the NESC. Under these standards, even if existing customer demand increases or decreases, Mr. Stowe testifies that the cost of meeting these NESC standards remains fixed. As an example, Mr. Stowe states that the cost of meeting code requirements for a customer with a peak demand of 3 kW is exactly the same as the cost for meeting the code requirements for a 150 kW or even a 1 MW customer. The components of the system that only just

conform to these safety and reliability standards comprise the MDS. The costs of these components represent the MDS costs. At the same time, he continues, if the system is expanded to meet additional peak demands, any costs above those associated with the minimum NESC requirements would be properly allocated on the basis of demand.

The NESC, Mr. Stowe argues, enables simple identification of MDS costs. He points out that the Commission has adopted the NESC standards (See 83 Ill. Adm. Code 305.20(b)), and Illinois utilities must comply with its mandates. The NESC specifies the minimum facilities and construction standards necessary for the safety of the public and utility employees in the installation, operation, or maintenance of electric supply and communication lines or their associated equipment. IIEC asserts that the cost of meeting these standards does not vary with the electrical demands or electrical usage of customers, but will vary based on the number of customers to be served by the electric utility.

In order to modify AIU's COSS to reflect the MDS concept in the absence of AIU specific data, Mr. Stowe used information from MDS studies of four companies which he either personally performed or reviewed during his employment with a public utility. Since the NESC standards apply equally to nearly every electric utility in the nation, Mr. Stowe concluded that it was reasonable to assume that the NESC standards are the same across utility service territories. Based upon this assumption and coupled with his experience in performing MDS studies for public utilities in other jurisdictions, he estimated applicable customer and demand percentages within the range of percentages determined by other utilities with urban operations, suburban operations, and rural operations similar to those of AIU. He also concluded that the total investment in rate base for these utilities was within the range of the total investment for AIU in this case, and that the average mix of primary and secondary distribution, as a percentage of total distribution plant, for his similar utilities was comparable to that of AIU in this case. With the use of these other four utilities' data, he determined the following demand and customer percentages: 84% demand and 16% customer for FERC Account 364 (Poles); 85% demand and 15% customer for FERC Account 365 (Overhead Wires); 39% demand and 61% customer for FERC Account 366 (Conduit); and 26% demand and 74% customer for FERC Account 367 (Underground Conductor). IIEC maintains that using Mr. Stowe's estimates of demand and customer percentages is better than making the de facto assumption that 100% of the subject costs are demand related and 0% are customer related. If the Commission concludes, however, that an Ameren-specific study is required, then IIEC suggests that AIU be directed to perform the necessary studies and present them in the next round of electric delivery service cases.

If the Commission adopts rates based on COSS, yet still has concerns about the impact on customers, IIEC proposes mitigation measures. For electric operations, IIEC offers two alternatives. Under the first alternative, rates for each class would move one-half of the way to cost of service. This approach reduces, but does not fully eliminate, rate subsidies provided or received by each class of customer. The second and final step to cost-based rates could be made in the next AIU electric delivery service rate

case or a specified period of time -- e.g., two years after rates take effect. The revenue allocations associated with such an approach for AmerenCILCO, AmerenCIPS, and AmerenIP under the original AIU COSS and IIEC's modified version of the AIU COSS are shown in IIEC Ex. 1.2. Under IIEC's second alternative for electric operations, the Commission could limit the increase to any class' distribution delivery service charges to not more than 25% above the respective utility's overall increase. For example, if AmerenIP were to be granted a 10% overall revenue increase in this case, no customer class would receive an increase greater than 35% (10% + 25%) in its distribution delivery service charges.

In the gas cases, IIEC recommends a revenue allocation that moves rates toward cost of service, but not completely to cost of service. IIEC states that revenue allocation in the gas cases was complicated by the proposed change in class structures for the gas operations of the three utilities. Because of the complications associated with changes in class structures, IIEC proposes a more moderate revenue allocation than suggested by the AIU gas operations COSS. This ensures that customers are not unreasonably impacted by the change in class definition. For AmerenCILCO, IIEC recommends a revenue allocation that still produces a decrease for GDS-1 - Residential (-4.5%), which is approximately the same as the system average decrease (-4.67%), a smaller than average decrease for Rate GDS-5 - Seasonal Delivery Service (-2%), and slightly larger than system average decreases for all of the remaining customer rate classes: GDS-4 (-11%), GDS-3 (-5.90%) and GDS-6 (-11%). For AmerenCIPS Gas, IIEC recommends a larger than average increase for GDS-1 -Residential (26.35%) and GDS-5 - Seasonal Delivery Service (26%) and a smaller than average increase for GDS-2 - Small General Service (17.15%) , GDS-3 -Intermediate General Services and GDS-4 - Large General Service (17.15%). For AmerenIP, IIEC recommends a larger than average percentage increase for GDS-1 - Residential (48%), GDS-3 - Intermediate General Service (48%), and GDS-5 - Seasonal Delivery Services (55%) and smaller than average percentage increases for GDS-2 - Small General Service (37.07%) and GDS-4 - Large General Service (37.24%).

With regard to AIU's proposal to maintain uniformity in certain charges among the three electric utilities, IIEC does not oppose uniform charges per se. IIEC observes that these charges were set on a uniform basis in AIU's last delivery service cases using a combination of embedded costs and replacement or incremental costs. IIEC reports that AIU did not supplant those charges with new cost-based charges. IIEC contends that AIU increases its costs by an escalation factor that is both illogical and unsupported in the record. The proposed charges were escalated on a ratio of the overall increase in delivery service revenues for all three AIU operating companies. According to IIEC, the overall increase ratio of 27% is a function of AIU's proposed revenue allocations and is based on increases to some cost items that have nothing to do with the customer charges, such as electric poles. The escalation factor for the customer charge results in a 27% increase. IIEC argues that there is no basis on which to conclude that the real underlying cost components of the customer charges, as determined in the last AIU delivery service rate cases, have increased by 27% in the two years between the 2004 test year in the last case, and the 2006 test year used in this case. IIEC states that a

similar concept holds true for transformation charges and reactive demand charges. In the absence of a valid cost basis for a change in the present customer, meter, transformation, and reactive demand charges, IIEC urges the Commission to retain the current charges.

5. Commercial Group's Position

The Commercial Group endorses the use of AIU's COSS, with the electric COSS modified to reflect the MDS concept. Using AIU's electric COSS, the Commercial Group determined the degree to which certain classes are currently subsidizing other classes. The following table depicts the relative rate of return for each electric class of customers for each utility. The Commercial Group submits that a relative rate of return greater than 1.0 indicates that a customer class is providing subsidies to other classes, while a relative rate of return less than 1.0 indicates that a customer class is receiving subsidies from other classes.

	AmerenCILCO	AmerenCIPS	AmerenIP
DS-1	0.82	0.62	0.26
DS-2	1.39	1.93	2.91
DS-3a	1.76	2.10	1.24
DS-3b	1.86	1.87	2.18
DS-4	0.77	0.59	1.62
DS-5	0.84	1.20	2.38

The Commercial Group argues that all AIU DS-2 and DS-3 customers are currently paying more than their respective cost of service. The Commercial Group also notes that the DS-3 class includes elementary schools while the DS-4 class includes high schools and colleges. The Commercial Group maintains that it is not fair for commercial and industrial customers, schools, and colleges to subsidize other customers.

In addition, the Commercial Group asserts that AIU has an incentive to propose an across-the-board electric rate increase in light of its voluntary rate cap proposal. Mr. Stephens, the Commercial Group states, correctly points out that AIU has a \$36 million incentive to propose an across-the-board increase. In effect, AIU's other customers are being asked to help pay for AIU's voluntary rate cap.

The Commercial Group is also under the impression that the Commission, in AIU's last rate case, directed AIU to file rates based on cost in its next rate case:

[C]ircumstances in this case lead us to believe that no customer class here should subsidize the delivery services rates of another. The

Commission directs the Ameren companies, in compliance filings, to file tariffs based on cost of service using the NCP allocation method. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 175)

The Commercial Group states that AIU filed COSS' in this case, although it did not file tariffs based on the COSS'. Mr. Baudino for the Commercial Group reviewed these studies and found them generally reliable for setting class rates.

In response to AIU's comment in its Initial Brief that it worked with the parties in an effort to address their concerns with its across-the-board proposal, the Commercial Group states that it is not sure what AIU means by this remark. The Commercial Group indicates that AIU did not approach it to discuss its concern of having to pay bills that are higher than cost. Nor does the Commercial Group understand AIU's reference in its Initial Brief to higher gasoline prices, higher energy bills, and higher health care costs as reasons for across-the-board rate increases. The Commercial Group asserts that these may be good reasons for keeping AIU's revenue increase as low as possible but not for increasing the subsidization of some classes by others.

The Commercial Group also objects to Staff's proposal for setting rates based on which customer groups can more easily absorb a greater bill increase. It is unclear to the Commercial Group how a class' relative ability to absorb rate increases could be measured in a fair, meaningful, and transparent manner. Regardless of the manner, the Commercial Group maintains that the ability to absorb rate increases (or willingness and ability to organize and advocate) is not a fair, objective way to set rates; cost is the fairest basis for setting rates.

6. Commission Conclusion

In determining whether to adopt an across-the-board rate increase or one based on AIU's COSS, the Commission notes that AIU, Staff, the AG, IIEC, and the Commercial Group have made extensive arguments both for and against the two proposals. Generally, the Commission prefers to set rates as close to the cost of service as is reasonably possible and/or appropriate. To do so, the Commission must first have an accurate idea of what the cost of serving each customer class is in each service area. AIU included with its initial rate filing COSS for its gas and electric operations. Although AIU supports an across-the-board rate increase, its COSS have been entered into the record via the granting of a June 6, 2008 IIEC motion. No party questions the validity of AIU's COSS, although IIEC and the Commercial Group would like the electric COSS to be modified to reflect the MDS concept.

IIEC and the Commercial Group express frustration with the subsidization of smaller customers by larger customers under current electric rates. While they understand the Commission's conclusions in Docket No. 07-0165 that led to the current rate structure, they do not believe that it is fair for larger customers, who are experiencing the same economic uncertainties as smaller customers, to be required to help support smaller customers. The Commission understands this frustration, but in

light of the customer impacts that led to the rate redesign in Docket No. 07-0165, finds itself in a difficult situation. Given that the rate design resulting from Docket No. 07-0165 has only been in effect since January 1, 2008, the Commission is reluctant to return to full cost based rates after less than one year. The rate shock that would result from returning to full cost based rates would likely lead to another redesign docket. In order to mitigate the impact of the rate increase approved in this proceeding and avoid renewed rate shock, the Commission believes that it is more appropriate at this time to, generally, increase rates on an across-the-board basis. The Commission certainly does not mean to suggest by this decision that cost based rates have fallen out of favor. Indeed, cost based rates, as we affirmed in our recent decision in Docket No. 07-0566, continue to be the Commission's preferred rate design methodology. That said, for purposes of this proceeding and based on this record the Commission concludes that adoption of an across-the-board increase is the most prudent and reasonable methodology that will serve to ease rate impacts occurring due to the continued transition from the end of the rate freeze.

Since the Commission is not adopting rates based on AIU's COSS, it need not address the proposal that the COSS be revised to reflect the MDS concept. Nevertheless, the Commission feels compelled to mention that using cost data from other utilities and applying that data to AIU, as IIEC does, is of little value to the Commission. As noted by AIU and other parties, significant differences exist between AIU and certain of the utilities that IIEC chose to use data from and apply to AIU. As for requiring AIU to submit COSS incorporating MDS in its next rate cases, the Commission notes AIU's objection that it not be required to do so unless the Commission intends to adopt the MDS concept in setting rates. While IIEC's discussion of the MDS concept presented some interesting ideas to consider, the Commission is not prepared to conclude here that it will implement MDS in AIU's next rate cases. Therefore, the Commission will not require ratepayers to pay the cost of preparing a COSS incorporating the MDS concept for AIU's next rate cases. This does not mean to suggest, however, that other parties should not feel free to propose COSS reflecting the MDS concept.

As noted above, AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust the DS-1 customer, meter, and distribution delivery charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. The Commission understands that Staff and the AG agree with the changes on this issue. The Commission finds AIU's proposal regarding DS-1 reasonable and approves it. In the future, however, the Commission will be interested in returning to uniform customer, meter, and distribution delivery charges among the customers of the three utilities to the extent that doing so is prudent.

For the DS-2, DS-3, and DS-4 classes, AIU also proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover

the remaining revenue requirement targeted for each class. AIU believes that this proposal will facilitate service to customers, or potential customers, taking electric service from more than one of the utilities. The Commission recognizes that there are objections to at least portions of this AIU proposal, but nevertheless finds it reasonable and agrees that it will likely facilitate service to larger customers. The Commission therefore approves this AIU proposal.

With regard to the Commercial Group's citation to page 175 of the Order in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and its discussion of cost based rates, it appears that the Commercial Group misunderstands what is meant by a compliance filing. The compliance filing in that context referred to AIU's tariffs implementing the conclusions in that Order and filed within days of the entry of that Order. The language cited by the Commercial Group was not referring to AIU's next rate cases.

B. COSS in Next Rate Cases

Staff recommends that AIU propose gas and electric rates in the next rate cases based on cost of service. AIU does not object to doing so but indicates that it may also propose rates using an across-the-board approach or some other hybrid method. AIU explains that it wishes to preserve its options in case it does not believe, under the circumstances in the next cases, that strict adherence to cost of service is appropriate. Staff agrees that there is no way of predicting the future and what conditions may exist, and understands AIU's caveat to leave its options open to an alternative rate design dependent on future conditions. IIEC and the Commercial Group support the filing of COSS in AIU's next rate cases, but add that the electric COSS should incorporate the MDS concept. LGI recommends that AIU's next rate filings include a detailed COSS showing a lighting cost of service analysis for AIU identifying lighting fixture costs as well as a detailed street light rate design study to determine cost-based lighting fixture charges. If AIU is to file new COSS in its next rate cases, Grain and Feed Association of Illinois (-GFA") would like the studies to evaluate and address the characteristics of seasonal users in general and, in particular, grain dryers. AIU objects to conducting studies incorporating GFA's proposal.

AIU is already required to provide a COSS for each utility pursuant to Part 285. The Commission anticipates that AIU will comply with this requirement and provide COSS in its next rate case filings. The Commission finds value in Staff's recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases. In considering a move towards rates based on the cost of service, AIU should take into account alternative rate structures for the all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. Market-based dynamic prices may have the overall effect of reducing the electric bills of all-electric classes of customers while at the same time ending the explicit subsidy that was designed to accomplish the same end. (See Docket No. 07-0165, Order at 25-28 (Oct. 11, 2007); see generally, Order on Rehearing (Oct. 29, 2007). In times of rapidly rising energy costs, the Commission needs to be able to

consider all options available to it to restrain rate shock while simultaneously setting rates as close as possible to cost. An analysis of the effect of dynamic market-based prices for the all-electric sub-class of residential customers would give the Commission valuable insight as to its potential benefits as the utility tries to meet those important, and some times mutually exclusive, objectives in the next rate case. In its cost of service analysis, AIU's electric utilities should develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial. Whether AIU proposes alternative rates based on some other approach is up to AIU for the reasons discussed above. However, having cost-based rates with which to compare against alternative approaches will be instructive. As noted earlier, the Commission will not be requiring AIU to incorporate the MDS concept in its next electric COSS. The Commission will, however, require AIU to analyze the cost of lighting service in each of the utility's electric service areas and develop cost-based rates for lighting fixture charges, as proposed by LGI. AIU shall also analyze the cost of serving seasonal gas users as proposed by GFA. The arguments of LGI and GFA both give the Commission reason to further consider their respective positions. AIU's rate filings, however, need not reflect adoption of the lighting and seasonal user analyses. These analyses simply need to be available for the parties and Commission to consider.

IX. RATE DESIGN/TARIFFS TERMS AND CONDITIONS

The above discussion on how to allocate costs among the classes of electric and gas customers is but one component of rate design. Rate design, in the parlance of the Commission, also encompasses the terms and conditions of service in a utility's tariffs. Over the course of this proceeding, parties raised several issues and presented arguments concerning the terms and conditions of service. Some of these issues have been resolved, while others remain contested.

A. Resolved Gas and Electric Issues

1. Budget Billing Plan Tariffs

Staff witness Harden recommended that AIU provide more specific language concerning the methodology used in its budget billing plan regarding over or under recovery of customer revenue. In response, AIU witness Jones proposed revised language that (a) reinstates the —annual settle-up” (i.e., lump-sum settlement) language in existing tariffs and (b) provides flexibility for AIU to offer a second choice to customers to smooth any annual settlement amount over the next 12 months. Ms. Harden agrees with AIU's revised language for both the gas and electric tariffs. The Commission finds the revised language appropriate and directs that it be used.

2. Refundable Deposits for Line Extensions

Staff witness Lounsberry raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Gas Service. He believed that the language could be interpreted in a manner inconsistent with 83 Ill. Adm. Code 500, "Standards of Service for Gas Utilities." In response to Staff data request ENG 2.202, AIU witness Warwick provided alternative language alleviating Mr. Lounsberry's concerns. The Commission finds the alternative language reasonable and directs that it be used.

Similarly, Staff witness Rockrohr raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Electric Service. He believed that the language could be interpreted to mean that AIU would have sole discretion to determine the period of time over which an applicant who makes a refundable deposit would qualify for a refund, which is contrary to Section 410.410. In response, AIU witness Jones provided alternative language clarifying that customers will always have a cash deposit option available. This language is acceptable to Mr. Rockrohr. The Commission concurs and directs that the alternative language be used in AIU's compliance filing.

B. Resolved Gas Issues

1. Uniform Gas Tariff Language

AIU submitted an entirely new tariff book for each of the three gas utilities. Many of the terms and condition are the same as those in the existing tariffs, but have been written/presented differently in order to make the three companies' tariffs more uniform. AIU describes the proposed changes in its Initial Brief at pages 324 through 327. Staff agrees that creating more uniform gas tariffs is desirable and recommends that the Commission approve the revisions. The Commission concurs and directs AIU to reflect the changes in its compliance filings in this proceeding.

2. Renaming of Certain Gas Customer Classes

AIU proposes to rename its gas customer classes as follows in order to conform to its electric customer classes:

AmerenCILCO

<u>Present Rate Classification</u>	<u>Proposed</u>
Rate 510 – Residential Gas Service	GDS-1
Rate 550 – Small General Gas Service	GDS-2
Rate 600 – General Gas Service	GDS-3
Rate 600 – Minimal Winter Use Gas Service	GDS-5
Rate 650 – Intermediate General Gas Service	GDS-4

Rate 700 – Large General Gas Service	GDS-6
Rate 800 – Contract Service	GDS-7

AmerenCIPS and AmerenCIPS Metro-East

<u>Present Rate Classification</u>	<u>Proposed</u>
Rate 1 – Residential Service	GDS-1
Rate 2 – General Delivery Service (small meter < 700 cubic feet per hour ("cfh"))	GDS-2
Rate 2 – General Delivery Service (large meter > 700 cfh)	GDS-3
Rate 3 – Large Use Firm Delivery Service	GDS-4
Rate 3 – Minimal Winter Use Delivery Service	GDS-5
Rate 4 – Large Use Inadequate Capacity Delivery Service	GDS-4
Rate 4 – Minimal Winter Use Delivery Service	GDS-5
Rate 5 – Special Contract Service	GDS-7

AmerenIP

<u>Present Rate Classification</u>	<u>Proposed</u>
Rate 51 – Residential Gas Service	GDS-1
Rate 63 – Small Volume Firm Gas Service	GDS-2
Rate 64 – Intermediate Volume Firm Gas Service	GDS-3
Rate 65 – Large Volume Firm Gas Service	GDS-4
Rate 66 – Seasonal Gas Service	GDS-5
Rate 76 – Transportation of Customer Owned Gas Service	GDS-1-5
Rate 90 – Contract Service	GDS-7

Staff accepts the proposed renaming of the gas customer classes as long as it does not result in unequal bill impacts on individual gas customers. The Commission finds the proposal to rename the customer classes reasonable and is aware of no unequal bill impact on any customers; therefore the renaming of the classes should be reflected in the compliance filings.

3. Customer Charges and Metering Differentials

AIU initially proposed to change all customer charges by an across-the-board percentage except the differential between the customer charges for sales customers and the customer charges for transportation customers that accounts for the added costs of daily metering. AIU's proposal also included the requirement of daily metering service and the imposition of such a differential for the first time for AmerenCILCO's Rider T customers. Staff witnesses Sackett and Harden objected to the exceptions to the across-the-board change. Mr. Sackett testified that the disproportionate changes would be a barrier to transportation customers. Ms. Harden objected because the

proposal deviates from the across-the-board change and would cause a higher level of bill impacts for transportation customers. AIU witness Warwick accepted this, removed the AmerenCILCO differential, and changed the customer charges for each Local Distribution Company (“LDC”) by the across-the-board percentage. Staff finds these changes acceptable and the Commission concurs with these changes. The resolution of this issue between AIU and Staff should be reflected in AIU's compliance filing to the extent not otherwise affected by the conclusions below.

4. Use of PGA in Cashout Mechanisms

Initially, AIU proposed to cashout daily imbalances between nominations and usage for gas transportation customers at the higher of the Chicago City gate price or the PGA and monthly imbalances at the higher of the Average Chicago City gate price or the PGA. Staff witness Sackett objected to this because the Chicago City gate price reflects the market and no other major LDCs in Illinois have the PGA in their cashout mechanism. AIU witness Glaeser removed the proposal. The current proposal is for the Chicago City gate to be the only daily cashout price. AIU has also removed its proposal for a monthly cashout. Staff agrees with this proposal. CNE-Gas supports these changes as well. The Commission finds the cashout mechanism acceptable and directs that it be reflected in the compliance filing.

5. Curtailment Language

Staff identified a drafting error regarding the proposed Curtailment Plan – wherein transportation customers were to be completely curtailed before any system supply customer. AIU addressed this error and indicates that it is not its intent to confiscate gas supply from a transportation customer and supply it to a PGA customer of the same type in the event of a system curtailment. AIU states that curtailments will take place on a customer service level and not by the type of service (Rider T or Rider S) the customer is utilizing.

Staff also recommended that AIU adopt a blend of the current AmerenCILCO and AmerenIP curtailment plans. AIU contends that doing so is not feasible. AIU witness Glaeser explained that the Curtailment Plan would only be initiated in the most severe circumstances when it is imperative that customers reduce load to enable AIU to serve the residential customers and human need providers. AIU stated that Staff's recommendation is a complicated scheme that would not be workable in an expeditious manner during a system emergency. Staff later accepted AIU's explanation.

In response to CNE-Gas' comment that AIU should only curtail deliveries within a particular customer class, without regard to whether a customer is a firm transportation or firm sales customer, AIU stated that this is exactly how the Curtailment Plan is written and intended to operate. Mr. Glaeser explained that the first category of Curtailment is —Category 1: Customers taking service under Rates GBS-4, 5, 6, and 7 except those Customers identified under Category 3” and that the curtailment language is defined by

rate category and, again, not whether the customer is taking service under Rider T or Rider S.

Staff witness Sackett objected further to AIU's proposed curtailment language because although AIU provided a rationale for four of the reasons that a Critical Day may be declared, it also added a fifth —~~can~~—all” reason. Initially, AIU had proposed to add language under Rider T to allow the declaration of a Critical Day for any —~~other~~ market condition which may warrant such action by [AIU].” Later, Mr. Glaeser offered to revise the language under the Critical Day definition to reflect the purpose of declaring a Critical Day. The Critical Day definition was revised by removing —~~market~~” prior to —~~conditions~~” and qualifying that action may only be taken due to conditions which —~~jeopardize~~ the system integrity and/or system reliability.” Staff found this change acceptable.

The Commission finds the resolution of the curtailment language issues reasonable and directs that AIU's compliance filing reflect the resolution.

6. Small Volumetric Distribution Charge

AIU recommended eliminating the Small Volumetric Distribution Charges for AmerenCILCO GDS-4 and GDS-6, and AmerenIP GDS-4. Staff witness Harden did not agree with this due to the unequal bill impacts for individual gas customers that could result from this change. AIU has agreed to maintain the Small Volumetric Distribution Charge for these rate classes. The Commission concurs that doing so is appropriate.

7. Standard Information Provided with Customer Usage History

In response to an issue raised by CNE-Gas, AIU agrees to provide with usage history requests (a) the customer's service classification and rider(s), (b) the customer's maximum daily contract quantity, (c) if applicable, the customer's bank volume, and (d) if applicable, the customer's gas main maximum allowable operating pressure. The Commission finds that doing so is reasonable and directs provisioning of this information be reflected in AIU's compliance filings.

8. Reconnect Charge

AIU witness Warwick proposes to set the gas Reconnect Charge at \$15.00 during regular working hours and at \$50.00 outside of regular working hours for each of the three utilities. The Reconnect Charge is currently \$55.00 during regular working hours and \$100 outside of regular working hours at AmerenCIPS, \$25 or actual cost at AmerenCILCO, and \$15.00 during regular working hours and \$25 outside of regular working hours for AmerenIP. Staff recommends approval of the uniform Reconnect Charge changes as a reasonable change. The Commission concurs and approves the change.

9. Dishonored Check Charge

AIU witness Warwick proposes to set the Dishonored Check Charge at \$15.00 for each of the three utilities on any negotiable instrument returned by a bank, savings institution, or other institution. The Dishonored Check Charge is currently \$15.00 at AmerenCIPS and \$10.00 at AmerenCILCO and AmerenIP. Staff recommends approval of the uniform Dishonored Check Charge change, noting that it is below the charge at many other Illinois utilities. The Commission finds the \$15.00 Dishonored Check Charge reasonable and approves of the change.

10. Footage Allowance for Service Connections

AIU witness Warwick proposes to conform all of AIU's gas tariff language regarding allowances for service connections to the language contained in the Joint Agreement of the Parties, attached as the Appendix to the Commission's Order in Docket No. 03-0767. In that proceeding, all parties reached an agreement that the free footage allowance for service connections in Illinois should be 60 feet of gas pipe. Staff witness Harden finds AIU's proposal acceptable. Consistent with its findings in Docket No. 03-0767, the Commission approves of this change.

11. Group Balancing Service for AmerenCILCO

AIU witness Glaeser explains that a key provision in the proposed services allows for Group Balancing under Rider G, which is a new service for transportation customers on the AmerenCILCO system. Group Balancing is already available to AmerenIP and AmerenCIPS transportation customers. The service provides the transportation customer and/or its marketer with an opportunity to request that its accounts be combined with two or more accounts on the same interstate pipeline for nominating and balancing purposes. Transportation customers located in a city that is served by multiple interstate pipelines, as identified on the AIU web page under Unbundled Services Management System ("USMS"), will be allowed to balance nominations across those specific multiple pipelines. Additionally, this service allows the Group Manager to manage a group of customer accounts as a single load rather than by individual accounts, and provides a netting mechanism for mitigating imbalances, wherein the daily over-deliveries for one customer can offset the under-deliveries for another customer. This offsetting arrangement aids the Group Manager in keeping daily imbalances to a minimum. The larger the marketer's customer group becomes under Group Balancing, the greater the netting effect which improves daily imbalance performance. The Commission considers the provisioning of Group Balancing for AmerenCILCO transportation customers appropriate and approves of its implementation.

12. Consolidation of PGA Rates

AIU witness Glaeser proposes that the AmerenCIPS PGA and the AmerenCIPS Metro-East PGA be consolidated into a single PGA rate. According to Mr. Glaeser,

natural gas prices have been more volatile since the winter of 2000-2001. If consolidated, he states that the AmerenCIPS Metro-East customers would be part of a larger service area and a more stable PGA rate could be provided because of expanded hedging opportunities. Mr. Glaeser explains that the AmerenCIPS strategy is to have approximately 60-75% of a normal winter's demand hedged through a combination of price hedge protection and storage withdrawals. He asserts that this strategy works well in a large system that has a large number of baseload transactions that can be efficiently price hedged. This same strategy, however, becomes constrained in a small system with limited baseload transactions where one or two hedging transactions determine the PGA for the entire winter heating season. Mr. Glaeser further testifies that if the Commission grants this proposal, AIU would be willing to work with Staff to develop a mechanism to ensure that the AmerenCIPS and AmerenCIPS Metro-East customers would be charged or credited with respect to the balance of any over- or under-recovered costs existing at the implementation date.

Based on these potential benefits to AmerenCIPS Metro-East customers, and given Mr. Glaeser's agreement to work with Staff while converting to a single PGA rate, Staff does not oppose the consolidation of the AmerenCIPS and AmerenCIPS Metro-East PGA rates into a single PGA rate. If the Commission approves AIU's proposal to consolidate the PGAs, Staff recommends that the Commission order AmerenCIPS to submit a monthly report to the Commission's Bureau of Public Utilities, for one year following the date of the order in this proceeding, estimating the PGA rates applicable to AmerenCIPS and the AmerenCIPS Metro-East territory as if no consolidation had been approved. AIU does not object to submission of monthly report as described by Staff. The Commission finds the proposals reasonable and directs that they be reflected in AmerenCIPS' compliance filing.

13. Ameren CIPS Rate 2

For AmerenCIPS and AmerenCIPS Metro-East, AIU witness Warwick proposes splitting existing Rate 2 -General Delivery Service into two new rate classes: GDS-2, for small meters (Meter A) and usage less than 700 cfh, and GDS-3, for large meters (Meter B) and usage greater than 700 cfh. Staff witness Harden does not oppose this proposal since it would not result in unequal bill impacts for individual gas customers. The Commission finds the proposal reasonable and approves it.

14. AmerenCIPS Rate 4

AIU inadvertently omitted certain tariff language it had intended to retain from the current AmerenCIPS Rate 4 – Inadequate Capacity System Gas Service. The language is currently in the existing AmerenCIPS tariff and it is appropriate to maintain the same language in the proposed tariffs related to this case. Staff supports the revision of the tariff to include the language in question. The Commission concurs with the revised language and directs that it be used.

15. AmerenIP Service Activation Fee

AIU witness Warwick proposes to eliminate the gas Service Activation Fee for AmerenIP, as neither AmerenCIPS nor AmerenCILCO have a similar provision. AmerenIP's Service Activation Fee is \$10.00 when a customer requests service under Service Classifications 51, 63, or 64. If the service activation requires lighting, relighting, or inspection of appliances, the charge is \$25.00. Since AmerenIP has not shown a need for the charge and since AIU is focusing on uniformity in the instant proceeding, Staff witness Harden agrees with AIU that elimination of the Service Activation Fee from AmerenIP's tariffs is appropriate. The Commission concurs and directs that this change be reflected in AmerenIP's compliance filing.

16. AmerenIP Rates 4 and 5

AIU witness Warwick proposed to eliminate the AmerenIP Facilities Charge presently in Rates 65 and 66. Staff witness Harden initially opposed this change and proposed that an across-the-board increase be applied to each rate without eliminating any individual rate elements, because unequal bill impacts may occur. In response, Mr. Warwick stated that this proposed revision would not result in unequal customer bill impacts. To further the argument, he presented an example calculation in which he increased the Facilities Charges by the overall percentage increase, with some rounding, and then merged the resulting charge into the proposed Customer Charges. In the example, the resulting value is the same whether the Facilities Charge is a separate charge or rolled up with the Customer Charge. Therefore, there is not an unequal bill impact. AIU contended that the resulting charge becomes more straightforward to the customer by eliminating unnecessary line item charges. AIU stated further that this is another area where it can move towards tariff conformance with no adverse customer impact. Staff agreed to merge the AmerenIP Facilities Charges for GDS-4, GDS-5, and Rider T into the applicable Customer Charges. The Commission approves of this proposal.

17. Elimination of AmerenIP's Rider H

AmerenIP proposes to eliminate its Rider H – Adjustment for Pipeline Transition Surcharge since it has not been used in several years. Staff witness Harden agrees that Rider H should be eliminated from the AmerenIP tariffs. The Commission finds this proposal reasonable and approves it.

C. Resolved Electric Issues

1. Customer and Meter Charge

AIU has a three-part residential electric rate consisting of a customer charge, a meter charge, and a distribution charge. The current customer charge and meter charge are the same among the three utilities. AIU had initially proposed to increase the customer and meter charges by 27% for all three, which is AIU's proposed system-

wide approximate average increase. Because of the impact on residential bills, the AG and Staff objected to AIU's proposal and recommended that AIU at least temporarily abandon the notion of uniform customer and meter charges. AIU now agrees and favors an approach similar to that of the AG and Staff. Pursuant to this approach, AIU will increase customer and meter charges by a level equal to the average change in residential delivery service revenue for each of the three electric utilities. The Commission finds that the AG and Staff approach is reasonable for purposes of this proceeding and approves it, however, the Commission directs AIU and Staff to review the issue of uniform customer and meter charges among the three utilities in their next electric rate cases.

2. Supply Cost Adjustments

The components that make up AIU's Supply Cost Adjustment ("SCA") are as follows: the Supply Procurement Adjustment, an Uncollectibles Adjustment, and a cash working capital adjustment. The Commission has directed AIU to update these costs and/or factors in delivery services rate case proceedings.

a. Supply Procurement Adjustment Amortization Period

AIU states that the Supply Procurement Adjustment is intended to compensate each utility for all direct and indirect costs of procuring and administering power and energy supply for all customers, other than amounts recovered in other charges to customers receiving power and energy service from AIU. According to AIU, these costs consist of expenses such as professional fees, costs of engineering, supervision, insurance, payments for injury and damage awards, taxes, licenses, and any other A&G expense not already included in the cost of power and energy service.

AIU and Staff agree that the correct ongoing costs to be recovered through the Supply Procurement Adjustment is \$1,057,003 and the amount to be amortized over the life of these rates is \$1,415,011. AIU states that it and Staff agree on the amount of the adjustment, and agree that the amortization period for the amortized portion of the costs should be consistent with the amortization period approved by the Commission in this case for electric rate case expense. AIU says the parties only disagree with whether such amortization should be based on two years or three years.

The Commission has determined the amortization period for rate case expense elsewhere in this Order. It appears that there is no other decision that the Commission must make with regard to this issue.

b. Uncollectible Adjustment

AIU witness Jones presented a chart in direct testimony showing proposed Uncollectibles Adjustment factors by rate class, which are a subset of the SCA contained within Rider PER (AIU's tariff governing prices and cost recovery for fixed price power supply service). Staff witness Ebrey objects to a portion of the calculation

proposed by AIU pertaining to write-offs for combination (both gas and electric) customers, and recommends that write-offs be allocated based on the relative gas versus electric revenues for combination customers. AIU adjusted its methodology for development of the class specific uncollectibles factors based on Ms. Ebrey's recommendation in her rebuttal testimony, and thus the issue is no longer contested. AIU states that now, only the total level of uncollectible account expense is at issue. The updated Uncollectibles Adjustment factors, taking into account the adjustment proposed by Ms. Ebrey and the total level of uncollectible account expense proposed by Mr. Stafford, are presented in AIU's Initial Brief. AIU says that if the Commission approves overall uncollectibles rates different from those provided in Mr. Stafford's rebuttal, the class level uncollectibles factors should be updated to match the approved overall uncollectibles rate.

The Commission has determined the uncollectibles issue elsewhere in this Order. AIU is directed to update the uncollectibles factors consistent with the Commission's conclusions when it makes its compliance filing at the conclusion of this proceeding. Based upon the Commission's decision to adopt AIU's three-year average for uncollectibles, the approved uncollectibles factor for AmerenCILCO is 0.582%, for AmerenCIPS is 0.569%, and for AmerenIP is 0.541% as shown on Ameren Ex. 19.4.

c. CWC Adjustment

According to AIU, the purpose of the CWC Adjustment is the equitable recovery of the time value of expenses incurred to purchase power and energy for customers in a manner that recognizes the time lag between the incurrence of these expenses and the revenue stream or receipts from customers who pay for said power and energy. AIU's proposed CWC Adjustment is 0.7986%, which has increased from 0.308%.

AIU claims the CWC associated with the power supply should be based on the calculations shown on Ameren Ex. 3.16E for each of the utilities. As discussed above in this Order, Staff witness Kahle recommends that AIU receive preferential treatment on the timing of payments from affiliated companies, in order to offset the shorter lead time in which AIU has to pay suppliers for electricity purchases, due to AIU's current credit situation. AIU argues that Mr. Kahle's position should be rejected because it conflicts with the Commission's rules designed to protect against preferential treatment between affiliated companies.

The Commission has made its decision regarding CWC elsewhere in this Order. When it makes its compliance filing at the conclusion of this proceeding, AIU is directed to make any changes to its SCA to reflect the Commission's decision regarding CWC. The Commission approves a CWC Adjustment factor of 0.7986% for use in Rider PER.

D. Contested Gas Issues

1. Gas Bank Sizing and Daily Balancing Tolerances

a. AIU's Position

In an effort to bring standardization and uniformity to gas transportation services across the three utilities, AIU has requested approval to unite all transportation services into one new rider, Rider T--Gas Transportation Service, applicable to each utility. In the process of reforming the transportation services to bring about standardization, AIU has also updated the tariffs to meet modern system goals and requirements. Central to the Rider T proposal are the policies presented with regard to banking services and imbalance tolerances designed by AIU to meet the necessities of modern operating and market conditions.

i. Policy Considerations

To understand the relevance of its banking services proposal, AIU points to the policy drivers behind the banking services and imbalance tolerance provisions, and the overall context of banking services within the Rider T framework. AIU asserts that the need for modified banking services and tolerance levels is driven by:

- Gas price volatility, which exacerbates the potential gaming opportunities and unduly exposes sales customers to cost transfers;
- Pipeline tariff restrictions, which limit the gas utilities' flexibility; and
- Pipeline capacity constraints, which means there is not the means by which to access additional gas supply.

AIU asserts that extreme price volatility in the North American natural gas markets since the winter of 2000/2001 and growing interstate pipeline capacity constraints have fundamentally changed the nature of the natural gas industry. AIU contends that the flexible transportation services it currently offers were developed years ago during a period of stable gas prices and excess and unconstrained interstate pipeline capacity in the Midwest, conditions that no longer exist today. Certain of AIU's existing transportation services include monthly balancing. AIU asserts that monthly balancing was acceptable when gas prices were stable at \$2 per MMBtu for years on end, but becomes very problematic when gas prices swing up to \$1 per MMBtu from day to day and can reach \$14 per MMBtu during peak periods.

Monthly balancing, AIU continues, creates opportunities for gas suppliers to exploit short-term price swings. AIU explains that monthly balancing in volatile gas markets gives transporters and marketers an incentive to “short” (under-deliver gas supply compared to customer demand) the LDC system on days when gas prices spike to high levels and “go long” (over deliver gas supply compared to customer demand) on days when gas prices drop to low levels, while staying roughly in balance by the end of the month. AIU witness Glaeser testifies that this manner of market arbitrage raises

AIU's costs. Since the transportation customer's demand still exists while its marketer is —shorting” the system, he explains that the LDC must still meet the overall demand of the system by delivering additional gas supplies from its suppliers and withdrawing additional gas from leased and on-system storage resources. In other words, the LDC must purchase additional gas supplies at potentially higher market prices to make up for marketers —shorting” the system. This in turn, Mr. Glaeser reports, may directly impact the sales customers, since the cost of the incremental supplies and storage withdrawals are included in the PGA rates which are paid for by the sales customers and not the transportation customers or their marketers. The inverse situation is also problematic, where daily gas prices drop to low levels and a marketer will —go long” or over-deliver compared to its customer's demand which, in turn, makes less room for the LDC to acquire gas supply during low priced periods which would lower the PGA rate. This type of operational behavior is permissible under the current tariffs for AmerenCILCO and AmerenIP, which AIU contends is the fundamental reason for the proposed changes.

With regard to capacity constraints, AIU indicates that most of the interstate pipelines that it operates on are now constrained in that all or most available firm capacity is under contract with shippers and the utilization of that firm capacity has increased, especially during the summer period for gas-fired power generation. Since 1999, AIU reports that approximately 200,000 MW of gas-fired generation has been built in the U.S. which has a potential demand of 17 Bcf/day compared to the production of natural gas in the lower 48 states of 51 Bcf/day. AIU asserts that this new demand has created significant stress on interstate pipeline operations and has given greater exposure of the natural gas markets to the price volatility of the power markets. Mr. Glaeser also testifies that even in the last 18-24 months there has been a substantial increase in pipelines issuing operational flow orders ("OFO") and system protection warnings.

AIU asserts that one of the contributing factors to the current system integrity issues is the increased reliance on natural gas used for electricity production. Ameren Exhibit 30.1 graphically demonstrates the significant amount of natural gas being consumed by power generation. AIU states that gas-fired generation has the potential of creating near instantaneous peak day demands on the pipeline systems during the summer season, which directly competes for gas supply and capacity for storage injections. AIU contends that this is causing interstate pipelines to operate with tighter tolerances, which are reflected in their tariffs for services such as daily balancing, imbalance cashouts, and penalties, in addition to operational constraints such as interruptible transportation curtailments and pipelines not allowing secondary-out-of-path nominations. AIU states that the demand for natural gas by the power generation sector has become a major source of demand for the gas industry and has created significant competition for natural gas during the summer when gas supply and pipeline capacity for storage injections are critical. In other words, the gas industry has been transformed from a winter peaking industry to a winter and summer peaking industry which has contributed to increased price volatility and constrained pipeline capacity. AIU reports that its own experience with gas generation supports this contention.

Ameren Ex. 30.3 is a graph of AmerenUE's gas generation demand since 2004 which has shown sharply increasing gas demand each year, which even outstripped the utility's internal budget forecasts. In 2004, AmerenUE's gas generation demand was 758,000 MMBtu which by 2007 had risen to 10,494,000 MMBtu or by 1,400%.

AIU submits its transportation tariffs have not changed or adapted to the new operating environment. To eliminate or at least reduce the possibility of marketers exploiting existing balancing services, AIU's proposed transportation tariffs have been designed to maintain tighter system operations in order to protect system integrity and mitigate the impact of gas price volatility on the sales customers. Of AIU's 817,000 total customers, all but 518 are system sales customers. The 518 transportation customers, however, represent a significant level of system throughput. In addition, this is the first real opportunity for AIU to update transportation services to meet the challenges of today's natural gas markets and to develop common transportation services since the acquisition of CILCO in 2003 and IP in late 2004.

To manage such tight interstate pipeline tolerances, AIU contracts for and maintains a portfolio of resources on the interstate pipelines. These resources include services offered by the interstate pipelines such as no-notice storage service, park and loan service, line pack service and park/unpark service, point operator agreements, and operational balancing agreements. These services effectively provide AIU with additional balancing flexibility and banking ability to operate within very tight tolerances. AIU points out that sales customers pay for these services.

Staff witness Sackett disputes AIU's position that interstate pipelines are operating with tighter tolerances since 1999 (when a significant amount of gas-fired generation was built in the U.S.); he further states that AIU has not provided any evidence of tightening pipeline tolerances. In response, AIU states that its actual position is that the operations of interstate pipelines have tightened and become more constrained, not necessarily that their stated tariff tolerance percentages have been reduced over time. AIU relates that many of the interstate pipelines that it utilizes to transport gas are operating at higher capacity levels on a year-round basis, not only due to gas-fired generation demand but also due to regional gas price differentials. AIU reports that mid-continent supplied interstate pipelines like Panhandle and Natural Gas Pipeline Company of America's Amarillo mainline system are sold out of firm capacity since they are connected to some of the least expensive gas production basins in the U.S.

AIU also relays that interstate pipelines are invoking operational restraints more frequently. According to Ameren Exhibit 30.4, there has been an increase in the frequency of interstate pipeline notices calling for specific actions to be taken by shippers on the pipeline systems due to operating constraints. This exhibit reflects a summary of interstate pipeline notifications/alerts during 2007 and January 2008 for critical and non-critical days, force majeure events, line segments being at capacity with Interruptible Transportation/Authorized Over-Run restricted, secondary out-of-path firm at scheduling risk, and line segments being out of service for maintenance.

These notifications/alerts have affected AIU's gas flows on interstate pipelines. Ameren Exhibit 30.5 contains a list of each date during 2007 that a supplier's gas failed to be delivered to the AIU city gate and the reasons why the deliveries were not made. One of the biggest supply interruption events during 2007 was the Panhandle mainline #400 rupture that occurred on November 21. As a result of the rupture, AIU reports that it experienced pro rata force majeure cuts to virtually all of the firm gas supplies being delivered by Panhandle. These cuts in gas supply ranged between 15%-20% of nominated volumes on Panhandle beginning on November 27, 2007 and lasting through January 8, 2008. During this time, AIU states that it was able to maintain the integrity of the system by utilizing its leased no-notice storage and on-system storage resources.

AIU reports that the Panhandle mainline rupture did not cause widespread cuts to the gas supply of transportation customers. In response to Data Request Ameren-CNE-2.06, AIU relates that CNE-Gas states that —between 11/26/07 and 1/8/08, CNE-Gas nominations to an Ameren LDC city gate supplied from Panhandle Eastern Pipe Line were cut due to a supplier force majeure.” CNE-Gas notes, however, that —[d]uring this period, CNE-Gas made no special requests to customers to reduce usage” and that —[d]uring this period, there was no specific impact” to its customers. Similarly, in its response to Ameren's Data Request Question No. 1.04, AIU states that IIEC indicates that three of its member companies received service from Panhandle and only one had gas supplies cut off or scheduled off by the pipeline and none of the three had their supply deliveries affected at their facilities. AIU contends that these transportation customers were able to maintain normal usage levels despite the Panhandle rupture because AIU back-stopped the shortage in gas supplies for the transportation customers, similar to the six examples previously discussed (and detailed in Ameren Ex. 30.6), by utilizing system supply resources which, again, are paid for by system sales customers.

AIU states that neither Staff nor CNE-Gas has a sufficient response to its evidence of additional operational restrictions, notifications, and alerts on the interstate pipelines. AIU contends that Mr. Sackett gives no consideration to the factual evidence provided in this proceeding. Subsequently, in response to Staff data request POL 13.11, AIU provided four years of historical data for three of its largest interstate pipelines, which clearly demonstrate an increasing trend of pipeline critical notices numbering over a thousand. While Mr. Sackett acknowledges AIU's response to POL 13.11, AIU states that he then devotes only two sentences to this evidence by saying —Ameren responded to Staff DR Pol-13.11, in which it presented additional summary information that does show that some operational notices increased from 2004 through 2007. However, [Ameren witness Glaeser] offers in his DR that no more than half of these affected Ameren customers.” (Staff Ex. 23.0 at 16) AIU observes that Staff fails to mention that all of these notices were critical in nature and exceeded 1,000 in number. AIU contends that this is yet another example of how Staff ignores factual evidence provided by AIU and provides absolutely no evidence of its own. Similarly, CNE-Gas states that AIU has provided —no valid evidence as to whether upstream interstate pipelines are issuing OFOs and other restrictions with increasing frequency”

when questioning whether the new balancing tolerances and transportation service changes are required to protect system integrity and operations. (CNE-Gas Ex. 2.0 at 14) As with Staff, AIU asserts that CNE-Gas simply disregards the evidence provided, while at the same time providing no evidence of its own.

Staff's view that AIU has provided very limited anecdotal evidence of any gaming behavior and no quantification of any harm to sales customers is also mistaken, according to AIU. In its responses to the IIEC Data Requests 2.34, 2.35, and 2.36, which were also provided to Staff, AIU states that it provided detailed examples and in-depth discussion of six individual operating days of transportation imbalances on the system. The information encompassed three examples of transporters net shorting the system and three examples of transporters net longing the system. In each of these examples, AIU states that factual information was provided that would enable a reasonable reader to quantify the cost impact of the imbalance on the system sales customers. AIU calculates that the cost of the three long days totals \$51,361 and the cost of the three short days totals \$47,822, for a total impact of \$99,183 for the six days. AIU contends that Staff chose to ignore the physical evidence by ignoring the value of system gas which was used to manage these imbalances. Even without doing the math, AIU states that the examples clearly show that system resources were used to handle the transporter's imbalance swing and that these system resources were being paid by AIU sales customers. AIU states further that none of the parties in this case dispute the fact that transportation imbalances (longs and shorts) occur at some level every single day on each of the systems. AIU argues that accepting Staff's recommendation means it's a certainty that system resources will be used more and more by transporters at the expense of residential and small commercial sales customers.

With regard to gaming behavior, AIU provided Staff in response to Data Request POL 6.05(g) with concrete examples of two marketers that repeatedly game the systems time and time again for economic gain, including one marketer that games between utilities from weekday to weekends. AIU maintains that some marketers are basically shifting their scheduled gas deliveries on the weekends between customer accounts that are balanced daily and those that are balanced monthly, to avoid having to decrease their gas supplies flowing to the system when the customers' usage decreases substantially on Saturday and Sunday. The marketers move the gas to the monthly balanced customers rather than decreasing the deliveries because gas supplies are typically purchased on a ratable basis over Saturday-Sunday-Monday periods. If the marketer bought the gas only for one of the three days, it would have to pay a premium for the gas or acquire balancing services on the interstate pipeline. AIU observes that one marketer is doing this on the AmerenIP system by shifting gas between Rate 76 daily balanced customer accounts and Rider OT monthly balanced customer accounts. The other marketer, AIU states, actually does this shifting maneuver from daily balanced AmerenCIPS customer accounts to AmerenCILCO monthly balanced accounts.

In response to Mr. Sackett's suggestion that by eliminating the difference between the daily price and the cashout price, any arbitrage opportunity is eliminated, AIU understands the bottom line summary of Staff's arbitrage example to be that the utility's sales customers foot the bill for the arbitrage gain achieved by the transportation customers who may be intentionally either over-delivering or under-delivering gas to the LDC system. AIU agrees that arbitrage opportunities are minimized by Mr. Sackett's suggestion of having daily cashout pricing based upon daily market prices.

ii. AIU's Banking and Balancing Proposal

AmerenCIPS and AmerenCILCO currently offer banking services in the amount of 10 times the average daily peak month ("ADPM")¹¹ and AmerenIP offers 12 times maximum daily contract quantity, but only for the 87 customers served under AmerenIP Rider OT. All other AmerenIP transportation customers served under Rate 76 currently have no bank service. In its original filing, AIU proposed to eliminate the banking services currently in place for AmerenCILCO and AmerenCIPS as well as the limited banking services available to AmerenIP customers under Rider OT (by eliminating Rider OT as discussed below). Upon further consideration, however, AIU now proposes banking services for all three Illinois gas utilities in the amount of 8 times the ADPM in the prior rolling 12-month period. AIU proposes to revise the banking services for two purposes: (1) bring consistency to the terms and conditions of service among all three companies through Rider T, and (2) to facilitate the continued provision of efficient service in light of emerging economic and industry challenges and trends.

The first reason for revision is self-explanatory: it is plainly beneficial for AIU and its customer to have uniform terms and conditions for transportation service common among all three utilities. As for the second reason for revision, concerning emerging economic and industry challenges and trends, AIU relates that in order to provide service to both transportation and sales customers efficiently, it is important that it anticipate operation needs across its system. Operations of transporting customers typically do not allow them to predict with exact certainty when and how much their future maximum gas demand will be. AIU states that a "~~bank~~" is a reserve that transportation customers can tap into to avoid the undesirable financial effects of failing to keep their gas usage within defined tolerance limits. As AIU witness Glaeser explains, banks essentially allow the transportation customer to borrow gas from AIU on days that such a customer may under-schedule and end-up short on gas delivered by suppliers. Banks are used in conjunction with tolerance limits in this manner to give flexibility to transportation customers.

The reforms of its balancing tolerances is another aspect of AIU's overall effort to bring continuity to transportation service across all three companies and to update the terms and conditions of said services as modern economic and industry trends necessitate. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing with daily cashouts as well as monthly cashouts for any imbalances at the end of the month,

¹¹ ADPM is the average daily peak from the peak month in the past 12 months.

while AmerenCILCO has only monthly cashouts. AIU views the daily balancing tolerance provision as an important tariff provision because it helps to ensure that AIU can continue to meet the needs of both transportation and sales customers under terms and prices that are reasonable to both. Daily balancing is similar to monthly balancing, the difference being that the time unit upon which a cashout is based is a day rather than a month. AIU states that the actual percentage of daily tolerance allowed by AIU is important because the greater flexibility in balancing tolerances, the greater the isolation that transportation customers have from the economic effects of mismatching the gas they have scheduled for transportation and their actual usage.

AIU proposes to eliminate monthly balancing and cashouts and utilize daily balancing and cashouts alone for each gas utility. AIU believes that daily cashouts will negate the incentive for transportation customers to under- or over-deliver gas supply compared to customer demand. AIU proposes to change the daily imbalance tolerance range to +/- 15% of nomination for each gas utility (it had originally proposed +/- 10%). AIU states that this would effectively provide an operating window of 30% for transportation customers and an intra-month banking level of 4.5 days $((MDQ \times 15\% \text{ daily tolerance} \times 30 \text{ days}) / MDQ)$, where MDQ represents maximum daily quantity. AIU also contends that this will more closely align with the tolerance ranges of the LDC's upstream interstate pipelines. While CNE-Gas is correct that upstream pipeline companies do not have daily cashout, AIU asserts that they do operate with daily tolerance limits ranging from 5% - 10%, and exceeding those limits can result in penalties and other charges.

Specifically, AIU explains that the cash-out proposal is such that whenever the bank limit is maximized, any excess volumes delivered each day are cashed out at 90% of the daily Chicago City Gate price. Imbalance volumes outside of the 15% tolerance band are cashed out with over-deliveries cashed out at 90% of the daily Chicago City Gate price and under-deliveries cashed out at 110% of the daily Chicago City Gate price. Mr. Glaeser adds that in the event an OFO is declared, the daily balance tolerance and bank limits operate in the same manner, with the exception that under-deliveries between 15% and 50% of the daily confirmed nomination ("DCN") are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Over-deliveries in excess of 15% continue to be cashed out at 90% of the Chicago City Gate price. He testifies that the purpose behind these provisions is to ensure an asymmetrical cash-out structure during OFO periods, in order to discourage under-deliveries during periods of constrained system operations. In the event of a Critical Day or curtailment, Mr. Glaeser states that the daily balance tolerances are reduced to zero and all imbalance volumes that deviate from the DCN are cashed out. All over-deliveries are cashed out at 90% of the Chicago City Gate price, while under-deliveries from 0% to 50% are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Again, he states that the purpose for this particular structure was to strongly discourage under-deliveries during Critical Days to preserve system integrity.

AIU notes that Mr. Sackett supports a bank limit of 10 times the maximum daily contract quantity (MDCQ), while CNE-Gas favors banking service with a limit 14-16 times the MDCQ. CNE-Gas' proposal, however, depends on the availability and flexibility of other features of Rider T. Specifically, CNE-Gas proposes to increase the banking limits to 10-12 times a transportation customers' MDQ if the daily tolerance stays at 20%. If the daily tolerance band is lowered to 15%, CNE-Gas proposes to increase the banking limits to 11.5-13.5 times a transportation customers' MDQ. If Staff's proposal for daily cashout and banking is adopted, CNE-Gas supports a banking limit of 14-16 times a transportation customers' MDCQ.

AIU notes that these proposals dramatically increase the allowable bank limits over the levels that are currently in effect for AIU. All of the bank limit proposals advanced by CNE-Gas and Staff are based on a specific number, e.g. 10, 12, 14, or 16 times a transportation customers' MDQ or MDCQ. These terms refer to the maximum daily contract quantities defined in a transportation customer's contract and are in many cases substantially higher than a customers' actual usage.

Despite the arguments of Staff and interveners, AIU proposes to allow customers a bank limit equal to 8 times the ADPM in the prior rolling 12-month period. This bank limit will allow the customer to under- or over-schedule gas and avoid cashout when operating outside of the proposed tolerance limit of +/- 15% until the limit is either exceeded or the balance is depleted. Additionally, AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. This important addition to banking services will assist in giving greater flexibility to transportation customers and mitigate the loss of flexibility associated with the necessary lower banking limits. AIU is also willing to modify the cashout mechanism to eliminate the utilization of the PGA rate and to base cashouts, both positive and negative, on the Platt's Gas Daily -Midpoint for Chicago Citygates," which represents a market based price.

b. Staff's Position

i. Comparison of Proposals

Staff identifies five differences between Mr. Sackett's banking proposal and AIU's proposal: (1) the size of the banks, (2) the balancing tolerance, (3) the application of cashout premiums, (4) the resulting injection and withdrawal limits, and (5) access to banks on critical days. With regard to the size of the banks, Mr. Sackett proposes that the bank size be 10 times MDCQ while AIU proposes 8 times ADPM. MDCQ reflects a larger measure of the demand put on the system than ADPM and will be used by AIU in its demand charges. IIEC recommends 10 times ADPM and CNE-Gas proposes 14-16 times MDCQ, if a straight daily cashout is approved. Mr. Sackett observes that the Commission ordered Nicor to use a 28 times MDCQ limit for its banking service in Docket No. 04-0779, so he believes that including the MDCQ metric is consistent with other Commission Orders. He explains his basis for the 10 times MDCQ level as being

a compromise between the 12 times MDCQ currently available to AmerenIP Rider OT customers and the 10 times ADPM currently available for Rider T banks at AmerenCILCO and AmerenCIPS.

With respect to the balancing tolerance, Mr. Sackett maintains that the 20% band currently in place does not need to be reduced to the 15% that AIU has proposed. He argues that AIU's evidence was purely anecdotal and its calculations of detriment were grossly over-stated. Under his proposal, with the straight daily cashout, the spread between market price and the cashout value is eliminated, which he believes will remove any incentive for transporters to game the system to exploit favorable economic conditions.

Mr. Sackett asserts further that AIU characterizes its proposal to reduce its daily balancing tolerance as a necessary consequence of decreasing tolerances on the pipelines from which it receives service. He notes, however, that a historical review of the tariffs for the interstate pipelines that AIU pointed to in support of an alleged trend toward the tightening of tolerances revealed that the current tariff sheets are nearly identical to tariff sheets in place in 1995-1997. Mr. Sackett avers that there have been no significant tariff revisions with regard to imbalance penalties and cashouts in the last five years that would require any changes in AIU's tariffs. In fact, he adds, some overrun charges have even declined on NGPL since 1995.

Staff states that AIU did not respond directly to Mr. Sackett's criticisms regarding the pipeline tolerances; instead, it sidestepped that issue and attempted to make it appear that what it really meant was that there were increasing operational issues. AIU supported the operational issues argument by alleging a trend of increased OFOs caused by operating constraints. Staff responds that the increase in OFOs demonstrated by AIU do not justify decreasing the daily balancing tolerances as proposed by AIU. Mr. Sackett asserts that no other major Illinois gas utilities – Nicor, Peoples, and North Shore – have eliminated storage services for transportation customers.

Concerning cashouts, Mr. Sackett's proposal would apply the cashout mechanism to the post-bank imbalance. Thus, under his proposal, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as —damping” gas on the system. Mr. Sackett contends that AIU's proposal, which applies the cashout bandwidth to the initial imbalance before any use of the customers' bank, does treat withdrawals from the bank as the use of system gas and injections into the bank as —damping” gas on the system. In addition, he notes that AIU would treat all gas left on the system in excess of the bank limit differently than the imbalances at the other end of the bank. Under AIU's proposal, Mr. Sackett understands that excess gas is automatically cashed out at 90% regardless of the percentage of the initial imbalance. If the bank balance is insufficient to cover the initial imbalance, it would be cashed out at 110% of the market only if it was in excess of the 15% band. Under his proposal, all normal imbalances are treated symmetrically.

Mr. Sackett explains further that the tolerance band should not be applied to the customer's initial imbalance, but rather the net customer usage of system resources after the injection or withdrawal is complete. Customer usage of system gas in excess of 20% of what is available from that customer's bank should be cashed out at 110% of the market price for that day. He believes that his approach removes the incentive to arbitrage price since transportation customers would have no incentive to over- or under-deliver. Mr. Sackett asserts that the addition of gas to the bank and the withdrawal of the gas from the bank do not constitute using system gas, but gas that already belongs to the transportation customer. Injecting gas is not —damping” gas; it is using the resources approved by the tariff, according to Mr. Sackett.

Mr. Sackett testifies further that a 20% withdrawal and 20% injection limit should be in place. He asserts that this permits transportation customers to use their banks for balancing and limited physical hedging. He adds that this gives transportation customers more of the benefits that sales customers receive from storage. In general, Mr. Sackett believes that a customer should be allowed discretion in using its bank; some of the benefits from the bank are from balancing and some from storage.

If the Commission determines that standardizing the tariffs to provide for a daily cashout is appropriate, Staff argues that it should approve tariff provisions that modify the AmerenCIPS tariff design to eliminate the proposal for monthly balancing. Staff states that the current AmerenCIPS tariff has daily balancing along with a bank and offers the option of a stand-by reserve ("SBR"). This design allows for the most options for transportation customers while closing up some of the ~~flaws~~ AIU alleges are in the existing tariff.

Staff also reports that when AIU proposed its bank limit service, it included no access to the bank on a Critical Day despite the fact that all of its current banks allow for limited access. Mr. Sackett believes that the tariff should allow limited access to the bank on a Critical Day with wording similar to AmerenCIPS' existing method, if the Commission approves the retention or expansion of the SBR (total use of system gas and bank withdrawal equal to the designated SBR amount). If the Commission does not approve the retention or expansion of the SBR, Mr. Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks (50% of MDCQ).

ii. Access to Storage Assets

A central difference in the case has been Mr. Sackett's objection to the reduced access to storage assets. AIU maintains that those resources are solely required to meet the needs of its sales customers. Mr. Sackett disagrees with this for six reasons.

First, Mr. Sackett objects to AIU not providing equal access to storage resources for transportation customers by linking use of its monopoly storage resources to the purchase of a commodity. He explains that because system customers receive the benefit of the on-system storage through lower costs, if AIU eliminates or reduces the

bank for transportation customers, when a customer switches from sales to transportation service, the switch results in the customer being denied the use of utility storage assets.

Second, Mr. Sackett notes that the Commission has consistently taken the position that system assets are for the benefit of all customers. When a customer shifts from system supply to transportation service, Mr. Sackett contends that access to system assets should be retained. He asserts that transportation customers, through their fees, compensate the utility for the appropriate use of utility resources that exist to serve all customers. Mr. Sackett rejects the premise that these assets should be used to meet the needs of sales customers first and foremost.

Third, CNE-Gas argues that while —Allen claims it does not have the resources necessary to provide storage service to transportation customers, [t]he real question of equity is not whether there is enough storage available, but how to fairly allocate the storage that is available It is inappropriate to simply conclude that because a utility has fewer total volumetric amounts of storage resources than another utility that it should not have to equitably allocate the resources it does have.” (CNE-Gas Ex. 1.0 at 16-17) Both CNE-Gas and Staff point out that the ratio of owned storage assets to throughput shows that AIU has sufficient assets to share them with both customer groups. AIU objects to only looking at owned storage but Mr. Sackett notes that AIU itself made a distinction between the two when it claimed that it needed all of its owned storage assets to meet peak day demand for its sales customers and most transportation customers pay for the use of on-system storage.

Fourth, AIU also makes the argument that transportation customers can purchase these same basic services on the interstate pipelines. Mr. Sackett contends, however, that the services offered by the interstate pipelines are not a reasonable substitute for the services provided by the LDC. He argues that these services are not close substitutes to LDC services for several reasons, including the restrictive nature of AIU's tariffs. Mr. Sackett states that interstate pipeline balancing service addresses only the problem of an imbalance with the pipeline; it would not address imbalances with the LDC. Differences between deliveries from the pipeline to the LDC and the customer's usage must be addressed by a balancing service provided by the LDC itself, according to Staff.

Fifth, AIU argues that it requires all of its owned storage resources to meet peak day demand for its sales customers and that the Commission has approved this allocation in PGA proceedings. Staff asserts that Commission findings of prudence in a PGA proceeding do not demonstrate an understanding and acknowledgement that the resource allocation of AIU's peak design day excludes transportation customers. The PGA proceedings deal with cost recovery and do not include a thorough review of the allocation of storage assets between sales and transportation assets. Mr. Sackett adds that it is not clear from the demand studies that AIU has provided whether or not AIU includes transportation customers in its peak design day. AIU's witness testifies that he believed that banks' withdrawals and imbalances were a part of the —historical look”

provided by this demand study. AIU's witness also agrees that customers have a right to withdraw gas from their banks on a Critical Day until undergoing curtailment. However, since curtailment does not affect all transportation customers or transportation customers exclusively, Staff contends that AIU must be meeting some of this demand even during a curtailment. Staff asserts that Mr. Glaeser's artificial (and confusing) distinctions about exactly where this gas comes from should carry no weight with the Commission because there is no difference between the gas that flows from the storage fields and that which is flowing from line pack or other system resources.

Sixth, AIU claims it is not providing —storage” for transportation customers, although it admits it is providing banking services for transportation customers under both AmerenCILCO's and AmerenCIPS' current Rider T and AmerenIP's Rider OT. Staff states that this is a distinction without a difference. Staff explains that banking is a service whereby a transportation customer delivers more gas than it consumes. This gas, under specified circumstances, is taken by the utility and the transportation customer has specified rights to have that amount of gas returned to the transporter when its usage exceeds its deliveries from the pipeline to the utility system. Staff contends that storage fields provide flexibility to address differences between deliveries into the utility system and usage by its customers (sales and transportation). While the companies may account for transportation customers' banks as a general obligation to provide a similar amount of gas back to them, storage fields certainly facilitate this practice. Indeed, to support a reduction in transportation customers' access to storage services, Staff relates that AIU misleadingly argues that it lacks the excess storage capacity that other utilities have. According to Staff, AIU offers no proof that it can not provide Staff's recommended storage services.

iii. Gaming

Staff observes that AIU has also listed potential gaming as a major factor for many of its tariff changes. Mr. Sackett points out three reasons why AIU's argument has no merit: (1) reliance on anecdotal evidence, (2) flawed calculations of detriment to sales customers, and finally, (3) the presence of other, more focused options to address gaming if it did exist. First, Staff asserts that the anecdotal examples AIU provided fail to demonstrate gaming. Similarly, Mr. Sackett testifies that AIU failed to consider net effects of imbalances in the opposite direction. Before tariff revisions should be made to address gaming, Staff states that AIU must demonstrate that gaming exists. Staff contends that AIU has proposed dramatic changes to address a problem that it has failed to demonstrate exists.

Second, Mr. Sackett pointed out flaws in AIU's analysis of the detriment and cost to other customers. When calculating the negative impact on sales customers, he observes that AIU neglected to account for its cashout rules. Mr. Sackett contends that this omission causes a gross overestimate of the cost that the imbalances impose on sales customers. Staff submits the cashout rules protect sales customers, and as a result of the cashout rules, Mr. Sackett indicates that these imbalances might end up benefitting sales customers.

Specifically, in its analysis of over-deliveries, Staff maintains that AIU miscalculates the detriment to sales customer by using the avoided cost of the transportation customers. Staff contends that AIU fails to acknowledge that transportation customers have suffered a loss in the value of the gas that they bought at the First of the Month price regardless of whether they sell the gas at a loss that day or store the gas on AIU's system. Staff asserts that AIU incorrectly suggests that the customers avoid this loss by putting gas onto AIU's system and uses this spread multiplied by the net positive imbalance to calculate the cost to sales customers. Staff argues that it is unreasonable to calculate the dollar amount of cost to the system sales customers and to include the value of the supposed benefit to transportation customers as a cost to sales customers.

In analyzing under-deliveries to the system, Mr. Sackett testifies that AIU fails to account for the different methods by which the negative imbalances are cashed out. Some negative imbalances are cashed out at the market price plus 10%, some get 'paid' by positive imbalances during the remainder of the month, and the rest get cashed out at the end of the month. Mr. Sackett argues that AIU's calculation, which multiplies each imbalance by the full spread between the daily price and the end of month price, overstates the size of the detriment to sales customers because it ignores those other cashouts.

Third, Mr. Sackett asserts that his recommended tariff modifications are more focused and thus would better resolve the problem. He suggests that AIU's daily imbalances could be cashed out at the daily spot price. He believes that this proposal addresses the possibility of an arbitrage occurring because of a difference between the cashout price (the average of the daily prices for the month) and the market price for a particular day. Mr. Sackett states that the incentive for arbitrage could arise if the daily price were high relative to the expected average monthly price; a customer might have an incentive to arbitrage the two prices by under-delivering gas on that day. Alternatively, if the daily price is low compared to the expected average monthly price, a customer might have an incentive to arbitrage the two prices by over-delivering gas on that day. Mr. Sackett contends that his recommendation would eliminate the difference between the daily price and the cashout price, thus eliminating the arbitrage opportunity. He adds that premiums on the cashout price for imbalances greater than 20% bands would be employed to encourage accurate nominations. Customers using system gas in excess of that 20% would be cashed out at 110% of the market price for that day. Over-deliveries would roll into a bank to the extent there it is not full up to 20 percent of the excess delivery; any additional gas would be cashed out at 90% of the daily price. Finally, the order of deliveries would follow the Commission-approved tariff in AmerenCIPS' Rider T.

Staff opposes the "extra" penalties for over-deliveries during OFOs and Critical Days. Staff recommends that over-deliveries on such days be cashed out exactly the same as other deliveries. Staff contends that over-deliveries by transportation

customers will help the utility meet its supply shortcomings for sales customers on such occasions.

c. IIEC's Position

IIEC is opposed to the elimination of the current banking provisions for AmerenCILCO and AmerenCIPS and recommends the 10-day of MDQ banking allowance be applied to all three of the AIU utilities. The fact that AIU is agreeable to providing storage equal to 8 days of ADPM demonstrates, in IIEC's opinion, that AIU does not need all of its storage to serve its sales customers. IIEC contends that AIU should provide storage banks equal to 10 days of MDQ to all of its transportation customers as a matter of equity and to facilitate the broader use of its system.

IIEC notes that AIU proposed to restrict customers' ability to use even the 8-day bank. Under AIU's latest proposal, IIEC understands that customers would be required to cashout any imbalances in excess of AIU's proposed 15% tolerance limits even if the customer had sufficient gas in its bank to cover the full imbalance. Specifically, under AIU's proposal, if a customer under-delivers to the system, but has sufficient bank balances to cover that under-delivery, the customer will only be allowed to withdraw an amount of gas from his bank that is less than or equal to the 15% daily tolerance amount. If the customer has a shortfall in deliveries of 17%, the extra 2% must be cashed out. IIEC argues that AIU has not shown that imbalances cured by the use of the customer's own banked gas will have any adverse impact on the amount of costs AIU incurs to serve its sales customers. IIEC maintains that transportation customers should be allowed to cure any imbalances by adding to or withdrawing from gas in their banks whether within the tolerance limits or not. In other words, if the customer's gas supply is unavailable on a particular day, but the customer has sufficient gas in its storage bank to cover its usage, it should be able to use that banked gas to meet its needs without having to cash out usage in excess of the daily 15% tolerance.

With regard to the specific tolerance limit proposed by AIU (15%), IIEC maintains that AIU has not shown any need to tighten the tolerances currently in place for AmerenCIPS and AmerenIP. IIEC recommends maintaining the present 20% tolerance limit and the application thereof to all three companies. IIEC contends that the only evidence of any problems provided by AIU relate to its examples using six "hand picked" days when there were large imbalances on the system. In its calculations, which purport to calculate the harm to sales customers as a result of transportation customers' actions on these days, IIEC states that AIU apparently did not reflect offsetting imbalance charge payments from transportation customers in its analysis. Thus, IIEC concludes, AIU's analysis is incomplete and fails to consider that sales customers may have benefitted from the events described.

In addition, IIEC reports that AIU has incurred only minimal imbalance penalties under the current 20% tolerances for AmerenCIPS and AmerenIP, thus it is not clear what problem AIU is addressing in reducing the tolerances from 20% to 15%. IIEC contends that AIU has not provided sufficient evidence of harm to sales customers as a

result of the actions of transportation customers under its existing tariffs, so as to justify a reduction in the daily imbalance tolerances. IIEC states further that AIU (1) has not provided specific studies or investigations, (2) has not provided sufficient proof or evidence that the gaming behavior alleged in its testimony has actually occurred, and (3) has not demonstrated that the behavior of transportation customers has systematically or consistently raised costs to sales customers. Absent a clear demonstration that there is a problem with the current 20% tolerances, IIEC asserts that they should be maintained, and applied to all the companies, but only as long as a bank equal to 10 times the customer's MDQ is made available.

d. CNE-Gas' Position

CNE-Gas understands AIU to be proposing a bank limit for each gas utility based upon 8 times the ADPM. CNE-Gas also understands that the ADPM is the same methodology that is currently employed by AmerenCILCO and AmerenCIPS in determining bank size except that the number of days used is currently 10 versus the 8 proposed. CNE-Gas observes that not only is 8 days less than the current 10-day banking service, but also the use of ADPM results in less bank capacity than if based upon an MDQ or MDCQ as is used by AmerenIP and other Illinois gas utilities. CNE-Gas states that there is no quantifiable data to support 8 days per se; it is simply offered as a compromise. While some banking is better than none, CNE-Gas continues to have concerns with: (1) the size of the bank, (2) the ability to inject and withdraw gas from that bank, (3) the parameters for bank limit transfers, or imbalance trades, and (4) the 15% daily tolerance limit.

i. Access to Storage

CNE-Gas asserts that it and AIU have markedly different views regarding AIU's storage assets. CNE-Gas understands AIU's position to be that company-owned storage assets are exclusively for the benefit of sales customers and that its resources are insufficient to provide equivalent storage service to transportation customers. According to CNE-Gas, AIU posits that transportation customers should at best benefit from its storage assets only to the extent storage is needed to provide a minimum level of balancing. AIU seeks in these proceedings to reduce the balancing flexibility afforded to transportation customers. CNE-Gas, however, contends that AIU has offered no studies or formal analysis to warrant this reduction.

When AIU's storage fields were developed, virtually all of its customers were bundled sales customers. Today, CNE-Gas notes that AIU's customers have a choice of gas supplier, and the Commission has taken steps in the recent Nicor and Peoples rate case orders to ensure that customers electing to purchase gas on an unbundled basis from suppliers other than the LDC are able to obtain transportation services that include equivalent use of the utility's resources, including storage. CNE-Gas reports that the Commission previously determined that Nicor's current allocation process for firm storage that is based upon MDCQ is fair to all customers. CNE-Gas relates that Nicor determines allocations by dividing the total amount of storage by the peak day

sendout, with the result constituting the firm storage or SBR entitlement, authorized at 28 times MDCQ, for each customer including sales customers, customer select customers, and transportation customers. CNE-Gas argues that AIU can not reserve storage for sales customers alone, as AIU's storage assets are utility customer assets rather than sales or transportation customer assets. CNE-Gas states that a full share of AIU's storage assets must be made available to each firm customer class under equivalent terms and conditions of service.

CNE-Gas states further that other Illinois gas utilities provide storage not only for balancing purposes, but also storage that allows transportation customers to purchase less expensive summer gas for consumption during the winter when prices are generally higher. CNE-Gas contends that AIU faces the same environment of price volatility and constrained energy infrastructure that other Illinois gas utilities face, yet other utilities have not found it necessary to reduce transportation customer storage banks to the minimal levels proposed by AIU. Moreover, CNE-Gas continues, AIU's proposed denial of comparable storage is not only unduly discriminatory, but also would result in an unfair competitive advantage for bundled utility sales service over third party suppliers. CNE-Gas asserts that AIU's undue discrimination is illustrated by the outcome that if an AIU transportation customer elects to return to sales service, that customer would again have access to AIU storage through bundled sales. The storage assets are available to support all customers. CNE-Gas states that AIU simply elects to deny storage rights to customers that deign to purchase gas from its competitors. Ultimately, CNE-Gas fears that permitting AIU to preserve such a competitive advantage for its bundled sales service will stifle competition and reduce customer alternatives.

ii. Sufficiency of Storage Resources

CNE-Gas suggests, in evaluating AIU's argument -- that there are insufficient resources to provide larger storage banks to transportation customers -- the Commission should not ask whether there is enough storage available but how to allocate fairly the storage that is available. Even though storage resources may be limited, CNE-Gas contends that it is equitable that all utility customers share equally in those assets that do exist. CNE-Gas and Staff offered evidence comparing AIU's storage assets with those of other major Illinois utilities. Although AIU argues it has inadequate storage resources to offer more than 8-day bank limit service, CNE-Gas argues that comparisons with other Illinois utilities dispute such a claim. While differences exist between utility assets that warrant differences in the services offered by each utility, CNE-Gas maintains that the small differences in storage assets do not warrant the substantial differences between service offerings that AIU proposes compared to Peoples, North Shore, and Nicor.

On page 16 of its Initial Brief, CNE-Gas provides a table summarizing the storage assets of six Illinois gas utilities, including the three AIU LDCs. Based on total storage as a percentage of annual customer use, CNE-Gas observes that AIU has somewhat less storage available than either Peoples or Nicor. This slightly lower capacity,

however, does not justify transportation storage banks that are less than one-third of the capacity of the storage banks offered by the other utilities, according to CNE-Gas.

CNE-Gas reports that in 2006 AmerenIP, the largest of the three AIU gas utilities had annual transportation throughput of 33.5%. CNE-Gas states that in contrast, Nicor in its last rate case reported transportation gas throughput of 47.1%, and, Peoples in its recent rate case reported a volume of just over 40%. CNE-Gas contends that AIU's successful transition to unbundled competitive alternatives will not match the success of Nicor or Peoples if the Commission permits it to skew the benefits of storage access towards its bundled sales customers.

CNE-Gas urges the Commission to authorize transportation storage banks of 12 times MDCQ if daily balancing tolerance remains at 20%. If the daily balancing tolerance is reduced to 15%, CNE-Gas states that a storage bank of 13.5 times MDCQ is more reasonable. In either case, CNE-Gas notes that the AIU storage bank would still remain comparatively lower than those of other Illinois utilities.

CNE-Gas claims further that it is unnecessary to establish extreme safeguards for sales customers that are designed to remedy purely hypothetical ills, especially when they result in the allocation of excessive costs to transportation customers. CNE-Gas does not believe that AIU provided adequate evidence that a reduction in the size of transportation customer storage banks is warranted. In support of its position, CNE-Gas asserts that (1) AIU's anecdotal examples of gaming of the system or subsidization of transportation customers were discredited, (2) AIU did not establish that reduction in the size of storage banks is essential to project system integrity, (3) AIU's storage banks for transportation customers are already relatively smaller than those of other Illinois utilities, (4) storage assets are utility assets that should be equitably allocated between both sales and transportation customers, and (5) imbalances are normal operating conditions for which storage banks are a reasonable and proven means to address.

Regardless of the Commission's decision regarding storage allocation, CNE-Gas recommends that AIU be required to investigate the storage allocation methodologies of both Peoples and Nicor. The Commission, CNE-Gas continues, should order AIU to work with Staff and interested stakeholders to study the impact of utilizing these other storage allocation methodologies in order to more equitably allocate storage assets between sales and transportation customers in the future.

iii. Injection and Withdrawal Requirements

CNE-Gas states that the function of a storage bank depends not only upon the total volume of the bank, but also the ability to inject gas into the bank and withdraw gas from that bank. Unfortunately, CNE-Gas finds that AIU's proposed bank limit service makes it extremely difficult to inject or withdraw gas from storage on a planned basis when the supplier is concerned that the amount in the bank is too low or high. The design of the service allows storage injections or withdrawals only to extent that the quantity of gas remaining is within 15% of the DCN after any imbalance between actual

usage and deliveries is taken into account. As an example, CNE-Gas states that “if a supplier anticipates a customer will use 850 therms/day, but also wants to inject gas into its storage banks, if the customer has sufficient capacity in its bank, the supplier may make a nomination of 1,000 therms, hoping that 150 therms will be injected into its bank.” (CNE-Gas Initial Brief at 18) Since an imbalance invariably occurs if the customer has a 6% imbalance and actually uses 800 therms for the day, with the DCN of 1,000 therms, 150 therms would be injected into the storage bank, and the remainder would be purchased by AIU at a discount of 90% of the market price. To avoid this penalty, CNE-Gas states that the supplier's only recourse is to lower the DNC, thereby reducing the risk of selling gas to AIU at the discount, but also lowering the quantity of gas injected into storage. Id.

If the 6% imbalance occurred in the opposite direction, and the customer instead uses 900 therms rather than the 850 anticipated, with the DCN of 1,000 therms, only 100 therms are now available for injection. Since usage projections are not precise, and any unanticipated imbalances must first be accounted for, CNE-Gas contends that storage injections are haphazard at best under AIU's proposal. Over weekends and holidays, when the ability to forecast usage is even more challenging, CNE-Gas fears that actual imbalances may deviate more than even the 15% daily balancing tolerance, resulting in a storage withdrawal when an injection was planned or vice versa.

In the above examples, the customer either made a storage injection of 9% of the DCN or, when making a storage injection of 15%, also was forced to sell any excess gas at a discount. At best, the customer could make an injection of up to 15% of DCN without a penalty. The latter scenario, CNE-Gas states, assumes perfect knowledge of customer usage, which is unrealistic and would seldom, if ever, occur.

In comparison, CNE-Gas points out that Nicor permits storage injections of 200% of the MDCQ compared to AIU's proposed 15% of DCN (by definition MDCQ/MDQ is larger than DCN). Even in Peoples' recent rate case, in which additional storage injection limits were implemented, CNE-Gas reports that injections of 100% MDQ during the winter months are allowed, with somewhat tighter limits during April through October. Yet, even the more restrictive injection season limits, CNE-Gas asserts, are significantly more liberal than those of AIU. CNE-Gas states that during the injection season Peoples permits injections that equate to average daily use in the parallel month of the prior year plus 0.67% of the customers' bank.

CNE-Gas urges the Commission to reject AIU's overly restrictive injection and withdrawal limits. CNE-Gas notes that the Commission has previously stated that “[t]o the extent possible, the Commission would prefer to increase rather than reduce the flexibility of customers, whether Transportation customers or [other] customers.” (Docket No. 04-0779, Order at 131) Because AIU's proposal is based on DCN, CNE-Gas asserts that it is more limited than Peoples' or Nicor's bank system. CNE-Gas adds that AIU would further limit transportation customer flexibility by permitting storage injections and withdrawals of only 15% of the DCN before a discounted cashout sale to AIU or premium cashout purchase by AIU.

CNE-Gas recommends that the Commission require AIU to adopt injection and withdrawal limits of one times MDQ. CNE-Gas acknowledges that even this limit is more restrictive than those of Nicor and Peoples. In the alternative, if the Commission determines limits of one times MDQ are not reasonable in this case, when storage banks have sufficient capacity, CNE-Gas believes that AIU should permit storage injections up to 100% of the DCN and, once the bank is full, excess gas would be purchased by the utility at 90% of the market index price. Since, according to AIU, its storage bank capacity is limited to no more than a handful of days, CNE-Gas states that customers would be prevented from making large, ongoing injections as their storage bank capacity would max out rather quickly. Thus, customer deliveries to storage are limited to less than 15% or 20% (depending upon the daily tolerance level approved) on most days. Storage withdrawals, CNE-Gas adds, would be limited to actual daily usage; however, once the storage account has a zero balance, any purchase of gas from AIU for balancing purposes would be made at 110% of the market index price.

iv. Imbalance Tolerance

While CNE-Gas prefers AIU's current 15% daily tolerance proposal over its original 10% proposal, CNE-Gas asserts that there are several reasons that it is more appropriate for AIU to use a 20% daily cashout imbalance parameter. First, CNE-Gas states that a daily cashout already introduces a significantly new concept for AmerenCILCO customers, which currently only use a monthly cashout. Second, because AIU proposes to continue to use a monthly cashout in conjunction with a daily cashout, CNE-Gas contends that even at a 20% daily tolerance, AIU continues to capture monthly imbalance deviations through its graduated tier of premiums and discounts.

Third, CNE-Gas questions AIU's argument that it needs to reduce its daily tolerance to 15% in order to align more closely with the tolerance ranges of the LDC's upstream interstate pipelines. CNE-Gas points out that none of the pipeline tariffs under which AIU currently secures firm service has any daily cashout provision whatsoever. Under existing pipeline agreements, CNE-Gas states, AIU does not currently adhere to daily cashout of imbalances that are greater than 20%, let alone the lower tolerance level proposed. Thus, CNE-Gas concludes, there is nothing that makes AIU's proposed 15% daily cashout tolerance inherently comparable with the existing pipeline tariffs to which AIU is subject.

Fourth, CNE-Gas asserts that AIU offers no credible evidence that the current 20% daily cashout tolerance level is not adequate. AIU instead identifies existing pipeline tariff restrictions of 5% or 10% as justification for the reduction in its daily tolerance; however, CNE-Gas demonstrates that these restrictions are not directly comparable to a daily cashout tolerance as suggested by AIU. Thus, CNE-Gas argues that there is no record evidence that the current daily cashout tolerances do not offer sufficient incentive to keep transportation imbalances at reasonable levels. The situation is exacerbated, CNE-Gas continues, by AIU's proposal to retain a monthly

cashout with tighter month-end tolerance levels. In response to AIU's claims of transportation customer gaming, CNE-Gas responds that AIU's anecdotal evidence does not establish that any gaming behavior has occurred.

CNE-Gas maintains that keeping imbalances within 20% on a daily basis, and less than 10% at a monthly level, before penalties are applied, is reasonable. CNE-Gas states that AIU offers no evidence that shows that the existing 20% daily cashout tolerance must be reduced to 15% in order to (1) more closely align with upstream pipelines, (2) provide additional incentive to transportation customers to reduce imbalances than what already exist, (3) address more frequent OFOs, or (4) prevent transportation customer gaming. CNE-Gas believes that the addition of a 20% daily cashout tolerance to AmerenCILCO tariffs, in addition to the retention of a 20% daily cashout in AmerenIP and AmerenCIPS tariffs, adequately resolves certain of the problems identified by AIU. CNE-Gas asserts that it is unnecessary to also add further restrictions by lowering the percentage.

CNE-Gas is also uncertain whether AIU intends to require both daily and monthly cashouts for transportation customers. CNE-Gas supports the use of a monthly cashout in addition to a daily cashout. CNE-Gas observes that under Staff's proposed 10-day storage bank, a daily cashout alone offers less storage capacity than a dual daily and monthly cashout mechanism. CNE-Gas explains that this is due to the loss of monthly cashout and the flexibility it provides to transportation customers which allows them to accumulate volumes during the course of a month. This functionality is described by AIU witness Glaeser as the intra-month bank. To remain on par with current service levels (which Staff argues should occur under an across-the-board rate increase), CNE-Gas states that under the daily cashout proposal, the size of the storage banks must be greater than the proposed 10 times the MDCQ if service levels are to remain roughly equal. While it prefers the current monthly and daily cashout mechanism in conjunction with a storage bank, CNE-Gas adds that daily cashout alone would be an acceptable alternative if less restrictive injection and withdrawal limits are implemented and the size of the storage bank is increased to account for the elimination of monthly cashout balances.

AIU further describes what happens with daily cashout and bank limits during an OFO and Critical Day. CNE-Gas states that in both instances AIU proposes extreme measures, but since these measures first appeared in surrebuttal testimony and no detailed tariff sheets were offered in support, CNE-Gas laments that interveners had little opportunity to respond. CNE-Gas contends that AIU has provided no evidence to justify why zero Critical Day tolerance is acceptable, nor why it is reasonable to discount excess gas supply under such conditions while doubling the cashout price of purchases. On a Critical Day, CNE-Gas asserts that a primary concern is having sufficient supplies delivered on AIU's system, yet if a marketer over delivers gas, AIU wants to penalize the over deliveries as well by cashing them out at 90% of market. To avoid the substantial penalties associated with under deliveries on Critical Days, CNE-Gas states that a prudent marketer may attempt to over deliver to some degree in order to avoid the under delivery penalties, yet AIU proposes to also penalize marketers for over delivery,

even though on a Critical Day adequate gas supply is critical for system integrity. CNE-Gas argues that penalties for over delivery during an OFO or Critical Day simply fail any logic.

CNE-Gas reports further that AIU proposes to also implement a \$6.00/therm charge for unauthorized gas usage during Critical Days. CNE-Gas states that this is in addition to the premiums just discussed that are applied to cashout. CNE-Gas does not object to implementation of the unauthorized gas charge penalty per se, but does object to the cumulative unfavorable treatment of transportation customers during OFOs and on Critical Days.

e. Commission Conclusion

As noted above, AmerenCILCO and AmerenCIPS transportation customers may currently avail themselves of a 10-day ADPM bank, and AmerenIP Rider OT customers may avail themselves of a 12-day MDCQ bank. AIU proposes to apply an 8-day ADPM bank to all transportation customers of all three utilities. Staff proposes a bank size based on 10 days of MDCQ, while IIEC proposes a bank size based on 10 days of MDQ. CNE-Gas proposes varying bank sizes depending on other factors such as imbalance tolerances.

The Commission agrees that banking service is appropriate for transportation customers. The Commission also recognizes that a reasonable size for a bank is related to other issues affecting utilities and transportation customers. Therefore, the Commission will take such issues into account when establishing a bank size for the three AIU gas operations.

One factor to consider is the ease with which banking service can be implemented. Obviously, a uniform bank size among all three utilities facilitates implementation. What also facilitates implementation and use is measuring a bank size in units already in use. As discussed above, Nicor currently calculates bank size using MDCQ, as does AmerenIP under Rider OT.¹² The fact that a customer's MDCQ will generally be known well in advance facilitates banking as well. Overall, the Commission finds that measuring a bank size through a customer's MDCQ to be reasonable and consistent with prior decisions. The ADPM unit, however, has not been applied as broadly in Illinois. Moreover, under AIU's proposal of a rolling 12-month period, the ADPM would seem to change from month to month, which the Commission believes may unnecessarily hamper and/or complicate banking.

With regard to the size of the bank, the proposals vary. AIU primarily argues that resources are simply not available to offer "large" banks. AIU also expresses concerns about gaming by transportation customers. While gaming probably occurs to some extent, the Commission is not convinced by AIU's evidence that gaming is as widespread of a problem as AIU suggests, and therefore the potential for gaming need

¹² Peoples and North Shore's tariffs indicate that they calculate bank size using MDQ, which is more similar to MDCQ than ADPM.

not be considered in setting bank size and related issues. The Commission accepts, however, that AIU has less capacity for banking than Nicor, Peoples, and North Shore. In light of the conclusions below, the Commission finds that a 10-day MDCQ bank is an appropriate size. The Commission also wishes to clarify that banks do not represent gas "borrowed" from a utility, as AIU suggests. Gas in a figurative bank represents gas owned by a transportation customer.

As for access to bank gas, if the Commission does not approve the retention or expansion of the SBR service, Staff witness Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks. AmerenCILCO's current Rider T addresses access to banks and provides in part that a transportation customer on Rate 550 or 600 may access up to 50% of its MDQ while a customer on Rate 650 or 700 may access up to 50% of its MDCQ on a Critical Day. The Commission finds AmerenCILCO's current access terms acceptable with the modification that a transportation customer otherwise eligible for service under GDS-2 or GDS-3 may access up to 50% of its MDCQ on a Critical Day and one times MDCQ on normal days. For all other transportation customers, the limits for both Critical Days and normal days shall be 20% of DCN.

The appropriate daily balancing tolerance is the next issue to be resolved. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing. AIU has proposed a 15% tolerance, while Staff, IIEC, and CNE-Gas propose 20%. As noted above, the Commission recognizes AIU's resource concerns, but is not convinced that adoption of AIU's position is warranted. In consideration of the 10-day MDCQ bank size, the Commission believes that it is reasonable to adopt a 20% tolerance band. After gaining some experience with this tolerance band in conjunction with the other conclusions regarding transportation service, the Commission may revisit this issue and further revise the tolerance band (either up or down) in AIU's next gas rate cases.

With respect to cashouts following imbalances outside of the tolerance band, AmerenCIPS and AmerenIP currently employ daily cashouts as well as monthly cashouts for any imbalances at the end of the month, while AmerenCILCO has only monthly cashouts. CNE-Gas appears to want to retain both daily and monthly cashouts. AIU, Staff, and IIEC, on the other hand, recommend only daily cashouts for transportation customers. In light of concerns over whether daily telemetry is warranted for smaller transportation customers, as discussed below, the Commission is not inclined to approve daily cashouts for transportation customers that would otherwise be GDS-2 or GDS-3 sales customers. Monthly cashouts only shall be used for such smaller transportation customers. For the remaining transportation customers, daily cashouts are reasonable and approved.

The cashout mechanism should only be applied to the post-bank imbalance. In other words, when calculating an imbalance, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as "damping" gas on the system. Additionally, over-deliveries on Critical Days shall also be cashed out the same as over-deliveries on any other day. Over-deliveries by

transportation customers will help the utility meet its supply shortcomings for sales customers on Critical Days. The Commission also notes that AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. The Commission finds AIU's proposal reasonable and adopts it. AIU's proposal to implement a \$6.00/therm charge for unauthorized gas usage during Critical Days is also hereby approved. If a transportation customer's gas usage is not measured by the LDC on a daily basis, for purposes of applying any penalties connected to unauthorized use on a Critical Day, the transportation customer's daily usage should be determined by prorating the total usage during the billing period over the number of days in the billing period.

2. AmerenIP Rate 76 as a Stand-Alone Tariff

a. AIU's Position

AIU witness Warwick proposes to eliminate the existing Rate 76--Transportation of Customer-Owned Gas from AmerenIP's rate schedules as part of its effort to create a new, consistent Rider T that will implement uniform terms and conditions for transportation service across all three gas distribution company service territories. The conversion would be accomplished by increasing each of the Rate 76 components by the overall base rate percentage increase and then re-segmenting the components into the non-residential GDS rates to conform to the uniform structure common to the AmerenCILCO and AmerenCIPS tariffs. AIU believes that eliminating Rate 76 in favor of Rider T will result in a tariff layout that is easier to understand and more logically consistent, which is particularly important for those entities that have multiple facilities and/or customers in the various AIU service territories.

AIU's proposal to remove AmerenIP's Rate 76 as a stand alone tariff does not affect the proposed base service rates (i.e., Customer Charge, Demand Charge, Overrun Demand Charge) of the customers affected by this change due to the across-the-board increase proposal of AIU. AIU contends that the resulting rate values are the same whether Rate 76 is a stand alone tariff or as stated under the proposed Rider T. AIU also notes that, under its proposal, changes to Rider T's service terms and conditions are applicable to current AmerenIP Rate 76 customers under either the stand alone or merged basis.

Staff witness Sackett criticizes generally the effort to consolidate transportation rate structures into Rider T and therefore opposes the elimination of the individual company transportation riders. Staff witness Harden objects to eliminating Rate 76 out of concern that doing so may result in unequal bill impacts on customers. AIU asserts that Staff supports consistency, but only if it does not create any cost impacts for transportation customers. With the across-the-board increase to each delivery service rate component, AIU states that it is not clear or apparent what, if any, unequal bill impacts may result. AIU asserts that there is no apparent record evidence to justify Staff's position.

b. Staff's Position

Because she fears that the elimination of Rate 76 could result in unequal bill impacts, Ms. Harden opposes this change and proposes that an across-the-board increase should be applied to each rate for each customer class without making any tariff eliminations that may cause unequal bill impacts. Staff also does not believe it will be clear to customers that the resulting rate values will be the same whether Rate 76 is on a stand-alone or merged basis. In addition, Staff does not agree with AIU's contention that "in conforming tariff structures that differ across three service territories, certain provisions enjoyed by certain customers will be eliminated." (AIU Initial Brief at 330) Staff contends that AIU's choice to eliminate services and offer fewer choices to transportation customers is a deliberate one, not forced by any changing energy market requirements.

c. Commission Conclusion

The Commission does not share Staff's concerns about eliminating AmerenIP's Rate 76 as a stand alone tariff in light of the manner in which AIU proposes to do so. Specifically, it is unclear how unequal bill impacts to AmerenIP transportation customers will occur. The Commission also recognizes that AIU is not proposing to incorporate Rate 76 into Rider T as a result of changing energy markets, but rather is doing so based on its own preference. Such a motivation, however, does not alone warrant rejecting AIU's proposal. In any event, the Commission finds that its other conclusions regarding rate design will sufficiently protect transportation customers. Those who believe that additional provisions regarding transportation customers are warranted are free to raise them in AIU's next gas rate case. Intervening transportation customers and marketers have not objected to AIU's proposal.

3. Elimination of AmerenIP's Rider OT

a. AIU's Position

AIU proposes to eliminate Rider OT--Optional Transportation of Customer-Owned Gas from AmerenIP's tariff books. AIU indicates that this rider allows customers essentially to switch back and forth between system sales gas and transportation service. AIU states that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. In response to criticism from Staff witness Sackett and GFA witness Adkisson related to rate impacts from eliminating Rider OT, AIU has proposed to grandfather existing Rider OT customers within existing GDS rate classifications. The grandfathering proposal applies to the monthly rate values only; all other terms and conditions will be pursuant to the proposed Rider T provisions. AIU explains that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. The limitation grants existing Rider OT customers AIU's recommended across-the-board percentage change and, at the same time, provides a

transition mechanism consistent with Mr. Glaeser's testimony to eliminate Rider OT. AIU states that the retained Rider OT rate structures will be located within each non-residential GDS classification, GDS-2 through GDS-6. If a grandfathered customer on Rider OT elects Rider S, AmerenIP will purchase any remaining banked gas at the average market price for the year. If a grandfathered customer chooses Rider T, AIU states that the customer will have to deliver an appropriate amount of gas on a daily basis to the AmerenIP system to cover its usage.

In response to Staff's claim that Rider OT should not be eliminated because it provides a valuable service, allows for monthly balancing, contains no daily metering requirement, and provides system back-up service, AIU notes that only 87 customers are taking this service. While Staff acknowledges this is a small percentage of the total customer base, it claims that this may be an indictment of the current service offerings. AIU contends that this argument makes no sense since AmerenIP's current service offerings provide for bank services and extreme tolerance levels--both of which Staff claims are sorely needed by transportation customers. AIU also observes that Staff's proposed bank services and tolerance levels are not much different than what is currently being offered. To accept Staff's position on Rider OT, AIU continues, it follows that Staff's own proposal falls short.

b. Staff's Position

Staff witness Sackett recommends that the Commission reject AIU's proposal to eliminate AmerenIP's Rider OT. He contends that Rider OT should be retained because it provides a valuable service to transportation customers by giving customers an option between a service designed for large customers (Rider T) and one that allows for monthly balancing, no daily metering requirement, and system back up, all of which are ideal for smaller customers (Rider OT). In the previous gas rate case, Docket No. 04-0476, he notes that the Commission accepted AmerenIP's proposal to eliminate the banks for Rate 76 in part based upon AmerenIP's argument that those services were available under Rider OT. He believes that that policy goal of maintaining a banking storage service option for transportation customers is as important now as it was when the Commission entered its Order in Docket No. 04-0476. Indeed, Mr. Sackett continues, it may be more important now; without Rider OT, all customers, regardless of size, are forced onto the proposed Rider T.

Contrary to AIU's assertion, Mr. Sackett argues further that the services under Rider OT are valuable to transportation customers. He maintains that the fact that 87 AmerenIP customers currently pay for the services demonstrates that Rider OT is valuable. While 87 customers represents a small percentage of the total customer base for which the service is available, Mr. Sackett contends that this may be more of an indictment of AIU's current service offerings than an indication that a particular service has no value. He fears that AIU's current transportation service will become even less attractive if AIU's proposed reductions in services are approved. Mr. Sackett recommends that the Commission focus on the level of service that transportation customers receive and how much it costs. If the Commission adopts his proposals, he

asserts that AIU's transportation service will become a better value, and it is likely that more customers will switch to transportation service.

Staff also notes that AIU's primary objection to Rider OT is that it —~~allows~~ customers essentially to switch back and forth between system sales gas and transportation service" (Ameren Ex. 16.0 at 40) Staff notes further that AIU opines that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. Staff states that AIU made both an economic argument about gaming and this operational argument, but failed to prove either of them.

With regard to AIU's "grandfather proposal" for Rider OT, Mr. Sackett does not consider it to be an adequate response to his concerns. He notes that under the grandfather proposal the services would still change to Rider T services, eliminating many of the advantages of Rider OT to customers and, thus, be detrimental to Rider OT customers. Mr. Sackett recommends retaining Rider OT services entirely and increasing its rates across-the-board. In light of the value of Rider OT to AmerenIP customers, he goes on to argue that if the Commission approves tariff standardization at this time, a similar service provision that appeals to smaller customers should be offered in all three service territories.

c. GFA's Position

GFA opposes eliminating AmerenIP's Rider OT. GFA contends that AIU's proposal is just one example of its willingness to make tariff structure changes to favor its own natural gas supply. Despite AIU's claims to grandfather Rider OT, GFA states that AIU's plan only retains monthly rate values increased by the proposed across-the-board percentage increase. All other terms and conditions, GFA notes, will be pursuant to Rider T provisions. GFA asserts that AIU's Initial Brief is misleading where it states that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. According to GFA, the benefits of Rider OT are actually stripped by AIU's proposal to make all Rider OT terms and conditions to be pursuant to Rider T. GFA states that AIU recognizes that tariff conformity across three service territories will eliminate certain provisions enjoyed by certain customers, but AIU again is only willing to conform tariffs when it is favorable to its own natural gas supply.

d. Commission Conclusion

AmerenIP's Rider OT does appear to have some benefits for smaller transportation customers, as Staff argues. In light of the Commission's earlier conclusion on storage banks and subsequent conclusions on daily telemetry and a small volume transportation tariff, however, the Commission does not believe that Rider OT remains a necessary vehicle for delivering those benefits to small transportation customers. Storage banks will also continue to exist for larger transportation customers and thus will not be needed under Rider OT. Grandfathering Rider OT for AmerenIP

customers currently taking service under it appears to be of little benefit as proposed by AIU and thus is not adopted. Elimination of AmerenIP's Rider OT in conjunction with the other rate design conclusions in this Order promotes uniformity in the tariffs of the three gas utilities without unduly sacrificing service to transportation customers. Accordingly, AIU's proposal to eliminate AmerenIP's Rider OT is approved.

4. Elimination of AmerenCIPS' Stand-by Reserve

a. AIU's Position

Of the three AIU gas utilities, only AmerenCIPS currently offers SBR service. AmerenCIPS provides SBR through its existing Rider T. SBR is a service that provides for full or partial system back-up during periods of curtailment. Customers desiring SBR service elect what portion of their gas load that they would like available during periods of curtailment. AIU proposes to eliminate AmerenCIPS' SBR service, claiming that few customers want this service and eliminating it will achieve consistency among the three gas utilities.

AIU acknowledges Staff's claim that 50% of eligible AmerenCIPS customers (74 customers) have or want SBR service and that it should continue to be offered. In response, AIU asserts that Staff's analysis is in error. AIU states that Mr. Sackett combined the number of Rider T and Rider S customers to determine the number of customers wanting SBR service. AIU notes, however, that he only used the number of Rider T customers to derive the percentage currently utilizing a designation amount greater than zero. Of those eligible for a partial designation, AIU contends that 0.4% actually utilize a designation greater than zero, rather than 20% erroneously claimed by Staff. Ameren Exhibit 30.7 shows the SBR option statistics for customers with Rider T, Rider S, and a combination of Rider T and S.

AIU notes further that prior to its 2002 rate case, Docket No. 02-0837, AmerenCILCO offered a SBR option called daily limited firm backup ("DLFB"). AIU reports that in that rate case, the service was eliminated due to limited participation by transportation customers. Additionally, AIU states that the elimination of DLFB was uncontested by all parties, including Staff.

Furthermore, AIU contends that there are not enough pipeline capacity resources in the Midwest to offer SBR service, which has its origins in the 1980's, when transportation services were new and untested. AIU explains that SBR was originally designed during the initial unbundling of transportation services to give a back-stop to the new and untested transportation services then being offered. Because it targets a reserve margin (available firm deliverability resources over a design peak day) of 3% for load growth between capacity agreement terms, statistical errors in modeling the peak design day, and minor customer switching, AIU asserts that it simply does not have any extra firm resources on a peak day to offer a SBR option. As evidence of the lack of capacity, AIU relates that the newest interstate pipeline under construction in the U.S., the Rockies Express Pipeline, is fully subscribed before going into service.

If it is forced to offer a SBR service for all transportation customers, AIU states that an additional 490,000 MMBtu of firm transportation capacity potentially would be required, at a cost of over \$74 million. AIU does not believe that it could secure this much firm capacity even if it wanted to, which makes Staff's request for this service a moot point. AIU adds that when a customer chooses to take transportation service, it is accepting the responsibility to secure its own gas supply and upstream transportation capacity resources, especially for a peak day. AIU insists that it should not be obligated to contract for supply services to serve as a back stop for transportation customers.

b. Staff's Position

Staff argues that AIU's proposal to eliminate AmerenCIPS' SBR service is another example of AIU's efforts to —~~standardize~~” the service offerings among the AIU LDCs, but which reduce services for transportation customers. Mr. Sackett recommends against allowing the elimination of this service. According to Staff, SBR service recognizes the need for operational flexibility and is a valuable service to transportation customers which should be retained as a cost-based service option. Staff adds that SBR service will become even more valuable if curtailments become more common due to the increasing pipeline constraints that AIU predicts. In that eventuality, Staff states that SBR would serve as a functional mechanism to ensure gas supply to customers when needed. Moreover, rather than eliminating the AmerenCIPS SBR option, Mr. Sackett recommends standardizing AIU's tariffs by offering SBR in all three service territories.

Mr. Sackett contends that AIU has provided no compelling reason to eliminate SBR. In attempting to justify eliminating the AmerenCIPS SBR option, Staff states that AIU makes two mutually exclusive arguments. First, Staff notes that AIU questions the popularity of SBR service among eligible customers. Then, Staff continues, AIU argues that it would not be feasible to provide SBR service if all customers that would be eligible took full backup under it.

Staff asserts that AIU's argument about SBR's lack of popularity is off the mark because its calculation includes the total number of commercial and industrial sales and transportation customers served by AmerenCIPS. Staff calculates that 74 AmerenCIPS sales and transportation customers are paying for a partial designation of greater than 0%. Staff contends that it is evident from their willingness to pay for SBR that they find it beneficial. Staff adds that there is no indication that the costs of SBR are not being recovered from the customers electing this service. Furthermore, Staff argues that the popularity of SBR can be most appropriately determined by considering the percent of Rider T customers taking SBR. These are transportation customers and therefore are the customers that Staff proposes should have access to the service from all three utilities. Staff asserts that according to AIU's own numbers, 20% of AmerenCIPS' transportation customers are designating a SBR amount greater than zero. Staff notes that transportation customers tend to fall in higher usage classes and may be subject to curtailment before the sales customers that are primarily in the lower usage classes.

Mr. Sackett concludes that it is inconsistent for AIU to on the one hand argue that the vast majority of AmerenCIPS' Rider T customers have elected a stand-by level of zero and on the other hand state that AIU could not find capacity to provide this service if all customers wanted this service at a full back-up level.

c. Commission Conclusion

The decision of whether to eliminate AmerenCIPS' SBR service is not easy. Clearly some customers find it useful enough to pay extra for it, as Staff asserts. At the same time, however, the Commission recognizes that pipeline capacity resources in the Midwest have become more constrained since the initiation of SBR service, as AIU argues. Upon weighing all of the arguments, the Commission is persuaded by AIU. As noted above, AmerenIP has no SBR option and AmerenCILCO's equivalent to the SBR service was eliminated in its 2002 rate case without dispute. In light of this historically declining interest in SBR service, the Commission does not believe that retaining AmerenCIPS' SBR service is warranted, let alone expanding it to all three gas utilities. Although it is unlikely that all customers taking SBR service would designate all of their load for the service, the Commission is also concerned about AIU's ability to secure capacity throughout its systems. Accordingly, AIU's proposal to eliminate AmerenCIPS' SBR service is approved.

5. Intra-Day Nominations

Generally, a nomination in the context of the gas industry is a request for a quantity of gas under a specific contract or agreement with a gas supplier. An intra-day nomination is a request for gas received during the same day on which the customer wants to take delivery of the gas. An intra-day nomination may also be a request for gas received after the normal nomination deadline for the following day. One or more intra-day nominations, while not mandated for all LDCs, are the industry standard.

The NAESB, and its predecessor the Gas Industry Standards Board, have developed various standards for the purpose of ensuring smooth and efficient operations between producers, pipelines, local distribution utilities, marketers, and others. NAESB is the industry forum for the development and promotion of standards which will lead to a seamless marketplace, and its process for development and implementation of standards is consensus-driven. Among the promulgations of NAESB is a recommendation that LDCs implement one or more of 4 intra-day nominations, specifically the Timely Cycle (before 11:30 AM on the day before flow), Evening Cycle (before 6:00 PM on the day before flow), Intraday 1 Cycle (before 10:00 AM on the day of flow), and Intraday 2 Cycle (before 5:00 PM on the day of flow). Intra-day nomination cycles provide transportation customers the ability to change nominations when necessary after the earlier deadlines have passed. The need to adjust nominations can arise for numerous unexpected reasons, including weather conditions, changes in a customer's production schedules, or pipeline or utility system disruptions. Many LDCs have either voluntarily or by mandate implemented certain of the NAESB intraday standards.

a. AIU's Position

AIU currently utilizes the Timely nomination cycle. AIU proposes the addition of one new intra-day nomination cycle for all three gas utilities to give transportation customers an additional option to adjust gas supply deliveries to minimize imbalances. AIU proposes to add a new intra-day nomination cycle at 4:00 PM on the preceding day and use its best efforts to accommodate other intra-day nomination changes. AIU is only willing to provide this additional nomination on normal business days.

In response to the suggestion that it provide all 4 NAESB nomination cycles, AIU urges the Commission to refrain from ordering it to do so. AIU argues that doing so is not necessary because other Illinois gas utilities do not offer all 4 NAESB nomination cycles, which suggests to AIU that there is no need for the additional cycles, that it presents an undue cost to ratepayers, and that there has been no credible demand for this service. AIU states that it will provide the 4:00 PM evening nomination and any other off-cycle nominations it is able to using its current staff and resources.

AIU reports that the majority of transportation customers and their marketers efficiently manage their nominations and have not requested intraday nomination deadlines. AIU states that it has worked with the transporters to support their occasional need to make late nomination changes. AIU adds that there is no credible proof that additional intra-day nominations will meaningfully assist utilities in managing imbalances on interstate pipelines. Furthermore, AIU will continue to provide nomination flexibility when possible, but indicates that it can not uphold a firm tariff obligation to provide intra-day nominations throughout all evening and weekends and holidays without providing additional staffing during the off business hours.

The need for added personnel, AIU continues, is not limited to handling the additional intra-day nominations. AIU relates that it must coordinate nomination changes with Gas Supply and Gas Control personnel in order to effectuate the changes. Offering intra-day nominations would require additional staffing during the off business hours for these groups as well. AIU operates a 24-hour Gas Control Center; however, it is staffed during off-business hours strictly for meeting the requirements of gas control and monitoring for the transmission system, on-system storage fields, distribution level operating pressures, and maintaining the integrity and safety of the systems.

With regard to CNE-Gas' contention that other utilities offer all 4 intra-day nomination cycles, AIU notes that CNE-Gas excuses Peoples, North Shore, and Nicor for not being among them because these utilities allegedly offer more flexible storage access. AIU responds that its proposed banking services and tolerance levels are comparable to what these other utilities have in place. Furthermore, AIU asserts that its storage assets are considerably more limited than what Peoples, North Shore, and Nicor have in place, as discussed by AIU witness Glaeser. According to Mr. Glaeser, Peoples and North Shore have considerably more "blended" storage than does AIU. Furthermore, AIU avers that Peoples and Nicor do not offer firm intra-day nomination

cycle rights. AIU states that Nicor has a strict nomination deadline of 11:30 AM the day prior to flow, with no flexibility for late nomination changes. In the recent Peoples/North Shore rate order, AIU reports that the Commission rejected the same arguments made by CNE-Gas. Moreover, AIU indicates that the utilities which CNE-Gas utilizes for comparisons, such as Pacific Gas and Electric Company and Southern California Gas Company, offer little resemblance to AIU in terms of the size of the their distribution systems, customer base, and employee numbers and, in fact, are the largest gas distribution systems in the U.S.

b. Staff's Position

Staff recommends that AIU be required to implement all 4 NAESB intra-day nominations. Doing so, Staff argues, will assist each LDC in maintaining its balances on the interstate pipelines. Staff states further that the additional costs to provide this service could be passed through to transportation customers in rates in subsequent rate cases. Staff points out that AIU can change its pipeline nominations twice during the gas day, but is not willing to pass this flexibility on to its transportation customers.

In support of AIU's position that there is no demonstrated need for these additional nomination cycles, Staff notes that AIU argues that most of its transportation customers have not requested intraday nominations and most of them manage their nominations efficiently. Since AIU did not consult with its transportation customers about its proposed offerings, however, Staff believes that AIU's first argument has no validity. If AIU had sought input from its customers prior to filing its service revision, Staff submits that it may have discovered that they do want this service. Additionally, the fact that AIU spent three rounds of testimony arguing that its transportation customers do not efficiently manage their nominations as a basis for its recommended changes weakens AIU's second argument on this issue, according to Staff.

Staff also notes AIU's dislike of CNE-Gas' comparison of AIU to other LDCs that offer these nominations as firm rights. Although AIU dismisses two of the other utilities on the grounds that they are significantly larger, Staff observes that this leaves seven other utilities for comparison, many from the Midwest. Staff also believes that AIU's comparison to Nicor, Peoples, and North Shore on this issue is not valid because all of these utilities offer enough flexibility that intra-day nominations would be less critical for them.

c. CNE-Gas' Position

CNE-Gas states that transportation customers, like utilities, may benefit from the use of intraday nominations to avoid imbalances or for other operational reasons. To aid in doing so, CNE-Gas provides suggested tariff language incorporating all 4 NAESB intra-day nominations. CNE-Gas asserts that such intra-day nominations would be similar to what AIU's own internal gas supply personnel do, by using this capability to help maintain supply stability. CNE-Gas suggests that AIU should discontinue its unduly discriminatory treatment of transportation customers and instead provide them

the same options for the same reasons AIU desires intraday nominations – to help manage its load requirements when unanticipated changes occur.

In response to AIU's observation that neither Nicor nor Peoples offers the 4 firm intra-day nomination cycles, CNE-Gas acknowledges that this is true and counters that both Nicor and Peoples provide transportation customers with greater, more flexible storage access. As CNE-Gas witnesses explained, many of these issues are interrelated. CNE-Gas contends that AIU's approach seeks to provide transportation customers with little flexibility on all the interrelated items, including both intra-day nominations and storage banks. In comparison, CNE-Gas states that Nicor offers no flexibility on intraday nominations, but substantially greater flexibility on the storage banks provided to transportation customers. In the recent Peoples case, CNE-Gas relates that the Commission authorized several tariff provisions granting greater flexibility to transportation customers such as intraday allocations, greater flexibility during delivery restrictions, expanded imbalance trading, and April through October daily storage injection rights of up to the average daily use in the parallel month of the previous year plus 0.67% of the customers Allowable Bank, with the ability to inject up to a customer's MDQ during the remaining months. With the added flexibility for transportation customers, CNE-Gas states that the Commission elected not to require Peoples to offer the greater flexibility of intraday nominations.

d. Commission Conclusion

The Commission appreciates the benefits that more intra-day nomination cycles could bring to AIU's gas distribution systems and the customers thereof. In light of uncertainties regarding the cost of implementing all 4 cycles, however, the Commission is not prepared to require AIU to provide all 4 at this time. To order AIU to provide new services in this rate case but defer cost recovery until AIU's next rate case is not appropriate. When preparing its next gas rate cases, AIU should determine the cost of providing all 4 nomination cycles and provide that information with its rate filing. The Commission would also hope that those favoring the addition of nomination cycles would offer evidence of specific/concrete benefits associated with additional nomination cycles. The Commission hopes to use such information to weigh the cost and benefits of implementing the 4 NAESB nomination cycles in AIU's next gas rate cases. In the meantime, the Commission approves of AIU's proposed 4:00 PM evening nomination cycle, in conjunction with its current Timely nomination cycle. The Commission also expects AIU to use its best efforts to try to accommodate any other off-cycle nominations it is able to using its current staff and resources, as it committed to doing.

6. Daily Telemetry

a. AIU's Position

AIU proposes to require customers taking service under GDS-4, GDS-5, GDS-6 (AmerenCILCO only) and Rider T to provide daily telemetry. AIU witness Glaeser explains that daily telemetry is needed so that AIU can be assured of timely

communication of transportation customer usage. He states further that daily telemetry allows AIU to provide transportation customers and marketers with more current data since the meter can be interrogated on a daily basis after 9:00 AM, which is the end of the gas day in the natural gas industry. AIU indicates that transportation customers and marketers would now have access to usage data from the previous day rather than usage from two days prior to the current gas day. Mr. Glaeser testifies that the daily telemetry requirements can be met with a dedicated telephone line, which can be an extension of an existing line. The line, however, could not be used for fax or any other purpose.

In response to GFA witness Adkisson's argument that the expense is not needed for small to intermediate and off-season transportation customers, Mr. Glaeser testifies that notwithstanding each customer's individual size, in the aggregate their usage can have a meaningful impact on the operations of the distribution systems. He adds that this concern of undue impacts can be exacerbated with regard to the smaller captive distribution systems within AIU's overall distribution systems. AIU offers the Crawford County area, as well as the Franklin, Hamilton and Perry County areas as examples of captive distribution systems. AIU states that daily information on transporters' usage can serve to prevent negative system impacts for these particular areas. Mr. Glaeser also notes that the requirement that these sized customers be subject to the daily telemetry requirements is not novel--AmerenIP already requires daily telemetry for transportation customers served under Rate 76.

Mr. Glaeser testifies further that there is a real benefit to transportation customers and their marketers by having this information in that they can better avoid higher cash-out prices. Moreover, he opines that in this day and age when state and federal policies abound with regard to the need for energy efficiency and responsible energy usage, these customers should bear some obligation to take measures by which to ensure responsible energy management. He went on to explain that, as a matter of fact, many transportation customers and marketers are desirous of this daily usage information. He testified that when such information is not posted on the management system in a timely basis, numerous inquiries are received from these customers/marketers. Even marketers who manage customers with relatively small loads that include the GDS-2 and GDS-3 customers are desirous of access to daily usage information in order to manage the aggregated imbalances associated with their customers. AIU does not respond to GFA's suggestion that if daily telemetry is required, that its installation be delayed until after November 2008.

With regard to GFA's concern about the additional expense of telemetry, AIU describes how GFA misunderstands AIU's proposal with a discussion of AmerenIP and a GDS-2 grain dryer customer. GFA asserts that a sales customer will see the incremental cost for telemetry increase to \$660 annually, whereas, if it is taking delivery service, as would a transportation customer, the overall annual increase is \$1,345. AIU explains that for an AmerenIP GDS-2 customer taking service under Rider T, the incremental cost for daily telemetry does increase, by the overall across-the-board increase, to \$660 annually, but the \$1,345 amount includes the annual daily telemetry

charges (\$660), as well as the increase to all other rate components within the rate. Thus, according to AIU, a current grain dryer customer taking service under GDS-2, who would also be taking transportation service under grandfathered Rider OT rate structure, will see the same across-the-board increase in GDS rates as a customer receiving sales service. AIU asserts that the current grain dryer customer taking transportation service under AmerenIP's Rate 76 (proposed Rider T) will realize the same across-the-board increase in GDS rates as customers receiving sales service.

In response to Mr. Sackett's concern that a \$55 per month charge for telemetry presents an economic barrier for smaller customers and may force some transportation customers to move back to system supply, AIU asserts that such claims are simply wrong. First, AIU states that nothing is unique or novel about this particular charge. AmerenCIPS currently charges \$55 per month for the same equipment, and the AmerenIP Rate 76 Facilities Charge and Advance Metering and Telecommunications Charge total \$37.75 per month. Second, AIU asserts that the evidence is that small transportation customers at both AmerenCIPS and AmerenIP are not being deterred by paying these monthly charges. AIU states that there are many customers taking transportation service and are paying these charges. AIU witness Warwick testifies that AmerenCIPS has 125 small transportation customers while AmerenIP has 182 accounts under its Rate 76.

AIU acknowledges 4 objections made by Mr. Sackett in response to Mr. Warwick's testimony: (1) the number of small customers taking transportation service are a small percentage of eligible customers, (2) the conclusions drawn stem from current metering differentials and not the proposed charges, (3) while the metering charge may not be a barrier for some smaller transportation customers, it could still be a factor for others, and, (4) while it may be economical for current customers, it may keep other marginal customers from benefiting from transportation services. AIU contends that it is readily apparent that the majority, if not all, of Staff's objections are speculative and not grounded in any credible evidence. Mr. Warwick testifies that less than 1% of the small transportation customers eligible take such service from AmerenCILCO, which does not require a telemetry charge, suggesting Staff's claim that more customers would be interested fails. Mr. Warwick also emphasizes that the magnitude of the telemetry charges is driven by the across-the-board revenue allocation such that each rate value, including the telemetry charges, are being changed equally by the across-the-board percentage change. Taken to its logical extreme, any increase in any of the AIU rates may cause major behavioral changes on the part of all of its customers but, of course, such a result is not realistic. AIU asserts that there are cost increases and the affected businesses become more efficient, reduce their own costs, or pass them along to their customers. AIU states that it is difficult to conclude that a charge of less than \$2 a day would prevent a customer from utilizing transportation service.

b. Staff's Position

To the extent that daily balancing is not necessary, Staff sees no reason for daily telemetry. Staff is also concerned that the expense of daily telemetry may discourage

some customers from becoming transportation customers. Staff also suggests that AIU apparently does not understand that some customers may not have an extra \$660 or \$660.00 per year for telemetry fees lying around. According to Staff, the additional fee puts marketers at a disadvantage because they not only have to beat the PGA cost, they also have to beat it by this additional amount as well. Staff adds that AIU witness Warwick testifies that other factors would affect a customer's decision to remain on sales service and that the move to daily balancing, the loss of a bank, the requirement for a dedicated phone line, and a reduction in a daily balancing could all be factors.

In response to AIU's claim that because some small customers are taking service with daily balancing and telemetry there must be no barrier for anyone, Staff argues that there may be many other smaller customers that are not taking transportation service because they can not get gas priced competitively enough to beat not only the PGA but also the costs associated with the daily balancing and cashout and the telemetry and metering charges. With regard to AIU's observation that AmerenCILCO does not have daily balancing and metering requirements but only a few transportation customers, Staff submits that it is really AIU's unfavorable policies that keep customers, especially the small ones, from finding transportation service to be desirable. Staff fears that the number of transportation customers is likely to grow smaller if AIU's restrictive proposals are approved.

c. GFA's Position

GFA understands that daily telemetry is a useful and necessary tool for large users to manage the system's daily operation, but contends that daily telemetry is not necessary, nor an industry standard, for predictable small to intermediate users. For example, GFA states that telemetry requires the additional cost to obtain and maintain metering equipment. In addition, the user will pay one-time installation costs as well as the monthly cost of a dedicated phone line. On top of those costs, the user will incur additional administrative costs to manage the daily use data. GFA argues that all of these costs are justified for large users who need to manage the daily operation of the system, but are simply too large and disproportionate to the use of small and intermediate users. Indeed, GFA continues, the large cost results in an economic incentive for transportation users to switch to AIU supply. For example, under AIU's proposal, GFA reports that a small AmerenIP GDS-2 grain dryer customer under sales service will see its incremental cost for telemetry grow to \$600 or \$660.00 annually. If it is taking delivery service, its overall increment, compared to sales service, will increase to \$1,345.00.

GFA disagrees with AIU's assertion that daily telemetry information helps transportation customers avoid higher cashout prices. The fallacy of that statement for a small grain dryer is obvious, according to GFA. GFA explains that the additional cost of AIU's filed tariffs has a bias in favor of its sales service supply by \$2.24 per dekatherm relative to transportation service, which far exceeds what a small customer could expect to make up by avoiding higher cash-outs. In response to AIU's claim that some GDS-2 and GDS-3 customers or marketers would like to have daily usage

information, GFA states that daily telemetry should be an option for those willing to pay for it.

GFA states that AIU's purported justification is that it would be nice to have daily telemetry to be able to monitor actual usages and manage imbalances in the system. AIU also suggests that it is good — ~~overall energy policy~~ — to require daily telemetry. All of that, GFA asserts, ignores the significant, and hugely disproportionate, cost to the small to intermediate users. Instead of being good overall energy policy, GFA views this proposal as a thinly veiled attempt by AIU to force transportation customers to take AIU supply.

To see the lack of necessity for daily telemetry, one need look no further than other suppliers within Illinois, as well as the rules applicable to Missouri and Iowa utilities, according to GFA. Nicor, Peoples, North Shore, Mid American Energy Company, and AmerenCILCO currently offer small volume transportation service without telemetry. The State of Missouri, GFA states further, prohibits telemetry charges for small volume transportation for Missouri schools, which is applicable to AmerenUE, Laclede Gas Company, Missouri Gas Energy Company, Atmos Energy, Aquila, and any other utility regulated by the Missouri Public Service Commission. (See 393 Mo.Rev.Stat. §393.10) Furthermore, GFA reports that the Iowa Utilities Board recently ordered all Iowa investor-owned utilities to offer small volume transportation service without telemetry to all non-residential customers. These other utilities and state statutes and rules demonstrate that daily telemetry for the small to intermediate users is simply not necessary.

d. Commission Conclusion

The Commission understands AIU to propose that all Rider T transportation customers and all sales customers taking service under GDS-4, GDS-5, and GDS-6 (AmerenCILCO only)¹³ to provide daily telemetry. Transportation customers otherwise eligible for service under GDS-2 and GDS-3 would provide daily telemetry under Rider T. Sales customers under GDS-2 and GDS-3 would not be required to provide daily telemetry.

The Commission agrees with AIU that daily telemetry can provide useful information, but does not understand the sales vs. transportation distinction that AIU draws between customers eligible for GDS-2 and GDS-3 service. The record lacks any explanation for why daily telemetry is not necessary for small sales customers but is for small transportation customers. In light of the cost of daily telemetry, the Commission views the proposed requirement on small transportation customers as a deterrent to taking transportation service. Accordingly, AIU may not require all transportation customers otherwise eligible for service under GDS-2 and GDS-3 to provide daily telemetry. Nor may AIU require small seasonal gas transportation customers otherwise eligible for service under GDS-2 or GDS-3 to provide daily telemetry. AIU shall, however, offer a daily telemetry option to such transportation customers in the same

¹³ AmerenCIPS and AmerenIP do not have a GDS-6 rate class.

manner that other, larger transportation customers provide daily telemetry or on more favorable tariffed terms to the customer if costs prove to be less for smaller customers. AIU's proposal to require remaining Rider T customers and GDS-4, GDS-5, and GDS-6 customers to provide daily telemetry appears reasonable and is approved.

7. Small Volume Transportation Tariff

a. Staff's Position

Staff witness Sackett recommends implementing a small volume transportation tariff for all three utilities if the Commission determines that tariff standardization is appropriate at this time. He suggests a transportation service that balances monthly and does not require daily metering for smaller customers. He asserts that daily metering and balancing are unnecessary for smaller customers because they do not place the same constraints on the system as large customers. Mr. Sackett states further that no metering charge should be assessed beyond what these smaller customers would need for system supply service. With regard to telemetry, if the customer would not need telemetry as a sales customer, he does not believe that the customer should be required to have telemetry as a transportation customer.

Mr. Sackett notes that AIU already offers daily balancing and no telemetry in AmerenIP's territory under Rider OT and under existing Rider T in AmerenCILCO's territory. Therefore, he suggests that it should not be unduly difficult to add this to AmerenCIPS' tariff, as well. Mr. Sackett contends that AIU did not respond in either its rebuttal or surrebuttal testimony to his proposal to add a small volume transportation tariff for all three utilities. Since no party objected to this recommendation in their testimony, he asserts that the Commission should adopt it (if the Commission adopts tariff standardization).

b. AIU's Position

AIU objects to the implementation of a small volume transportation tariff and opposes monthly cash-outs for any sized customer. In addition, AIU finds Staff's position regarding proposed monthly cash-outs for small volume transportation customers to be at odds with Staff's own take on the benefits of daily cash-out. Specifically, AIU notes that Mr. Sackett agrees that daily cash-outs would help to eliminate gaming as part of his argument that bank services should remain. AIU adds that Mr. Sackett's position is consistent with Staff's position in AmerenIP's last gas rate case, Docket No. 04-0476. According to the Order in Docket No. 04-0476, Staff agreed with AmerenIP that daily balancing would prevent a certain amount of gaming in the monthly balancing and cash out procedures. (Order at 90)

c. GFA's Position

GFA expresses discontent with AIU's transportation tariffs. GFA states that it sponsors a natural gas purchasing and transportation pool for its members. These

members are predominantly small and intermediate size grain dryers. GFA witness Adkisson testifies that its members are seriously considering switching to sales service with AIU supply because the proposed AIU transportation tariffs are so onerous.

d. Commission Conclusion

The Commission has considered the arguments for and against a small volume transportation tariff and concludes that the proposal has merit. Staff has persuaded the Commission that a simple straight forward transportation tariff for customers eligible for service under each utility's GDS-2 and GDS-3 rate classes is reasonable, including small seasonal customers taking service under GDS-5 who are otherwise eligible for service under GDS-2 and GDS-3. The tariff, which may be either part of Rider T or a separate tariff, shall provide for monthly balancing and not require daily metering. The Commission does not perceive a need at this time for anything more than monthly balancing for smaller customers. No metering charge should be assessed beyond what these smaller customers would need for system supply service. As discussed above, smaller transportation customers will have an option of utilizing daily telemetry. The Commission anticipates that this determination will make transportation service more available to small customers. The Commission would welcome an evaluation of the small volume transportation tariff from AIU, Staff, or any interveners in AIU's next gas rate cases.

8. 12-Month Notification for Seasonal Customers

a. AIU's Position

Both AIU's existing tariffs and its proposed Rider T require customers to notify AIU by July 1 of each year if they wish to change to or from transportation service effective the following November 1. Because the order in this proceeding will come after July 1, 2008, AIU proposes a later date for the year 2008 by which a notice of service change must be given. Specifically, eligible customers must provide notice of their choice by the later of October 17, 2008 or 14 days after compliance tariffs become effective.

As a compromise, AIU proposes, due to the unique nature of grain dryers, to change seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year. The general tariff requirement to remain on this rate for 12 months would not change. AIU believes that the proposed offer to change the notification date to April 1, with the sales service to be effective August 1 of the same year, would resolve the timing issue identified by GFA. AIU clarifies that it will continue to offer other transportation customers the one-time right to change the election for sales service before October 17, 2008, and will notify customers of this option through e-mail and AIU's internet-based USMS, which is an on-line management software system used to maintain daily usage, nominations, and billing information.

In making the proposed compromise to require notification by April 1, AIU does not fully accept Staff's position or any of GFA's various proposals. Rather, AIU contends that its proposal represents a reasonable accommodation to certain seasonal users, such as grain dryers and some asphalt plants, with production in later summer and fall. Expanding the notice compromise to all customers with low winter usage, as Staff and GFA propose, or to all customers who qualify for GDS-5 (as opposed to those who take service under the tariff) is not appropriate, according to AIU. As AIU witness Glaeser explains, off-seasonal use transport customers can create detrimental system impacts if not managed properly. Some of the firm transportation capacity contract levels for AIU ratchet down during the shoulder months, including September and October, when grain dryers typically have heavy usage, in order to follow the load shape of the system sales customers. Additionally, AIU states, this transportation capacity is used at high load factors during the shoulder months and summer to transport gas supply for storage injections into off-system and company owned storage facilities. AIU asserts that capacity for its systems can and does become constrained throughout the year, not just during the peak winter season. AIU contends that this is evident by the pro-rata reductions in primary firm transportation capacity on Panhandle Eastern in May 2008. As a result, AIU claims that allowing all customers with low winter usage to provide 4 months notice, as proposed by Staff (or 30 days as proposed by GFA) would be detrimental to AIU's planning for winter season usage. An April 1 notification date, for service on August 1, would address the GFA's concerns about the impact on grain dryers during the drying season. Therefore, AIU concludes that its compromise to change the seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year is reasonable and should be adopted.

b. Staff's Position

While AIU's July 1st notice proposal makes sense for those customers needing to use most of their gas during the winter months, Staff states that it makes little sense for customers who will have little impact during those same months. Therefore, Staff witness Sackett recommends that all customers with less than 5% of annual usage occurring during December through March be required to provide a four-month advance notice before moving between system and transportation service regardless of the GDS that they take service under. Mr. Sackett's four-month notice proposal preserves the four-month notice period currently in effect and in proposed Rider T. Staff asserts that this proposal allows for notice to be provided at the beginning of the injection season for grain dryers.

Staff understands AIU to have accepted at least part of Staff's recommendation. Staff notes, however, that there are two important distinctions between AIU's proposal and Mr. Sackett's recommendation. AIU's proposal only addresses those customers on GDS-5 and it will be for April 1st instead of four months. Mr. Sackett's proposal would apply to all customers with less than 5% of annual usage occurring during December through March and would be a four-month notice. Thus, AIU's proposal would only benefit grain dryers with the four months and not work for other seasonal users whose usage does not pattern the grain dryers. AIU witness Glaeser admitted that his

proposal does not address all of Mr. Sackett's concerns. Since AIU acknowledges that its position does not address all of Staff's concerns, Staff argues that AIU's proposal should be rejected and Staff's should be adopted.

c. GFA's Position

GFA finds the October 17, 2008, special one-time notice offer under proposed Rider T a problem for grain dryers for the 2008 harvest, which will already be in progress, if not nearly over. Even more importantly, for off-season users, the proposed on-going July 1 notification is a major problem beyond 2008, according to GFA. GFA is concerned because AIU's proposal requires grain dryers to give notice two harvests in advance. For example, the September-October, 2010, harvest is within the 12-month period beginning November 1, 2009, and ending October 31, 2010. As proposed by AIU, GFA states that GDS-2 and GDS-3 customers would be required to give AIU notice regarding the 2010 harvest by July 1, 2009. That notification date, July 1, 2009, occurs before the 2009 harvest. AIU's proposed notice requirement results in small and intermediate grain dryers having to give notice two harvests in advance. GFA complains that this proposal will require grain dryers to decide by July 1, 2009 their gas usage that will not begin until some 14 months later, in September of 2010. GFA avers that attempting to make that determination so far in advance will be difficult and risky. Rather than take that risk, GFA states that many grain dryers will likely just change to AIU supply. GFA maintains that the notification requirement is yet another method by which AIU is attempting to influence transportation customers to switch to AIU supply.

GFA states further that AIU will not offer to GDS-3 and GDS-4 customers the reasonable notification requirements available to GDS-5 customers. GFA observes that for seasonal GDS-5 customers, AIU has offered to change the notification requirement to April 1 to be effective August 1 of the same year. GFA asserts that does not solve the issue for smaller to intermediate seasonal use grain dryers. Unless and until AIU's GDS-5 tariff is designed for small and intermediate, as well as large users, GFA states that most dryers with seasonal use that qualify for GDS-5 can not economically take GDS-5 and therefore take service under GDS-2 or GDS-3 tariffs. Those GDS-2 and GDS-3 customers are not being offered the April 1 notification to be effective August 1, despite having the same seasonal use pattern as GDS-5 customers.

GFA proposes that the GDS-5 notification provision (April 1 notice to be effective August 1) be applicable not only to GDS-5 seasonal customers, but to all seasonal customers that qualify for GDS-5, whether or not they choose to take service under GDS-5 (such as grain dryers who choose to remain on GDS-2 or GDS-3). GFA suggests that this proposal would eliminate the discrimination against small and intermediate seasonal users. Alternatively, GFA proposes that seasonal use customers, with less than 5% of annual use in the months of December through March, should not be required to stay on transportation service for 12 consecutive months. Instead, such users could stay on transportation service through March if transportation service commences after December 1 and before April 1. GFA states that both of these

solutions would alleviate the harshness imposed with the two harvest notice requirements proposed by AIU.

d. Commission Conclusion

At a minimum, grain dryers under GDS-5 should be allowed to provide notice by April 1 of each year whether they intend to be a transportation customer or sales customer beginning August 1 of that same year, on which AIU, Staff, and GFA all appear to agree. Whether other seasonal users of gas eligible for service under GDS-5, regardless of whether they actually take service under GDS-5, should be able to operate under the same notice provisions is less clear. AIU appears to have legitimate capacity concerns in conjunction with allowing all small and intermediate seasonal users to provide April 1 notice of a switch between sales and transportation service. Although the Commission does not adopt such a broad application of the April 1 notice provision in this proceeding, the Commission is interested in considering this idea further and invites discussion of it in AIU's next gas rate cases. In the meantime, however, given the nature of grain dryers' seasonal use, the Commission finds that grain dryers under GDS-2 and GDS-3 should also be allowed to provide such notice by April 1 of each year, for the period beginning the following August 1. With regard to waiving or modifying the general tariff requirement that grain dryers remain on the rate for 12 months, the Commission is not prepared to do so at this time in absence of assurances that gaming would not occur.

9. Minimal Winter Use Delivery Service Provisions

a. AIU's Position

With respect to AmerenCIPS, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 3 and Rate 4. With respect to AmerenCILCO, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 600. In both instances, AIU proposes to include such language in its proposed new GDS-5 -- Seasonal Gas Delivery Service.

AIU also asserts that upon reviewing Staff's Initial Brief, it learned of several new and significant changes in gas rate design related to —seasonal load” being recommended by Staff (discussed below). AIU states that Staff's recommendations lack supporting citations to the record as to their scope, applicability, or impacts on all affected customers. AIU goes on to state that the novel changes recommended by Staff are extremely problematic as well as markedly vague. All of the recommendations related to changes to accommodate —seasonal load.” AIU contends, however, that Staff fails to provide a definition of —seasonal load” in its Initial Brief. Because natural gas is used for heating, AIU observes that a large number of all customers use natural gas seasonally. AIU maintains that it is unclear from Staff's recommendation what the parameters of —seasonal” use would be.

Additionally, AIU avers that converting demand charges to volumetric charges involves a major change in rate design elements. AIU also notes that a major theme in Staff's rate design testimony is its assertion that all rates for customers should increase equally across-the-board to the extent feasible. AIU argues that converting a demand charge to a volumetric charge is inconsistent with that theme because doing so will result in unequal customer impacts. Finally, AIU insists that Staff's assertion that AIU has not provided credible support for why customers should require demand charges is incorrect. AIU contends that it provided ample expert testimony on the subjects of telemetry and the inappropriateness of eliminating demand rates.

b. Staff's Position

In response to AIU's proposal to include the Minimal Winter Use delivery service provisions in GDS-5, Staff witness Harden agrees that doing so is an appropriate means of conforming AIU's gas rate classes with its electric rate classes since it would not result in unequal bill impacts for individual gas customers. In its Initial Brief, Staff also voiced support for various GFA proposals concerning seasonal usage. GFA argues that seasonal customers do not place constraints on the system and therefore should not be assessed a demand charge. GFA also wants a volumetric charge for any customer with a seasonal load profile. GFA proposes that it should not be required to have daily balancing and telemetry as well. AIU witness Glaeser presents a counter-argument concerning an isolated incident where on one captive system, a single seasonal customer, has more than half of the load on that system.

Staff contends that AIU is attempting to use anecdotal evidence to prove that it must take a certain course of action. In this situation, however, Staff argues that AIU's example is not even close to being representative of the typical grain dryer. The one customer that it used, Staff notes, was not even a grain dryer. Another reason that Staff believes that AIU's response should be dismissed is because the issue is not directly related to these customers being transportation customers. Staff contends that the situation of the customer Mr. Glaeser used in his example would be the same if it were a sales customer, because its load is still unpredictable and the size of its usage relative to the captive system load would not change. Some exceptions may require daily metering, but AIU has provided no reason to conclude that most seasonal customers place such a load on the system that they need either daily balancing or telemetry, according to Staff. Staff therefore recommends that the Commission adopt GFA's proposal that customers with a seasonal load should not be required to balance daily and have daily telemetry regardless of which GDS they would otherwise be on. Also, because AIU has failed to provide a credible rationale for why seasonal customers should have demand charges, Staff recommends that the customers who would not be required to have a demand charge under the non-seasonal GDS classes, should not face a demand charge under GDS-5.

c. GFA's Position

GFA recommends that the demand charges in GDS-2 and GDS-3 be converted to volumetric charges, a recommendation which AIU opposes. GFA argues that non-winter seasonal use customers do not place constraints on the AIU distribution system, and therefore should not be charged a demand charge. GFA states further that AIU has not provided evidence that a demand charge, particularly a year-round demand charge, is appropriate for customers with minimal winter use (less than 5% of annual usage occurring during December through March). GFA observes that Mr. Glaeser uses a single anecdotal example of a seasonal customer on a captive part of the AIU distribution system (one pipeline supply). Because AIU's distribution system capacity is obviously underutilized during non-winter periods, GFA asserts that there is no justification for AIU to require demand charges for small and intermediate use customers with minimal winter use. GFA finds Staff's reasoning sound when it recommends that customers who would not be required to have a demand charge under the non-seasonal GDS rate schedules should not face a demand charge under the GDS-5 seasonal rate.

d. Commission Conclusion

AIU's proposal to include the Minimal Winter Use delivery service provisions from AmerenCILCO's Rate 600 and AmerenCIPS' Rates 3 and 4 in the new proposed GDS-5 does not appear to be opposed by any party. This proposal is reasonable in the Commission's opinion and is adopted. Other issues under this heading are less clear.

The elimination of the demand charge for non-winter gas customers as well as minimal winter use customers is an intriguing idea, but without more information, the Commission is not prepared to adopt these proposals at this time. One concern that causes the Commission to hesitate in adopting this proposal is the uncertainty surrounding the degree to which non-winter gas users affect the apparently increasing non-winter demand for gas. The ease/difficulty of converting demand charges to volumetric charges is another area of concern for the Commission. Without knowing more about how this would be accomplished, the Commission is reluctant to direct that it be done. The Commission invites further discussion on these issues in AIU's next gas rate cases.

With regard to daily balancing and telemetry for customers on GDS-5, the Commission is not persuaded at this time that such are not appropriate for larger sales or transportation seasonal customers. Accordingly, the Commission rejects Staff's and GFA's proposal that larger seasonal customers be free of any requirement to use daily balancing and telemetry. As discussed above, however, in the general discussions of daily telemetry and a small volume transportation tariff, the Commission is of the opinion at this time that daily balancing and telemetry are not necessary for transportation customers who would otherwise be GDS-2 and GDS-3 sales customers. Similarly, the Commission does not believe at this time that GDS-2 and GDS-3 sales customers should be required to provide daily balancing and telemetry. In the absence of any

persuasive arguments to the contrary, the Commission sees no need for daily balancing and telemetry for such smaller seasonal customers.

10. Uniform Terms Among Tariffs

GFA witness Adkisson is troubled by the fact that GDS-2, GDS-3, GDS-4, and GDS-5 have differing maximum use qualifications among the three utilities. He suggests implementing uniform use qualifications among corresponding GDS rates for all three utilities. GFA notes that AIU cites the need for rate continuity and stability, as well as the need to make changes gradually. Although AIU proposes continuity and stability here, GFA asserts that AIU abandons those principals when it wants to make tariff changes. GFA contends that AIU's inconsistencies point to its attempts to influence customers toward AIU supply.

AIU does not find GFA's concerns on this issue valid. AIU states that its rate design objective was to conform rates to the maximum extent possible while still maintaining rate continuity and stability. According to AIU, Mr. Adkisson's recommendation to conform the GDS rate qualification provisions among the three utilities might compromise the AIU rate continuity and stability goal.

AIU points out that Mr. Adkisson provides no analysis of the effects (i.e., customer rate migration, revenue instability, customer bill impacts, or cost analysis) of his proposed recommendation. Without thorough analysis, AIU fears that constructing a different rate design would inappropriately expose it to possible revenue erosion and run counter to the way rate classifications are set today. AIU maintains that GFA's recommendations will require a complete analysis of the affected service classifications to determine realignment of class billing determinants, and also require estimates and assumptions made for expected customer migration.

If the Commission agrees with Mr. Adkisson's rate design recommendation, AIU states that the final rates would need to be developed only after a detailed analysis of the recommendation, so as to determine the respective billing units for each affected service classification. The determination of billing units would also need to take into consideration the effects of rate migration, if any. AIU argues that this process would be necessary to ensure that, at the end of the day, the compliance rates filed in the case provide AIU with a reasonable opportunity to earn the rate of return granted in this case. AIU adds that the Commission would have to allow adjustments to other rates in order for the utilities to make-up any revenue shortfall created by his proposal.

The Commission understands GFA's concern. While some consistency exists among the maximum use qualifications for the GDS-2, GDS-3, GDS-4, and GDS-5 rate classes among the three utilities, obvious inconsistencies also exist. The Commission would also prefer that these tariffs be much more similar. Because this is the first "incarnation" of the GDS rate classes and because no analysis of the effects of more uniform GDS rate classes has been done, however, the Commission is not prepared to direct that AIU implement uniform maximum use qualifications for the GDS-2, GDS-3,

GDS-4, and GDS-5 rate classes among the three utilities in this proceeding. Instead the Commission directs AIU to study the impact of GFA's proposal prior to its next gas rate case. If AIU finds that greater uniformity is warranted, its rate filing should reflect the results of that study. If AIU finds that greater uniformity is not warranted, it should be prepared to explain why and provide the results of the study if asked during the discovery process.

11. Weather Normalization

AIU calculated billing determinants in this case based on 10-year weather normalized averages. AIU witness Laderoute presents testimony showing that 10-year normals are a better predictor and more representative of “normal” weather than 30-year normals in this case. He conducted a number of detailed statistical tests that are used by meteorologists and climatologists in studying weather and normals to test the validity of this conclusion, using historic National Oceanic & Atmospheric Administration weather data for Champaign-Urbana. AIU states that no party challenged the validity of Mr. Laderoute’s testing, data, or conclusions.

In his direct testimony, Staff witness Sackett concluded that AIU's proposal to use a shorter weather period was acceptable, but recommended that AIU provide a weather study similar to that used in the Peoples/North Shore gas rates cases, Docket Nos. 07-0241 and 07-0242 (Cons.). He indicated that the weather study should provide additional weather normalization data sets between 8 and 12 years in length, and compare such sets with a 30-year data set to determine the predictive quality of each set. Mr. Sackett requested the information because he understood the Order in Docket Nos. 07-0241/07-0242 (Cons.) to require him to do so. Mr. Laderoute provided the requested data and analysis in his rebuttal testimony, and concluded that the 8-, 11-, and 12-year normalized data sets are comparable to the 10-year normals in this case, and are therefore more predictive than the 30-year normal results presented in his direct testimony. Mr. Sackett agrees that AIU's approach is reasonable and not inappropriate.

The only issue to address is whether the Order in Docket Nos. 07-0241 and 07-0242 (Cons.) requires all utilities in the future to provide additional data sets and compare such sets with a 30-year data set to determine the predictive quality of each set. AIU does not believe that the Commission has required utilities in all future rate cases to provide a range of data to support their chosen weather normalization period, to determine which is the most predictive. AIU contends that this interpretation would be cumbersome and unnecessary. AIU acknowledges that the Commission adopted a more predictive approach to weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.), to further the Commission’s goal of setting “rates with the greatest likelihood of generating the Utilities’ allowed annual revenues.” (Docket Nos. 07-0241 and 07-0242 (Cons.), Order at 123) Mr. Laderoute’s recommendations, AIU adds, are consistent with this goal.

Understanding the background associated with this issue may facilitate discussion. In the Peoples/North Shore rate case, the Commission noted that it would

have expected a 30-year data set to be more predictive, based on the general statistical principle that more data regarding varying conditions is better than less. But after having considered the 8-, 11-, and 12-year normals, as well as the evidence presented in Nicor's most recent rate case (Docket No. 04-0779), the Commission concluded that there was no stable long-term trend in weather that would justify adhering to a 30-year normal. Furthermore, in adopting a 10-year normal in the Peoples/North Shore case, the Commission did not adopt the most predictive weather data set. In that case, the Commission made a decision between the most predictive data sets presented in light of all of the evidence.

In this case, AIU has shown that 11-year normals appear to be the most predictive set, but that adoption of 10-year normals presents a similarly predictive result and is reasonable in this case. Although Mr. Sackett agrees with Mr. Laderoute, Staff asserts that AIU provided no reason why a 10-year normal is as good as or better than the 11-year normal. AIU merely concludes that because the 10-year falls between the 11-year and 8-year normal in length that it was, —orbalance,” appropriate. AIU also notes that all of its billing determinants and resulting rate design data in this case are based on 10-year weather normalized data. Parties have not had the opportunity to review and respond to rate design evidence developed using alternative heating degree days, from alternative weather norm data sets.

While Staff recognizes that the Commission is not bound by its prior decisions, it still maintains that all utilities must provide the additional weather data discussed in Docket Nos. 07-0241 and 07-0242 (Cons.). Staff points out that the Commission required that all subsequent rate cases follow the procedures it adopted in that case, stating that, —In subsequent rate cases, we will expect utilities to employ the principles and methods approved here or bear the burden of proving that additional measures will materially enhance the alignment of allowed and actual revenues.” (Order at 125-126)

The Commission concludes that AIU's use of a 10-year weather normalized average is acceptable and is hereby approved. The Commission also appreciates Staff's observance of the conclusion on weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.). While it is correct that the decisions of the Commission are not res judicata, nothing prevents Staff or the Commission from recognizing the value of an earlier decision and applying the same principles to another proceeding. In this instance Staff sought additional information consistent with the weather normalization conclusion in the Peoples/North Shore Order in order to ensure that use of 10-year averages is appropriate. AIU provided the information and the primary question was resolved. To facilitate the resolution of this issue in future AIU rate cases, the Commission directs AIU to provide comparable data sets as it did in this proceeding with its initial filing. Staff is not barred from seeking other data sets for comparison purposes.

12. Imbalance Trading

a. AIU's Position

Prior to its decision in this proceeding to offer banking, AIU offered to provide an imbalance trading mechanism to transportation customers. AIU witness Glaeser explained that a transportation customer or marketer could monitor its imbalance position during the month through the USMS. Mr. Glaeser further explained that transportation customers could choose to contact another transportation customer or marketer served from the same interstate pipeline and trade off-setting imbalances. The parties involved in the trade would be required to provide confirmation that the trade, in fact, had been agreed upon. Thereafter, AIU would change each customer's imbalance position within the USMS. Mr. Glaeser went on to testify that modifying the USMS system in order to accommodate imbalance trading would take time, as significant software changes are needed.

AIU now contends, however, that subsequent developments in this proceeding have eliminated the need for the imbalance trading service. The imbalance trading mechanism was intended to help transportation customers and marketers manage daily imbalances in order to minimize daily and monthly cash-out charges. As Mr. Glaeser explains in his surrebuttal testimony, AIU is now proposing to offer banking services which satisfies the same objective. AIU adds that with the offer of banking services, the imbalance trading service is no longer needed since the bank balance can be transferred between transportation customers and marketers. Mr. Glaeser also explains that bank limit balances between transportation customers served by the same interstate pipeline are transferable after confirmation from both counterparties. As AIU moves from the current bank services offered under the existing tariffs to those that it now proposes, AIU states that any balance in excess of the new bank limit maximums will be cashed out at the average of the Chicago City Gate first of the month price for the prior 12-month period after the customer avails itself of any bank balance trading with other customers. Consequently, because proposed banking service fulfills the same purpose as imbalance trading service, AIU withdraws its imbalance trading proposal and urges the adoption of its proposed banking service.

AIU notes CNE-Gas' concern that the bank services may not sufficiently make up for the absence of imbalance trading. In response, AIU states that the requisite functionality will be provided. AIU also asserts that CNE-Gas' effort to tie AIU to a Peoples tariff should be disregarded. According to AIU, there has been no factual demonstration to show that AIU's systems can accommodate the specifics associated with the Peoples tariff.

b. Staff's Position

Staff understands that AIU is withdrawing its proposal to provide for imbalance trading on the grounds that it is no longer necessary in light of AIU's newly proposed bank balance trading. Staff states that AIU's proposal to trade bank balances does not

directly affect the daily imbalances that customers face. Staff witness Sackett, however, agrees that, with any of the bank proposals, the need for imbalance trading is limited.

c. CNE-Gas' Position

CNE-Gas understands that AIU has withdrawn its imbalance trading service since AIU does not believe it is necessary with a banking service. CNE-Gas is concerned by this change but acknowledges that once actual tariff sheets setting forth the terms and conditions of the banking service are available for examination, the transfer of bank limit balances may provide some of the imbalance trading that transportation customers functionally require. Although the operation of imbalance trading may be different with and without a storage bank, CNE-Gas asserts that imbalance trading remains a valuable tool for transportation customers. CNE-Gas' concern is that even with storage banks, transportation customers need to have the ability to trade their bank imbalances with others. Whether this is called "Imbalance Trading" per se is not important to CNE-Gas; what is critical is that the functionality exists. CNE-Gas seeks functionality on par with that described in the Peoples/North Shore Order.

Although under the Peoples/North Shore Order imbalance trading is not allowed between customers of different utilities, for instance between customers of Peoples and North Shore, CNE-Gas indicates that there are no additional restrictions related to upstream pipelines. CNE-Gas states that this is one key distinction between imbalance trading, as discussed in the Peoples/North Shore Order, and the transfer of bank limits mentioned in Mr. Glaeser's surrebuttal testimony. Since imbalances offset one another under imbalance trading, CNE-Gas contends that AIU should be indifferent and there is no adverse impact on utility operations. CNE-Gas recommends that the Commission direct AIU to include imbalance trading, similar to the Peoples/North Shore Order described above, in its transportation tariffs.

d. Commission Conclusion

The Commission recognizes the value of imbalance trading to transportation customers. But given the adoption of gas banking services above, the Commission does not believe that imbalance trading is necessary under the circumstances. If circumstances change in future AIU rate cases, the Commission will again consider requiring imbalance trading.

13. Purchase/Confiscation of Customer-Owned Gas

a. AIU's Position

AIU's existing tariffs provide AIU the right to purchase gas owned by transportation customers in a situation where system integrity is threatened and the system emergency requires curtailment. AIU proposes similar language in its proposed Rider T. Under its proposal, AIU would first attempt to acquire the transportation

customer gas through a voluntary purchase. If a voluntary purchase does not occur, proposed Rider T provides that AIU may confiscate the gas at price of 110% of the daily market price.

While CNE-Gas understands that AIU may need to acquire customer-owned gas in an emergency, it is still troubled by the idea of a forced sale of transportation gas even if a 10% premium is included. To address such concerns, AIU's current proposal contains three conditions that must be met before AIU has the right to purchase gas owned by transportation customers. First, system integrity is threatened. Second, the utility has declared a Critical Day. Third, the utility implements curtailment of natural gas service to customers pursuant to the Curtailment Plan. AIU contends that these conditions ensure that it will not arbitrarily acquire gas from its transportation customers without good reason and will exercise this right only under the most severe circumstances. AIU states further that the right to purchase gas owned by transportation customers would not be allowed only on a critical day since all three conditions must be met before purchasing customer gas. In addition, the proposed tariff states —the Company's right to purchase gas owned by a Customer shall be exercised by the Company only after the Company has exhausted reasonable efforts to obtain the necessary gas supplies from other sources" (Ameren Ex. 30.0 at 30-31)

In response to CNE-Gas' assertion that involuntary confiscation of transportation gas supplies will not increase the volume of gas that is flowing during a curtailment, and therefore no relief will be provided, AIU asserts that CNE-Gas misunderstands how the process works. AIU witness Glaeser explains that volumes of gas delivered into the system during a curtailment will likely not be increased by confiscation; however, the needed relief is still provided. The gas purchases only occur during curtailment, during which customers will be required to reduce usage by customer class so that the demand on the system will be lower. The gas purchased from the transportation customers at the city gate delivery points will be then used to serve high priority residential and human needs customers, since the larger customers will have been curtailed.

If confiscation occurs, CNE-Gas argues that AIU should waive any balancing costs or penalties incurred due to any imbalance created when transportation customer gas is purchased during curtailment. AIU does not agree and argues that if a customer is complying with the curtailment, the imbalance will be minimized. AIU states that it would not buy any gas from transportation customers unless they have been curtailed, which means their usage has been reduced. If there is more than a minimal imbalance, AIU maintains that the customer has not complied with the curtailment and should incur all imbalance charges as well as penalties. If these costs and penalties are waived, AIU asserts that there is no incentive to a customer to reduce its usage, thereby defeating the purpose of the curtailment and thus threatening system integrity.

In response to any suggestion that confiscation of gas, even with a 10% premium, constitutes a conversion under 810 ILCS 5/7-404, AIU argues in its Reply Brief that this section of the Illinois statutes is inapplicable to that situation. Moreover, if

such tariffs are approved by the Commission, AIU asserts that it would be difficult to claim that the tariffs are unfair since it is the Commission that determines what is fair in this proceeding. Taking the CNE-Gas position regarding conversion to its logical extreme, AIU contends that no gas utility could ever curtail or interrupt a transportation customer no matter what the circumstance. AIU also does not see the relevance of CNE-Gas' FERC discussion.

b. Staff's Position

AIU initially sought the right to purchase customer gas at market price on a critical day. Staff witness Sackett objects to this because he believes that AIU should attempt to purchase gas from transportation customers in voluntary transactions before confiscating gas from customers. CNE-Gas proposes that, at a minimum, a 10% premium be applied to the market price for that purchase. Mr. Glaeser then proposed a voluntary purchase offer first, and then confiscation at a 10% premium over the market price. Mr. Sackett accepts this proposal.

c. CNE-Gas' Position

CNE-Gas objects to any forced sale of customer-owned gas, no matter the circumstances. Confiscation of customer-owned gas, CNE-Gas opines, would likely constitute conversion under Illinois law. CNE-Gas reports that Section 7-404 of the Uniform Commercial Code (adopted as 810 ILCS 5/7-404 (2008) in Illinois) states that a bailee is not liable for delivering goods to a person who did not have authority to receive the goods if the bailee acts in good faith. However, the commentary to the provision states that "[g]ood faith now means 'honesty in fact and the observance of reasonable commercial standards of fair dealing,'" UCC §7-404 cmt. purposes (2007). CNE-Gas contends that AIU's confiscation of customer-owned gas would be unlikely to be considered good faith under this standard because AIU would have knowledge that the supplier did not wish to sell the gas to AIU. (See Bishop v. Allied Van Lines 3 Dist., Inc., 399 N.E.2d 698, 701 (Ill. Ct. App. 1980) (holding that a bailee did not act in good faith and did not observe commercially reasonable standards when the bailee delivered the goods with knowledge of adverse claims between the bailors)).

Similarly, CNE-Gas states that FERC has required interstate pipeline tariff provisions that provide for the seizure of gas by the pipeline to be removed from tariffs if a customer fails to abide by a curtailment or interruption notice. (See, e.g., Guardian Pipeline, L.L.C., 91 FERC ¶61,285 at 61,987 (2000); TriState Pipeline, L.L.C., 88 FERC ¶61,328 at 62,006 (1999); Steuben Gas Storage Company, 72 FERC ¶61,102 at 61,543 (1995))

CNE-Gas also argues that because AIU does not propose to waive penalties for actions taken by transportation customers in support of a curtailment order, the confiscation of customer-owned gas supply leaves the transportation customer at risk of receiving a price of only 90% of index if it delivers excess supply, while nominated volumes are sold to the utility at 110% of index, even though both actions alleviate the

curtailment. Even at the 110% index price, CNE-Gas states that transportation customers could be forced to sell gas to the utility at a financial loss, depending on the purchase price, which may not be index-based. As the daily market price is based upon the price that gas traded at the morning prior to flow, CNE-Gas contends that it is likely that by the time the Critical Day takes effect, as no advance notice must be provided, the daily market price from the previous day is no longer representative of the market price at that point in time when the gas is seized. The mechanics of this ultimately depend upon the exact storage, cashout, and balancing tariffs approved in this proceeding and since no draft tariffs exist for any of the current proposals offered, CNE-Gas simply requests that if the Commission approves the confiscation of the customer's gas supply, the customer should not be assessed any charges or penalties due to any positive imbalance that is created following a forced sale.

CNE-Gas states further that transportation customers and their suppliers may also have the option to secure additional gas supply. AIU's proposed tariff, CNE-Gas complains, does not accommodate such action. Instead such action could be met with additional costs and penalties from AIU, even though additional gas supplies on a Critical Day is precisely the outcome AIU desires. Consequently, if AIU's proposal is approved, CNE-Gas asserts that transportation customers should not be penalized or charged for delivering additional gas supplies under such circumstances. CNE-Gas urges the Commission to require waiver of such additional costs.

d. Commission Conclusion

At the outset, the Commission must state that it does not anticipate that AIU will often need to purchase or confiscate gas owned by transportation customers in order to preserve system integrity. In a well maintained and managed system, such circumstances should occur infrequently. Purchasing or confiscating customer-owned gas should be, and appears to be, viewed by AIU as a last resort to stave off an emergency.

The less extreme of the two options for avoiding an emergency is obviously a voluntary purchase. The Commission agrees with and approves of the notion that AIU should first attempt to negotiate a price for customer-owned gas that it seeks to acquire. In the event that a voluntary purchase can not be negotiated, the Commission also agrees that AIU should be able to confiscate customer-owned gas under reasonable terms in order to prevent harm to the gas distribution system. The Commission has considered CNE-Gas' claim that confiscation of customer-owned gas violates Section 7-404 of the Uniform Commercial Code, but does not find this statute applicable.

If AIU is permitted to purchase customer owned gas, CNE-Gas also argues that the transportation customer should not be penalized for any imbalances resulting from the associated curtailment. The Commission agrees with CNE-Gas to the extent that the imbalance is one where the transportation customer delivers more gas into the system than is used for this is exactly what a struggling system needs. If a transportation customer uses more gas than it delivers into the system, then the

imbalance penalties should apply. As for the price of confiscated gas, the Commission is concerned that paying the transportation customer the market price of gas traded at the morning prior to flow may not be reasonable. If circumstances are such that curtailment and a Critical Day are occurring, the market price of gas may be quite higher than what it was the morning prior to flow. Therefore, the Commission concludes that the price to be paid for confiscated gas should be equal to the 8:00 AM index price reported by Platt's *Gas Daily* Midpoint for Chicago Citygates on the Critical Day. A 10% premium shall be added, as agreed to by AIU. This result should address transportation customers' concerns about receiving a fair price for confiscated gas.

14. Critical Day and Operational Flow Order Notice Provisions

a. AIU's Position

AIU proposes to include both Critical Day and OFO language in gas tariffs. AIU witness Glaeser explains that an OFO is an order which the utility may declare or issue to a customer group or to specific customers in order to alleviate problematic operating conditions. He also indicates that the new Rider T includes the Critical Day declarations. Mr. Glaeser identifies a number of circumstances that could cause the declaration of a Critical Day. The —common driver” is that on-system or up-stream resources used to operate and maintain system integrity are under duress, threatening the integrity of the distribution system and the ability to deliver gas to all customers. AIU states that OFOs and Critical Day provisions are common place in the natural gas industry, including the interstate pipelines to which AIU is connected, and are necessary to ensure the integrity of the delivery system. AIU proposes that transportation customers be notified of an OFO or Critical Day through formal notification such as telephone, fax, or e-mail. The utility would also post such a declaration on its USMS website, which is utilized by transportation customers and their marketers for routine operations. Mr. Glaeser also identifies the various penalties and charges that would be issued in the event an OFO or Critical Day was violated. He explains that a series of tiered penalty charges tied to the severity of the event are being proposed and identified the three penalty charges as: OFO Balancing Charge, Unauthorized Gas Use Charge, and Critical Day Imbalance Charge. Mr. Glaeser also testifies as to the manner by which these charges would be assessed.

AIU notes that only CNE-Gas responds to AIU's OFO and Critical Day positions. Specifically, CNE-Gas is concerned with the lack of no advance notification requirements and argues that some parameters should be placed in the tariff to provide guidance for the type of advanced notice that the utilities will provide to the transportation customers and their suppliers. In response, Mr. Glaeser testifies that AIU is willing to provide a 2-hour prior notice before implementing an OFO against any customer or group of customers. He also testifies that as much notice as practical would be given to customers in the event of a Critical Day but that a defined time frame could not be provided due to the unexpected nature of the events that lead to a Critical Day declaration. As an example, Mr. Glaeser observes that a pipeline rupture foregoes any meaningful opportunity for an extended notice. He concludes nonetheless, that it is

in AIU's best interest to give as much notice as practicable since the purpose is to notify transportation customers to modify their supply deliveries and/or gas consumption to help maintain system integrity.

AIU notes that CNE-Gas disagrees that 2 hours is sufficient and asserts that Nicor provides notification of a Critical Day at least 25 hours in advance and Peoples provides 23½ hours notice. CNE-Gas is perplexed as to why AIU can only provide 2 hours notice of an OFO and no commitment to advance notification for a Critical Day. To facilitate understanding of AIU's position, Mr. Glaeser proffers an example that demonstrates the concerns to committing to more than the 2-hour notice for an OFO and no prior notice period for a Critical Day. The AmerenCIPS Metro-East system distributes natural gas to Alton, Illinois and adjacent areas. This captive system serves approximately 18,000 customers and is connected to one interstate pipeline – Mississippi River Transmission Corporation – through the Federal Station and Chesson Lane Interconnections. The AmerenCIPS Metro-East system has no on-system storage. If the Federal Station interconnect facility experienced a pipeline rupture on a normal winter day, all 18,000 customers on the system would rapidly lose pressure within minutes. This would happen because Chesson Lane is a significantly smaller interconnect and can not supply the entire AmerenCIPS Metro-East system under normal winter load conditions. By issuing an immediate Critical Day and quickly implementing curtailment procedures, the system could be protected from a widespread outage by curtailing the largest customers before the entire system collapsed. The Chesson Lane station may be able to maintain system deliveries and pressure if the major industrial customers on the system shut down quickly. AIU argues that it is not practical to give any notice in this emergency situation to maintain system integrity – much less 24-hours' notice. AIU insists that it is, therefore, essential that it has the ability to issue a Critical Day without advance notice.

Of course, as stated in the tariff, AIU indicates that it will provide advance notification if possible, but providing advance notice may not be practical or even possible in certain situations. AIU asserts that the tariffs should reflect operational realities--and the reality is that advance notification can not always be given when a system emergency occurs. AIU maintains that CNE-Gas inaccurately compare AIU's notification period to Nicor and Peoples. Although all utilities could have ruptures on their systems, AIU contends that there may be differences in the resources available to recover from pipeline ruptures. AIU states that some utilities may have hub services readily available, while others may have fully integrated systems – unlike AIU, which has many isolated, captive systems (See Ameren Ex. 54.7, Ameren Illinois Natural Gas Facilities map). AIU speculates that even Nicor's or People's more integrated distribution systems or hub service resources could experience major failures leading to a more immediate crisis than the their tariff language implies. AIU reasons that the different resources available to respond to a system emergency may make the notification period different.

b. CNE-Gas' Position

When declaring an OFO or Critical Day, CNE-Gas argues that the Commission should require AIU to provide reasonable notice. CNE-Gas does not agree that 2 hours notice for OFOs is sufficient and contends that no notice for Critical Days is unacceptable. Certainly if force majeure conditions occur, CNE-Gas acknowledges that the standard notice intervals may require suspension due to extreme circumstances. However, under other OFO and Critical Day circumstances, CNE-Gas argues that transportation customers and their suppliers should receive adequate notification before such a —~~on~~—force majeure” event is declared by an LDC. CNE-Gas contends that transportation customers deserve some degree of commitment from a utility that it will attempt to notify them in advance when these conditions occur so the transporter is able to take appropriate action to mitigate potential costs which may be incurred as a result of a Critical Day or OFO. CNE-Gas asserts that the rationale AIU offers for its inability to provide any Critical Day notice is no different than conditions that confront other utilities that offer notice. As discussed above, CNE-Gas observes that other Illinois utilities provide notice more than twenty hours in advance. CNE-Gas recommends that the Commission require AIU to provide OFO and Critical Day notice to customers that is comparable to the terms provided by other Illinois utilities.

c. Commission Conclusion

The Commission agrees with CNE-Gas that when comparing the notice provided by Nicor and Peoples and the notice that AIU proposes to provide, a great disparity seems to exist. A review of Ameren Ex. 54.7, however, appears to explain at least in part why AIU may not be able provide much notice in some isolated areas of its gas distribution systems. Clearly, there are multiple communities served by AIU which are connected to only one interstate gas pipeline. Under such circumstances, the unexpected loss of supply from the interstate pipeline could endanger system integrity so quickly that the amount of notice that CNE-Gas appears to be contemplating would not be feasible.

Other portions of AIU's distribution systems, however, may be well suited to the provisioning of additional notice by AIU before declaring an OFO or Critical Day. Such areas include where storage resources exist and/or there are multiple interconnections with interstate pipelines. While accepting AIU's OFO and Critical Day notice provisions for purposes of this proceeding, the Commission directs AIU to provide in its next gas rate case filing an analysis of its distribution systems identifying those areas that would not be immediately affected by a single event on the associated interstate pipeline(s). The analysis must also address with specifics whether AIU could provide notice in such areas comparable to the notice provided by Nicor and Peoples.

One other area of concern regards AIU's proposed Critical Day definition in Rider T. The fifth condition that may trigger a Critical Day under Rider T is "other market conditions which may warrant such action by the Company." Exactly what "market conditions" may warrant declaration of a Critical Day is unclear to the Commission. The

tariffs of Nicor and Peoples do not appear to share this language. The Commission advises AIU to be cautious in the declaration of Critical Days for market reasons at least until it provides clarification in its next gas rate cases. In any event, the Commission expects AIU to only implement OFOs and Critical Days as last resorts in protecting system integrity.

15. AmerenCIPS and AmerenCIPS Metro-East Rate Areas

Currently, AmerenCIPS has two rate areas, AmerenCIPS and AmerenCIPS Metro-East. In its direct filing, AIU witness Warwick proposed to establish one set of gas tariffs for the entire AmerenCIPS footprint instead of the two current rate areas. Staff witness Harden objects to consolidating these service areas due to the unequal bill impacts for individual gas customers that could result from this change. Mr. Warwick later stated a willingness to accept the Staff position. He notes, however, that the rate conformance would bring about a rate reduction for certain customers under AIU's proposed rates and rate design. While AmerenCIPS agrees to forego rate consolidation at this time, AIU plans to raise the issue again in AmerenCIPS' next gas rate case consistent with Ms. Harden's comments.

The Commission acknowledges AIU's acceptance of Staff's position on this issue, but is nevertheless reluctant to adopt it in light of observations made by AIU in its Brief on Exceptions. AIU does not mean to suggest in its Brief on Exceptions that it is changing its position following its acquiescence to Ms. Harden's concerns, but simply wants to make the Commission aware of the impact on GDS-1 and GDS-2 customers in the AmerenCIPS and AmerenCIPS Metro-East rate areas if the customer charge is to reflect 80% of fixed costs. Using its August 22, 2008, supplemental response to the Administrative Law Judges' post-record data request, AIU explains that the monthly customer charge for GDS-1 AmerenCIPS customers would be \$18.03, while the corresponding charge for AmerenCIPS Metro-East customers would be \$22.01. If these rate areas are combined, AIU reports that the single GDS-1 monthly customer charge would be \$18.43. AIU states further that the monthly customer charge for GDS-2 customers of AmerenCIPS would be \$28.10 while that of AmerenCIPS Metro-East would be \$56.71. Under a combined rate area, AIU states that the single GDS-2 monthly customer charge would be \$29.97.

Even though these charges are somewhat different from those approved in this Order, the Commission is of the opinion that such disparities (particularly for GDS-2 customers) should be avoided when the means to do so is so readily available. Accordingly, for the purpose of the monthly gas customer charge, the AmerenCIPS and AmerenCIPS Metro-East rate areas should be combined for the GDS-1 and GDS-2 rate classes. The fact that these rate areas are to be eventually combined anyway further supports this conclusion.

E. Contested Electric Issues

1. Rate Limiter

a. AIU's Position

AIU recommends that the rate limiters implemented as part of the rate redesign case, Docket No. 07-0165, be modified or eliminated. AIU says that as a result of the rate redesign case, rate limiter provisions were added to DS-3 and DS-4. The total monthly charge for Distribution Delivery and Transformation Charges was limited to no more than 2¢/kWh where 20% or less of the customer's annual usage occurs in the summer months of June through September. The Distribution Delivery Charges for DS-3 and DS-4 were also increased, to maintain revenue neutrality. AIU indicates that Staff and GFA want to maintain the DS-4 rate limiter. AIU complains that neither GFA nor Staff offers an analysis of how much longer these limiters should persist.

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. According to AIU, the Commission expected that the parties would, in the instant rate case, be evaluating the period of time the rate limiter needs to be in place to ensure just and reasonable rates.

AIU has proposed moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU asserts that the GFA essentially asks to retain rate design concessions that, when combined with the move to on-peak demand determinates, would establish benefits for GFA constituents above and beyond those awarded in Docket No. 07-0165. AIU believes eliminating the DS-4 rate limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU contends that implementation of a rate limiter requires that Distribution Delivery Charges be increased for DS-3 and DS-4 customers. In other words, AIU says Distribution Delivery Charges are higher than they otherwise would be if there was no rate limiter. AIU claims that customers who do not benefit from the rate limiter subsidize customers who receive a benefit. AIU says eliminating the DS-4 rate limiter eliminates this inequity.

According to AIU, IIEC points out that there is no particular distinction for the customer group GFA singles out that warrants a long-standing subsidy. AIU indicates that the Commercial Group offers three reasons for eliminating the rate limiter. The Commercial Group claims that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment; rather it puts all customers within that class on a more equal footing with respect to rates being based on the true cost to serve. The Commercial Group also asserts that in Docket No. 07-0165 the Commission made it clear that the rate limiter is a transitional mechanism for certain customers who were facing large rate increases and that it should only be in place as long as necessary. The Commercial Group also contends that use of on-peak demand

provides an incentive for rate limiter customers to reduce on-peak demands and potentially reduce their bills.

In AIU's view, the move toward on-peak demand determinates should be considered in evaluating the continued need for a DS-4 limiter. AIU proposes to begin using a billing demand applicable to the Distribution Delivery Charge equal to the higher of (a) the maximum on-peak demand in the month and (b) 50% of the highest off-peak demand in the month. Presently, the Distribution Delivery Charge is assessed based on a customer's monthly maximum demand (e.g., highest demand occurring in the billing month regardless of when it occurs). AIU says the aggregate impact of the proposed on-peak demand method is slight: proposed billing demands are slightly lower than present billing demands, where present demands are based on a customer's maximum demand regardless of when it occurs during the billing month. AIU states that for AmerenIP, AmerenCIPS, and AmerenCILCO, proposed billing demands are 97.8%, 96.3%, and 94.2%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands are 98.2%, 96.7%, and 98.4% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively. AIU claims that if only the on-peak demand is used, and the floor amount of 50% of the customer's off-peak demand ignored, the impact would be very small. For AmerenIP, AmerenCIPS, and AmerenCILCO, AIU says the proposed billing demands would be 97.7%, 95.5%, and 92.6%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands would be 98.2%, 96.0%, and 98.2% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively.

AIU argues that changing to an on-peak demand method empowers rate limiter customers to shift demands to the off-peak period and thus reduce the demand charge component of their bills. AIU believes that retaining the rate limiter mitigates the price signal for customers subject to the rate limit to shift to the off-peak period. AIU states that while Staff is correct that there are potential benefits to both customers and AIU by encouraging customers to shift use toward the off-peak period, the change to billing demand will be most effective without a rate limiter in place.

AIU says the change to an on-peak demand method was actually advocated by IIEC in the previous delivery services cases and the Commission adopted IIEC's recommendation requiring AIU to provide data to allow a rate impact comparison between the existing methods and the on-peak method in the next delivery services case. AIU says that while it acknowledges the support Mr. Lazare and Mr. Adkisson provide for this change to an on-peak method, AIU believes this support undermines their position regarding the DS-4 rate limiter. AIU says a common theme in Staff's and the GFA's position is the perceived disproportionate impact that a segment of customers would face.

AIU indicates that GFA further argues for seasonal rate differentiation. Mr. Adkisson states there is not sufficient evidence for the Commission to determine the appropriateness of and level of a seasonal differential in delivery rates based on examining the 12 grain drying customers; however AIU believes this is only partially

accurate. AIU agrees with Mr. Adkisson that there is insufficient evidence to set the level of a seasonal differential in delivery rates; however, AIU claims there is sufficient evidence to suggest that a majority of the 12 DS-4 grain-drying customers should pay a premium for primary voltage facilities. AIU says all DS-4 rate limiter grain drying customers are served from a primary supply line voltage (less than 15 kilovolt).

AIU states that all DS-4 customers have peak demands over 1,000 kW. According to AIU, these customers' demands are often large enough relative to all other customers on the circuit to drive the coincident peak to the fall grain drying season. AIU asserts that seasonal rate would not provide a lower price for these customers. AIU says an examination of circuits serving smaller (DS-3) customers eligible for the rate limiter has not yet been conducted. Until such analysis has been conducted, AIU claims it is unknown if demands contributed by DS-3 grain drying customers cause the circuit to peak in the fall. As a result, AIU suggests increasing the DS-3 rate limiter by an amount equal to the class average rate increase. AIU believes, however, that there is sufficient evidence in the record that the rate limiter affording to certain DS-4 customers should be eliminated.

AIU states that the Distribution Delivery Charge is based on a monthly demand and if a customer does not establish a demand during the monthly billing period, it will not pay a Distribution Delivery Charge in the month. AIU adds most grain drying customers set relatively large demands in 2 or 3 fall billing periods, and small demands in the remaining 9 or 10 billing periods. Thus, AIU says these grain drying DS-4 customers pay relatively small amounts of revenue in 9 or 10 billing periods and larger amounts in 2 or 3 monthly billing periods. According to AIU, most other DS-4 customers have relatively consistent usage, and thus a consistent revenue pattern, throughout the year.

AIU states that of the 12 grain drying rate limiter customers considered in this proceeding, 8 are served from a circuit and/or substation transformer with a fall peak, 2 customers are served from circuits and/or substation transformers that show equivalent peaks in both the summer and the fall, and 2 customers are served from the same substation with a peak occurring in the summer. AIU contends that customers or groups of customers contributing to the peak placed on distribution facilities, such as many of these grain dryers, should pay more of the cost for the system.

According to AIU, a review of the circuits serving DS-4 grain drying customers eligible for the rate limiter shows that the peak for those circuits is driven predominantly by customer demands occurring in the fall. In AIU's view, the rate limiter provides a subsidy to these seasonal customers at the expense of other DS-4 customers. AIU states that, assuming a DS-4 limiter of 2.82¢/kWh, 2.31¢/kWh, and 2.17¢/kWh, for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively, grain drying customers would experience a benefit equivalent to just under 0.45¢/kWh. AIU adds that, assuming an average price per kWh paid of 9¢/kWh, the rate limiter would reduce the overall energy costs for a grain drying customer by about 5%.

AIU contends that DS-4 rate limiter customers drive the peak and costs on most distribution circuits, yet pay a relatively small amount toward those costs compared to non-grain drying customers. If the Commission finds the DS-4 limiter is still appropriate, but would like to begin the process of reducing reliance on the subsidy and set the rate at 3¢/kWh as AIU originally proposed for DS-3, AIU claims rate limitation reductions to class revenue would need to be reflected in AIU's proposed jurisdictional operating revenue. AIU says these values are provided in the third table on Ameren Ex. 26.1. AIU indicates that if the Commission instead chooses to simply increase the existing 2¢/kWh rate limiter by the average DS-4 rate increase for each AIU, the corresponding limited revenue amount are also shown within the third table of Ameren Ex. 26.1.

b. GFA's Position

GFA claims that its members suffered rate shock when the rates imposed in 2006 were implemented. Commission approval of the DS-3 and DS-4 rate limiters, however, helped to mitigate the impact of triple digit percentage rate increases for grain dryers and seasonal use customers. GFA says that customers that limit their total kWh usage during the four summer billing periods of June through September to 20% or less of their annual kWh consumption qualify and may be eligible for the rate limiter. The rate limiter is calculated each billing period for qualifying customers by adding the individual customer's monthly Distribution Delivery Charge and Transformation Charge revenues and dividing the sum by the customer's total kWh for that billing period. GFA states that if the combined charge is greater than 2¢/kWh, a credit for the amount over 2¢/kWh will be applied to the customer's bill. GFA indicates that the rate limiter limits the average monthly cost of the Distribution Delivery Charge and the Transformation Charge to 2¢/kWh, which is several times higher than the previous and current class average ¢/kWh, but can be less than what an individual customer would have otherwise paid. GFA notes that the rate limiter is not applicable to Customer, Meter, Transmission, Reactive or Power and Energy charges.

GFA indicates that the DS-3 and DS-4 tariffs with the rate limiter became effective October 19, 2007 and less than three weeks later, on November 2, 2007, AIU filed these rate cases. GFA says that AIU proposes to totally eliminate the DS-4 rate limiter, which would allow an unlimited increase for DS-4 customers and initially proposed a 50% increase to the DS-3 rate limiter, from 2¢/kWh to 3¢/kWh. GFA states that in its rebuttal testimony, AIU agrees to support an increase to the DS-3 rate limiter equal to the class average increase. For the purpose of this rate case, GFA indicates it will no longer object to such an increase; however, GFA continues to oppose the proposal to eliminate the DS-4 rate limiter. In GFA's view, it is simply too soon to eliminate the rate limiter.

GFA states that AIU has recommended across-the-board increases on its rates, with the exception of the rate limiter. GFA contends that AIU's proposal is unfair and would effectively undo the Commission's Order in Docket No. 07-0165. According to GFA, if the Commission raises AIU's rates across the board, then the rate limiter should receive that same treatment.

GFA says that if, in the next rate case, AIU bases its proposed rates on a class COSS, then the Commission will have the opportunity to review and reconsider all aspects of rate design, including the rate limiters. Additionally, GFA suggests that all parties will be able to voice their respective concerns and opinions regarding the rate limiters, seasonal rates, and other rate design features. GFA asserts that if the rate limiter is to be modified or eliminated, it should be done in conjunction with a COSS, where all factors can be considered.

In its Reply Brief, GFA says it has not ignored the Commission's direction in Docket No. 07-0165, and says it has performed the evaluation requested by the Commission. GFA claims that for a number of reasons, it and Staff determined that the most reasonable course of action is for the Commission to apply to the rate limiter the same across-the-board increases that are being applied to other rate components. While the Commission stated its desire to have the parties reevaluate the rate limiter, GFA argues there is nothing in its Order indicating its knowledge that AIU would file a rate case less than three weeks after implementation of the rate limiter, seeking to eliminate the rate limiter. GFA also says nothing in the Order indicates that the Commission anticipated an across-the-board increase rather than a full review of a class COSS and cost-based rate design.

AIU argues that its proposal to move to an on-peak determinant for establishing demand rates obviates the need for the rate limiter. GFA states that even if DS-4 customers were able to shift on-peak load to off-peak period and totally capture the prospective benefits of the proposed change in billing demand determination, the resulting benefits pale in comparison to the triple digit increases grain dryers will experience without the DS-4 rate limiter.

GFA proposes seasonal delivery rates while AIU argues against seasonal rates. According to GFA, AIU ultimately, takes the position that a proposal to implement seasonal delivery rates is not appropriate at this time and requires further analysis. GFA agrees that further analysis should take place, therefore, it recommends that the Commission order AIU to begin collecting data necessary for determining seasonal delivery rates and to provide those data to the Commission and other parties prior to filing its next electric rate case.

c. Staff's Position

Staff says that while AIU generally accepts the across-the-board approach to increasing existing rates, AIU continues to recommend that the rate limiter for the DS-4 class be eliminated. AIU argues that the peak for these customers is driven by demands during the fall season which suggests that customers under the rate limiter are being subsidized by others within the class. AIU also suggests the limiter would not have a significant effect on grain drying customers, reducing their overall energy costs by about 5%. AIU also presents the option of setting the limiter for DS-4 customers at 3¢/kWh as it originally proposed for DS-3.

Staff says that since it and AIU agree that bill impacts are the preeminent concern, it does not make sense to base rates for the large majority of customers on bill impacts while setting rates for a small number of customers receiving the rate limiter according to costs. Staff asserts that those latter customers can rightly complain of being held to one standard for ratemaking when other customers are held to another standard. In Staff's view, the only reasonable approach in this difficult ratemaking environment is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes.

d. IIEC's Position

IIEC takes no position on the extension of the rate limiter for DS-3 customers; however, it opposes the extension for DS-4 customers. IIEC states that grain dryers and seasonal use customers are not the only customer classes that experienced large increases in delivery service rates. According to IIEC, some DS-4 customers other than grain dryers or seasonal use customers experienced rate increases of over 200% in AIU's last delivery service case. IIEC says other customer classes also experienced significant rate increases in going from the 2006 rates to the 2007 rates. In IIEC's view, there is no basis for a continued distinction between these customers and the customer group represented by GFA, especially where it establishes a continuing subsidy. IIEC asserts that GFA has not demonstrated why these particular DS-4 customers should be entitled to the continuing benefits of the rate limiter while other DS-4 customers do not enjoy rate mitigation.

GFA argues that the rate limiter has not been in effect long enough and points out that AIU filed this rate case three weeks after the rate limiter took effect. According to IIEC, GFA ignores the fact that the rate limiter for DS-4 grain drying customers will have been in place for almost one year by the time the rates approved in this case take effect. IIEC believes that under such circumstances, there is no justification for continuation of the rate limiter for DS-4 grain drying customers. In response to GFA's suggestion that the rate limiter should only be eliminated in conjunction with a COSS, IIEC points out that a COSS is available in this proceeding.

IIEC notes that Staff has concluded that elimination of the rate limiter would result in grain drying customers, such as the DS-4 grain drying customers, being held to one standard for ratemaking when other customers are held to another standard. IIEC argues that Staff has it exactly backwards. According to IIEC, the rate limiter for DS-4 customers, who happen to be grain dryers, does result in one standard being applied to those customers while another standard is applied to other DS-4 customers who have also experienced rate shock, but who do not benefit from the rate limiter.

e. Commercial Group's Position

According to the Commercial Group, given that the rate limiter subsidies must be collected only from DS-3 and DS-4 customers, phasing out the rate limiter would relieve

the stresses on the DS-3 and DS-4 customers who are required to provide both intra-class subsidies to the customers taking advantage of the rate limiter and interclass subsidies to other classes. The Commercial Group believes this is an unfair burden that should be eliminated.

The Commercial Group disagrees with Staff that elimination of the rate limiter is inconsistent ratemaking that singles out one group of customers for unequal treatment. The Commercial Group argues that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment. In the Commercial Group's view, it puts all customers within that rate class on a more equal footing with respect to their rates being based on the true cost to serve. The Commercial Group insists that it is unequal for certain customers in a class to subsidize other customers in the class, particularly where the subsidized customers' rates are already below cost before the rate limiter is applied. The Commercial Group believes the rate limiter has served its limited transitional purpose and should be eliminated. If it is not completely eliminated in this case, the Commercial Group submits that the rate limiter should be phased out and eliminated as AIU proposed in its direct testimony.

The Commercial Group agrees with AIU and IIEC that the DS-4 rate limiter should be eliminated. The Commercial Group also urges the Commission to eliminate the DS-3 rate limiter. According to the Commercial Group, there is even more reason to do so, because DS-3 rates for AIU are already significantly above cost. The Commercial Group submits that with the rates of grain customers being below cost even before the rate limiter is applied, the rest of the DS-3 class is subsidizing not only other rate classes, but other ratepayers within the class. The Commercial Group claims that this double subsidy stresses DS-3 customers who are concerned with the impact of increasing electric bills on operations at schools, retail facilities, and industrial facilities.

f. Commission Conclusion

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. AIU also proposes moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU believes eliminating the DS-4 Rate Limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU adds that customers who do not benefit from the rate limiter subsidize customers who receive a benefit.

For purposes of this proceeding, GFA does not oppose an increase to the DS-3 rate limiter equal to the class average increase. GFA continues to oppose the proposal to eliminate the DS-4 rate limiter because it believes it is too soon to eliminate that benefit. In Staff's view, the only reasonable approach is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes. IIEC takes no position on the extension of the limiter in this

case for DS-3 customers; however, IIEC opposes the extension of the rate limiter for DS-4 customers. The Commercial Group advocates eliminating the rate limiter for both DS-3 and DS-4 classes.

As the parties are well aware, the Commission generally favors rates that reflect the cost of service. The Commission, however, is keenly aware that its rate decisions can have adverse impacts on some customers if extreme care is not exercised. The Commission is especially intent on avoiding the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if Staff's proposal to apply an across-the-board increase to the existing rate limiters for both DS-3 and DS-4 classes is adopted. The Commission is committed to eliminating these rate limiters at the earliest opportunity; however, the Commission concludes that the time to do so has not yet arrived.

2. Street Lighting

a. AIU's Position

AIU states that it and LGI concur on certain municipal street-lighting issues. AIU says it provided a detailed COSS, contained in Schedule E-6, for the current rate cases and will provide a similar COSS in the next set of rate cases, along with the requested lighting rate design study aimed at determining cost-based lighting fixture charges. With regard to LGI's street light fixture rate proposal, AIU disagrees with LGI's proposed approach.

For the purpose of this case, LGI recommends capping AmerenIP street light fixture rates, and that the resulting reductions to AmerenIP's filed revenue requirement related to street lighting be passed along to all delivery service customer classes. AIU notes that LGI only represents municipalities within the AmerenIP service territory.

AIU provides the following tables to demonstrate the street lighting proposals advanced by the AIU and LGI:

Average Cost per Month per Fixture

Municipality	Existing Rates	AIU Proposal		LGI Proposal	
		Monthly Price	Change	Incremental Change	Monthly Price
Champaign	\$ 8.66	\$ 12.64	\$ 3.98	\$ 1.29	\$ 9.95
Bloomington	\$ 8.03	\$ 11.72	\$ 3.69	\$ 1.20	\$ 9.23
Normal	\$ 8.07	\$ 11.78	\$ 3.71	\$ 1.20	\$ 9.27
Urbana	\$ 8.50	\$ 12.33	\$ 3.83	\$ 1.17	\$ 9.67
Decatur	\$ 7.81	\$ 11.40	\$ 3.59	\$ 1.16	\$ 8.97

Per Capita Average Cost per Month

Municipality	Existing Rates	AIU Proposal		LGI Proposal	
		Monthly Price	Change	Incremental Change	Monthly Price
Champaign	\$ 0.17	\$ 0.24	\$ 0.07	\$ 0.02	\$0.19
Bloomington	\$ 0.49	\$ 0.71	\$ 0.22	\$ 0.07	\$0.56
Normal	\$ 0.36	\$ 0.52	\$ 0.16	\$ 0.05	\$0.41
Urbana	\$ -	\$ -	\$ -	\$ -	\$ -
Decatur	\$ 0.86	\$ 1.26	\$ 0.40	\$ 0.13	\$0.99

According to AIU, LGI witness Hughes proposes to cap the fixture rates increase in the AmerenIP service territory by no higher than 14.89%. AIU states that the proposed DS-5 class provides customers with dusk-to-dawn photo cell-controlled lighting service. AIU adds that while it will typically own and maintain the lighting fixture, DS-5 will provide for customers who own their own lighting facilities as well.

AIU indicates that LGI only addresses the charges for fixtures. AIU indicates that the fixture charges in DS-5 do not cover power and energy charges, transmission charges, or delivery-service charges. To achieve the targeted revenue requirement for each class, AIU proposed fixture charges laid out in Ameren Ex. 12.7E. AIU proposes to adjust those charges on an equal percentage basis unique to each utility. AIU states that transmission and energy charges are charged separately through Rider TS and Rider BGS, and distribution delivery charges are assessed through a separate component within DS-5.

According to AIU, Ms. Hughes proposes that AmerenIP's fixture charges be capped based on the incremental costs of fixtures calculated several years ago for use in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and recommends funding this cap by shifting costs to other rate classes. In AIU's view, Ms. Hughes' case for carving out an exception to the across-the-board increase is not persuasive. AIU complains that Ms. Hughes does not clarify why AIU's DS-5 class, and that class alone, should be allowed use of a non-across-the-board revenue allocation method, while other classes are held to an across-the-board approach. AIU also says that Ms. Hughes fails to extend the concept of incremental-cost pricing to AmerenCIPS and AmerenCILCO. AIU argues that LGI customers have the option of choosing to purchase their own street lighting fixture and avoid AmerenIP's fixture rates all together, while other delivery service customers have no service choice. AIU insists that it is unfair to shift an amount potentially in excess of \$5 million dollars from charges that certain customers pay by choice to other customers, including residential customers.

In its Reply Brief, AIU says it does not think it is appropriate to shift revenues between classes in a manner that would disturb the intended purpose of the rate redesign docket. In particular, AIU claims it would not be appropriate to shift revenue recovery between classes in a manner that creates impacts for residential and small business customers. AIU argues that the revenue impacts associated with a

realignment of rates to more closely match class cost of service indicators would result in impacts to residential customers. AIU objects to such a realignment of rates at this time.

AIU acknowledges the disparity between street light fixture rates in each service territory; however, AIU says it is unclear what authority or legal basis the Commission would have to shift revenue responsibility between separate legal entities. AIU says that while the rate proceedings in this matter are consolidated, the operating utility entities that make up AIU are not. AIU argues that in future rate proceedings, the more appropriate approach to bring uniformity would likely be a rate design that moves rates toward class cost of service indicators, to the extent feasible.

b. LGI's Position

LGI claims that the street lighting fixture charge is unique in this docket because it is not a delivery service; rather it is a payment for a tangible piece of hardware and the labor involved in maintaining that hardware. LGI indicates that the delivery service charge for street lights is totally separate and apart from the street light fixture. LGI says in an over-simplified example, the fixture charge covers the cost of the arm and bulb and how many persons it takes to change the light bulb on the street light. According to LGI, because of its unique nature, there is no reason why the Commission can not separately set the rate for the street lighting fixture charge based on the cost of service as AIU did for the meter and customer charge, rather than on an across-the-board basis.

LGI states that the fixture charges vary greatly for the three electric utilities. Initially, LGI proposed that the Commission unify the fixture charges in this proceeding. LGI believes that the move to common lighting offerings across the footprint is a step toward easing customer understanding of AIU lighting offerings and streamlining operations. LGI says this standardization already occurred for Meter and Customer Charges, which are now all identical for the three utilities. LGI argues that the result of applying the across-the-board increase to street light fixtures would be to move the fixture charges further apart, making a standardized offering more difficult in the future.

LGI contends that it takes the same number of persons to change a light bulb for AmerenIP as it does for AmerenCILCO and AmerenCIPS; yet, using an across-the-board increase, the rates charged for street lighting fixtures will increase by 9.5% for AmerenCILCO, 19.2% for AmerenCIPS, and 46.0% for AmerenIP. LGI states that for AmerenCIPS the current street light fixture charge for a 100-Watt light fixture is \$3.12 per month, for AmerenCILCO the charge is \$7.13, and for AmerenIP, the charge is \$7.59. LGI says under AIU's proposed across-the-board increase, these rates would increase to \$3.72 for AmerenCIPS, \$7.81 for AmerenCILCO, and \$11.08 for AmerenIP. LGI suggests the cost of a light bulb and the cost to replace the light bulb is not nearly three times the amount for AmerenIP compared to AmerenCIPS.

LGI believes that eventually the street light fixture charge should be uniform throughout AIU's service areas; however, in its rebuttal testimony LGI focuses only on AmerenIP. Using AmerenIP's 2006 embedded COSS and the lighting specific incremental cost study performed in the last case, Ms. Hughes recommends that the increase to AmerenIP's lighting fixture rates be limited so that the fixture rates are set equal to the common incremental cost for each fixture type and size. LGI says using the incremental cost, the AmerenIP fixture charges still will be higher than the cost for AmerenCIPS and AmerenCILCO. For example, LGI indicates that the incremental cost for a 100 watt high pressure sodium vapor fixture for AmerenIP is \$8.72, while the proposed rate for the same fixture for AmerenCIPS is \$3.72 and for AmerenCILCO is \$7.81. LGI states that under its current proposal, AmerenIP customers would still pay more for fixture charges than municipalities taking service from either AmerenCIPS or AmerenCILCO but the disparity would be lower than if the fixture charges were increased using AIU's proposed across the board increase. LGI proposes that the Class B pole charge also be set equal to the incremental cost for AmerenIP. Under LGI's proposal, the revenue reduction resulting from the decrease in fixture and pole charges from the proposal by AmerenIP would be allocated to the other DS customer classes using an equal percentage increase in the DS delivery charge.

LGI claims the result of its proposal is that the street lighting fixture charge for AmerenIP customers would increase by 14.89%. LGI says the effect on other customers would increase the across-the-board increase for the DS-1 through DS-4 delivery service charge from 41.14% to 42.58%. Under LGI's proposal, the DS-5 delivery service charge rate also would increase by the same percentage (42.58%). LGI states that taking into account both the recommended fixture charge and the increase to the DS-5 delivery charge, the overall increase to the DS-5 Lighting Class is 21.37%.

LGI argues that this total lower percentage increase for the DS-5 lighting class is supported by AIU's own embedded COSS. LGI claims this study indicates that the DS-5 Lighting Class contributes a higher return on rate base at existing rates than all other DS rate classes, except for the DS-2 class. LGI asserts that applying an equal across-the-board percentage increase to all rate classes maintains or amplifies the existing disparity that DS-5 lighting rates will continue contributing higher returns relative to other rate classes.

According to LGI, AIU's opposition appears to be rooted in the fact that since it is recommending an across-the-board increase for all other classes, it believes that there should be no exception for the fixture charge. In LGI's view, AIU misses the point that the fixture charge is not a traditional delivery service charge. LGI says the delivery service charge portion of the DS-5 rate remains subject to the across-the-board increase. LGI recommends that only the light bulb, fixtures, and light bulb changing be separated from the across-the-board increase as was done with the Meter and Customer Charges that are now uniform for AmerenCILCO, AmerenCIPS, and AmerenIP.

LGI says it made three additional recommendations, all of which were accepted by AIU. LGI recommends that AIU be required to file a detailed COSS in its next rate case showing the allocation of costs between the delivery service customer classes, including a company-wide lighting cost of service analysis for AIU to identify lighting fixture costs. LGI recommends that AIU be required to file a detailed streetlight rate design study to determine cost-based lighting fixture charges. LGI recommends that any reductions to AIU's filed revenue requirement resulting from the Commission's decision should be passed along to all DS customer classes, including the DS-5 Lighting Class, in the form of a lower across-the-board percentage rate increase. LGI suggests that these recommendations should be included in the final order in this proceeding.

According to LGI, AIU attempts to confuse the issue by showing the per capita average cost per month for the fixture charge. LGI claims this is a meaningless comparison because rates are not set on a per capita basis. LGI says AIU simply takes the monthly charge for municipal lighting fixtures by municipality divided by the population of the municipality. LGI complains that AIU does not explain why this is a meaningful exercise and, if it is so meaningful, why it does not determine all of its rates on a per capita basis. LGI asserts that AIU can not hide the fact that if an across-the-board increase is granted for AmerenIP's municipal lighting fixture charge, the charge will be \$11.08 compared with only \$3.72 for AmerenCIPS and \$7.81 for Ameren CILCO.

In response to AIU's statement that LGI customers can avoid the charge by buying their own arms and bulbs if they do not like the rate, LGI claims AIU apparently wants to make the fixture charge so unreasonable that municipalities will install their own arms and bulbs rather than pay for AmerenIP's. LGI argues that while taking down AmerenIP's arms and bulbs and replacing them with municipality-owned arms and bulbs may be a long-term solution, changing out all arms and bulbs on street lights is neither an immediate nor a practical solution. Instead, LGI contends the reasonable and practical solution is for the Commission to set the municipal street lighting fixture charge based on the incremental cost.

c. Commission Conclusion

AIU proposes to increase street lighting rates, including its charges for fixtures, on an across-the-board basis. LGI objects to increasing fixture charges in AmerenIP's service area in the manner AIU proposes. LGI recommends that the Commission limit fixture charges to the incremental cost of those fixtures. AIU does not believe there is sufficient reason to deviate from its across-the-board rate increase proposal for light fixture charges. Also, AIU expresses concern about shifting revenue recovery between classes in a manner that creates impacts for residential and small business customers.

It appears to the Commission that LGI has raised a legitimate concern. In the Commission's view, ultimately, it will in all likelihood be difficult for AIU to justify light fixture charges that are as different as they currently are between AmerenCILCO, AmerenCIPS, and AmerenIP. But as previously discussed, the Commission is aware

that its rate decisions can have adverse impact on some customers if extreme care is not exercised. The Commission wishes to avoid the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if it adopts AIU's proposal to increase light fixture charges on an across-the-board basis. The Commission directs AIU, in its next electric rate case to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP.

3. Allocation of Costs to Subclasses

As discussed elsewhere in this Order, the Commercial Group opposes using an across-the-board approach to increase electric rates, favoring the use of AIU's COSS as the basis for any increase. In the event the Commission accepts the Commercial Group's recommendation on this point, the Commercial Group is concerned about the application to subclasses.

The Commercial Group argues that with respect to the DS-3 and DS-4 subclasses, the COSS do not accurately match cost to revenues on the subclass level and therefore are not reliable for differentiating subclass revenue levels. The Commercial Group states that the AmerenCILCO cost study shows the DS-4 secondary subclass as requiring a 3,729% increase. The Commercial Group claims that AIU assigned 100% of line transformer cost (\$15.1 million) for the DS-4 class to the DS-4 secondary subclass but, none of the corresponding \$2.6 million in transformation revenues that AIU received from the class. The Commercial Groups says that instead, only \$53,000 in revenue, consisting entirely of meter charge and customer charge revenue was allocated to DS-4 secondary. The Commercial Group contends that given that transformer cost but not the revenue produced from those transformers was allocated to DS-4 secondary, it is not surprising that the study would show that an enormous revenue increase would apparently be required for the DS-4 secondary. The Commercial Group concludes that AIU's COSS are generally reliable for class costs and revenues, but are not reliable at the subclass level.

While the Commission appreciates the Commercial Group's concern regarding the allocation of costs and revenue to DS-4 subclasses, as the Commission has chosen to not use AIU's COSS as the basis for setting rates in this proceeding, it does not appear that this issue need be addressed further in this Order.

4. Combining DS-3 and DS-4

a. Kroger's Position

Kroger states that the DS-3 rate class is comprised of nonresidential customers that have billing demands ranging from 150 kW up to 1,000 kW, while the DS-4 rate class is comprised of all nonresidential customers with billing demands of 1,000 kW or greater. Kroger adds that the Distribution Delivery Charge is a demand charge levied

on a per-kW basis, with rates differentiated with respect to voltage level: primary, high voltage, and transmission voltage. Kroger says unlike other charges contained within the DS-3 and DS-4 rates, the Distribution Delivery Charge is not uniform between DS-3 and DS-4. According to Kroger, for each AIU utility, and at each voltage level, the proposed Distribution Delivery Charge is significantly higher for DS-3 than DS-4. Kroger proposes that the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules should be approximately equalized. Kroger argues that there is no significant cost of service difference between DS-3 and DS-4 customers at the same voltage level, yet AIU proposes that DS-3 customers pay a substantially higher Distribution Delivery Charge.

Kroger suggests that if providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW, then perhaps these customers should not be placed into different rate classes in the first instance. Kroger also claims it is not reasonable to charge the 150 kW customer a dramatically higher per-kW Distribution Delivery Charge than the 2,000 kW customer taking service at the same voltage. In Kroger's view, the lack of a uniform Distribution Delivery Charge for DS-3 and DS-4 will result in an anomalous rate transition that will cause a great inequity. Kroger asserts for example, if there are two AmerenCILCO primary voltage customers who are otherwise identical, but one places a 1,000 kW demand on the system (DS-4) and the other places a 600 kW demand on the system (DS-3), the 600 kW customer that places a significantly smaller strain on the system will pay a higher Distribution Delivery total bill than the 1,000 kW customer. Kroger suggests that AIU's proposed Distribution Delivery Charges would send the signal to DS-4 customers to not reduce energy consumption. Kroger believes this anomaly is particularly inappropriate given the Commission's interest in promoting energy efficiency.

Kroger complains that AIU ignored the Commission's Order in the previous rate case, and failed to address the issue of whether there is sufficient justification for separate DS-3 and DS-4 classes in this proceeding. Instead, Kroger says AIU has proposed an equal percent across-the-board delivery rate increase, which retains the relative disparities between DS-3 and DS-4 established in the last proceeding, and makes the absolute differences between the rate schedules even greater. Kroger asserts that the Commission ordered AIU in its previous distribution rate case filing (Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.)) to —address [the appropriateness of maintaining separate DS-3 and DS-4 rates] in its next delivery services rate case filing.” (Order at 175)

According to Kroger, AIU's COSS in this proceeding provide even more evidence that DS-3 and DS-4 rates should be converged. Using the information from AIU's Schedule E-6 filings, Kroger prepared the table below comparing the rates of return being provided by DS-3 and DS-4 customers.

AIU COSS Rates of Return

<u>Utility Distribution Company</u>	<u>Ill. Elec.</u>	<u>Rates of Return</u>		
		<u>DS-3a</u>	<u>DS-3b</u>	<u>DS-4</u>
AmerenIP	2.75%	3.40%	5.94%	4.44%
AmerenCIPS	4.72%	9.93%	8.83%	2.77%
Ameren CILCO	6.92%	12.22%	12.89%	5.31%

Kroger says AIU is generally over-recovering costs from DS-3 customers relative to DS-4. In Kroger's view, these results are not surprising in light of the disparity in the Distribution Delivery Charges between the two customer classes. Kroger asserts that the greater the disparity in the Distribution Delivery Charges, the greater the disparity in rates of return being produced by the two customer classes.

Kroger believes the artificial distinction between DS-3 and DS-4 customers should be eliminated in this proceeding and the DS-3 and DS-4 rates should be jointly determined. Kroger calculated uniform distribution delivery charges for DS-3 and DS-4, which it presented in Kroger Ex. 1.1 using AIU's requested revenue requirement. Kroger states that the only difference between the DS-3 and DS-4 Distribution Delivery Charges is the recognition of DS-4 reactive power revenues as a credit against the DS-4 Distribution Delivery Charge. If the Commission finds merit in this argument, but is reluctant to move to uniform DS-3 and DS-4 rates at this time, Kroger suggests that, in the alternative, the Commission initiate steps in this proceeding to move the DS-3 and DS-4 rate schedules closer together over time. Kroger suggests that this could be implemented by removing 50% of the differential between the rates at this time.

b. AIU's Position

Kroger argues that the DS-3 and DS-4 rate schedules should be approximately equalized, that is, there should be no cost of service difference between customers who are served at the same voltage level. According to AIU, Kroger claims that the issue of the relationship between the DS-3 and DS-4 rates was required to be addressed by AIU in this proceeding. AIU observes that no other party has made this claim. AIU says the Commission's Order states: "When Ameren files its next delivery services rate case (assuming that filing is in 2009 or later), it should provide sufficient information for the Commission to either retain the current DS-3 classification or adopt the DS-3 classification within the subclasses proposed by Wal-Mart." (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 156) AIU claims Kroger knew or should have known upon review of the direct filing, that the DS-3 and DS-4 rate consolidation analysis had not been performed.

In AIU's view, the Commission's decision to wait until 2009 to review this issue makes sense. AIU notes that these delivery service rates first came into effect on January 2, 2007 and AIU believes waiting for some period of time is appropriate, so that any analysis offered post-2009 would have sufficient data and information. AIU alleges

that combining rates without the required analysis is a recipe for disaster. AIU contends that undue bill impacts, questionable price signals and revenue recovery concerns all remain unknown and unpredictable. AIU says the Distribution Delivery Charge recovers the remainder of the revenue requirement, and is currently set to recover the revenue requirement from DS-3 and DS-4 classes. AIU asserts that combining these rates at this time leaves too many unknowns, and is inappropriate at this time. AIU submits that further analysis of the DS-3 and DS-4 classes could lead to more rate differentiation rather than less.

c. IIEC's Position

IIEC suggests that in lieu of adopting Kroger's proposal to equalize distribution delivery service charges for DS-3 and DS-4, the Commission adopt a cost-based approach to revenue requirement allocation, which would lead to lower distribution and delivery service charges for DS-3 customers as well as DS-4 customers. IIEC generally agrees with the AIU position that DS-3 and DS-4 should not be equalized in this case, because there has not been sufficient cost analysis provided to justify the combination. Such a combination would result in lower charges for DS-3 customers and higher charge for DS-4 customers, according to IIEC. IIEC notes that Kroger's proposal is based on statements from prior delivery service rate cases that, on a conceptual basis, suggest the cost per kW of serving a customer of the same voltage level at 900 kW is not much different than the cost per kW of serving a similar customer at 1,100 kW of demand. IIEC observes that AIU witnesses point out that the cost of serving these customers may be similar, but the revenue from the customers may or may not be sufficient to recover their individual costs. According to IIEC, this suggests that rate changes not discussed in this record may be needed to implement the Kroger approach. IIEC also argues that the Commission directed that this issue be considered in a rate case filing in 2009 or later citing to Docket Nos. 06-0070, 07-0071, and 06-0072 (Cons.) (Order at 156).

IIEC argues further that Kroger's alternative proposal to equalize delivery distribution charges for DS-3 and DS-4 by removing 50% of any difference between the rates as they exist today does not mitigate AIU's concerns in terms of potential impacts and consequences of equalizing these rates at this time. Adoption of the AIU proposal would not, according to IIEC, reduce by 50% the magnitude of the problems associated with the Kroger proposal. IIEC adds that the impacts of moving towards equalization remain unknown and unpredictable based on the record in this case. IIEC, therefore, recommends that the proposal to combine DS-3 and DS-4 be rejected in this case.

d. Commission Conclusion

In AIU's last rate case, the Commission entertained not only arguments over the possibility of combining rates DS-3 and DS-4, but also the possibility of splitting rate DS-3 into subclasses. The Order in AIU's last rate case clearly contemplated reconsidering whether to split rate DS-3 into subclasses in 2009 or after. While the Order was not quite as clear with respect to when it would reconsider combining rates DS-3 and DS-4,

the Commission does not believe combining rates DS-3 and DS-4 in this rate case and, possibly creating a new rate DS-3 in a subsequent rate case constitutes sound ratemaking policy. In fact, it seems to contradict the rate design principle commonly called rate continuity. Thus, while the Commission remains open to the possibility of restructuring rates DS-3 and DS-4 when sufficient information is available to fully analyze the implications of any restructuring, the Commission affirms its decision from Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and directs AIU to address these two issues in its first electric rate cases filed in 2009 or thereafter.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

- (1) AmerenCILCO, AmerenCIPS, and AmerenIP are Illinois corporations engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and are public utilities as defined in Section 3-105 of the Act;
- (2) the Commission has jurisdiction over the parties hereto and the subject matter herein;
- (3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendix A attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's electric operations; Appendix B attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' electric operations; Appendix C attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's electric operations; Appendix D attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's gas operations; Appendix E attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' gas operations; and Appendix F attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's gas operations;
- (4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2006, as adjusted; such test year is appropriate for purposes of this proceeding;
- (5) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's electric delivery service operations for the test year ending December 31, 2006, as adjusted, is \$240,625,000;

- (6) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' electric delivery service operations for the test year ending December 31, 2006, as adjusted, is \$443,743,000;
- (7) for purposes of this proceeding, the net original cost rate base for AmerenIP's electric delivery service operations for the test year ending December 31, 2006, as adjusted, is \$1,254,459,000;
- (8) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is \$183,734,000;
- (9) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' gas delivery service operations for the test year ending December 31, 2006, as adjusted, is \$181,735,000;
- (10) for purposes of this proceeding, the net original cost rate base for AmerenIP's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is \$518,857,000;
- (11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.01%; this rate of return incorporates a return on common equity of 10.65%;
- (12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.20%; this rate of return incorporates a return on common equity of 10.65%;
- (13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.68%; this rate of return incorporates a return on common equity of 10.65%;
- (14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 8.03%; this rate of return incorporates a return on common equity of 10.68%;
- (15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 8.22%; this rate of return incorporates a return on common equity of 10.68%;
- (16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.70%; this rate of return incorporates a return on common equity of 10.68%;
- (17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of \$115,827,000 and net

annual operating income of \$19,273,000 based on the test year approved herein;

- (18) the rate of return for AmerenCIPS set forth in Finding (12) results in base rate electric delivery service operating revenues of \$218,466,000 and net annual operating income of \$36,387,000 based on the test year approved herein;
- (19) the rate of return for AmerenIP set forth in Finding (13) results in base rate electric delivery service operating revenues of \$442,556,000 and net annual operating income of \$108,887,000 based on the test year approved herein;
- (20) the rate of return for AmerenCILCO set forth in Finding (14) results in base rate gas delivery service operating revenues of \$71,308,000 and net annual operating income of \$14,754,000 based on the test year approved herein;
- (21) the rate of return for AmerenCIPS set forth in Finding (15) results in base rate gas delivery service operating revenues of \$70,450,000 and net annual operating income of \$14,938,000 based on the test year approved herein;
- (22) the rate of return for AmerenIP set forth in Finding (16) results in base rate gas delivery service operating revenues of \$167,424,000 and net annual operating income of \$45,140,000 based on the test year approved herein;
- (23) the electric delivery service rates as well as the gas delivery service rates of AmerenCIPS and AmerenIP which are presently in effect are insufficient to generate the operating income necessary to permit each company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;
- (24) the electric and gas delivery service rates of AmerenCILCO which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base: these rates should be permanently canceled and annulled;
- (25) the specific rates proposed by AmerenCILCO, AmerenCIPS, and AmerenIP in its respective initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates of each company should be permanently canceled and annulled consistent with the findings herein;

- (26) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of \$115,827,000, which represents a decrease of \$2,778,000 or (2.25%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;
- (27) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of \$218,466,000, which represents an increase of \$21,956,000 or 10.31%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (12) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;
- (28) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of \$442,556,000, which represents an increase of \$103,867,000 or 29.16%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (13) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;
- (29) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of \$71,308,000, which represents a decrease of \$9,234,000 or (11.19%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (14) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;
- (30) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of \$70,450,000, which represents an increase of \$7,659,000 or 11.74%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (15) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;
- (31) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of \$167,424,000, which represents an increase of \$39,792,000 or 30.01%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding

(16) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

- (32) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AmerenCILCO, AmerenCIPS, and AmerenIP should incorporate the rates and rate design set forth and referred to herein;
- (33) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than three days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period; and
- (34) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for electric delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in electric delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in

accordance with Findings (26), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (27), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (28), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (29), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (30), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (31), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 24th day of September, 2008.

(SIGNED) CHARLES E. BOX

Chairman

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

- CASE 08-E-0539 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.
- CASE 08-M-0618 - Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers.

ORDER SETTING ELECTRIC RATES

(Issued and Effective April 24, 2009)

TABLE OF CONTENTS

I. INTRODUCTION.....	1
A. Procedural History	2
B. Summary of Public Comments	9
II. SALES REVENUES.....	10
A. Sales Revenue Forecast	10
B. Billing and Payment Processing / Merchant Function Charge / Metering Revenues	13
III. OTHER OPERATING REVENUE.....	14
A. Purchase of Receivables Discount and Other Update Issues	14
IV. EXPENSES - COMPANY LABOR O&M.....	17
A. Staffing Requests	17
1. Historic Hiring Practices Adjustment.....	17
2. DPS Staff's Department-Specific Adjustments.....	22
a. Electric (Distribution) Operations--Various	22
b. Electric (Distribution) Operations--Enhanced Project Planning.....	24
c. Shared Services--Programmers	25
d. Other Normalizations	26
e. State Regulatory Affairs	27
f. Emergency Management	28
g. Gold Program	30
B. Productivity Adjustments	33
1. Positions of the Parties.....	34
2. Discussion.....	36
C. Labor Escalation	38
1. Wage Progression Increases.....	38
2. End of Test Year Employment Count.....	41
D. Normalization (Vacancy) Adjustment	42
E. Variable Pay	46
1. Positions of the Parties.....	47
2. Discussion.....	51
F. Other Incentive Compensation (Non-Officer and Officer Long-Term Compensation)	55
G. Directors' Compensation	56
V. EXPENSES - OTHER O&M.....	57
A. Pensions/OPEBs Expense Level	57
B. Municipal Infrastructure Support Expense Level	58
1. Positions of the Parties.....	60
2. Discussion.....	63
C. T&D Non-Labor Program Expense	64
1. Five-Year Underground Inspection Program.....	64
a. Positions of the Parties	65
b. Discussion	66
2. Structural Integrity/Station Betterment.....	69
3. Mobile Stray Voltage Testing.....	70
4. Annual Stray Voltage Testing.....	71

5. Maintenance Associated with Capital Work.....	72
D. Shared Services Non-Labor Program Expenses	73
1. West 28 th Street	73
2. Central Field Services - Vehicle Fuel.....	75
E. Informational & Institutional Advertising	77
1. Positions of the Parties.....	78
2. Discussion.....	80
F. Employee Welfare Programs	82
G. Insurance	84
1. Directors and Officers Liability Insurance.....	84
a. Positions of the Parties.....	85
b. Discussion.....	88
2. Other Insurance Escalation Rate.....	91
H. Research & Development Capitalization Adjustment	94
I. Regulatory Commission Expense	97
J. Energy Efficiency Related Programs	99
K. Correction for System Benefit Charge Expenses	101
VI. TAXES OTHER THAN INCOME TAXES.....	101
A. Property Tax Expense Level	101
B. Reconciliation of Property Taxes	105
C. 2008 Property Tax Deferral	107
D. Minimizing Future Property Taxes	109
VII. DEPRECIATION - PAYGO.....	110
A. Background	110
B. The Arguments	112
C. Discussion	115
VIII. COST OF CAPITAL.....	116
A. The Cost of Common Equity and the Sharing Trigger and Cap	116
1. Background.....	116
2. The Role of Precedent in General.....	119
3. DCF Model Issues.....	121
4. The Capital Asset Pricing Model.....	127
5. Westchester's Exception.....	129
6. Exceptions Concerning Weight.....	130
7. Credit Quality Adjustment.....	134
8. The Company's Revised Request for 10.6%.....	137
9. ROE Conclusion.....	140
10. Earnings Sharing Trigger and Cap.....	141
B. Cost of Debt	144
C. Overall Rate of Return	145
IX. RATE BASE.....	145
A. Lower Allowance for Infrastructure	145
1. Transmission and Distribution.....	145
a. Introduction.....	145
b. DPS Staff's Historic Spending Adjustment.....	148
c. DPS Staff's Project- or Program-Specific Adjustments	151

d. Corrections and Updates	154
2. General Equipment.....	157
3. Electric Production.....	165
4. Facilities – West 125th Street Property.....	167
B. Capital Expenditure Cap/Reconciliation and Capital Expenditure Reporting/Rate Case Demonstration	170
1. Introduction.....	170
2. Expansion of the One-Way Reconciliation.....	171
3. Advanced Technology and Storm Hardening and Response True-Up Proposals.....	174
4. The Cost of Removal.....	176
5. Proposed Reporting Requirements.....	177
6. Proposed Rate Case Filing Requirements.....	178
C. EB Cap Adjustment	181
D. Working Capital – Lead-Lag Study	183
E. Rate Base Treatment for Deferred Overhaul and Local Law 11 Expenditures	186
X. REVENUE ALLOCATION/RATE DESIGN.....	188
A. 2005 ECOS, Revenue Allocation, and Tolerance Bands	188
1. 2005 Embedded Cost of Service Study	189
2. Revenue Allocation	198
3. Tolerance Bands	201
4. Discussion	204
B. TCC Treatment vis-à-vis NYPA.....	206
1. Background	206
2. The Arguments	209
3. Discussion	218
4. Revenue Allocation Treatment Resulting From A Change in Imputed TCC Revenues	223
C. SC 1 Customer Charge.....	224
D. BIR Proposal.....	226
E. Shore Power Tariff.....	229
F. Submetering.....	233
1. SC 8 and SC 12 Customers	233
2. Dormitory Submetering	239
G. Geography-Based Delivery Rates	243
H. Electronic Tariff.....	246
I. Unbundling Delivery Rates	249
J. Make-Whole	250
K. PSL §18-a(6) Assessment	250
XI. OTHER ISSUES.....	253
A. Performance Metrics	253
1. Reliability Performance Mechanism	253
a. Introduction.....	253
b. RPMs in General.....	253
c. Frequency and Duration of Outages.....	257
(i) The Arguments.....	257
(ii) Discussion.....	265
d. Major Outage Mechanism for Networks.....	268

e.	Service Restoration Metric.....	270
f.	Remote Monitoring System Metric.....	272
g.	Program Standards.....	275
h.	Effective Period of the Reliability Performance Mechanism.....	277
2.	Customer Service Performance Mechanism	279
B.	Three-Year Rate Plan.....	281
C.	Deferral Accounting/Reconciliations	283
1.	New Laws and New Taxes	283
2.	Offsets of Deferred Debits and Credits	285
D.	Mandatory Hourly Pricing (MHP).....	285
1.	MHP Billing	286
E.	Retail Access Issues.....	288
1.	Outreach and Education	288
2.	Display of Full Service Supply Costs on Retail Access Bills	291
3.	Unaccounted for Energy	295
4.	Timely Meter Reading Information	297
F.	Estimated Billing/Use of Automated Meter Reading (AMR) ..	299
1.	Use of Load Shapes and Rectifying Data Aberrations ...	299
2.	Strategic Installation of AMR	301
G.	Contributions in Aid of Construction.....	306
1.	DPS Staff's Proposals	306
2.	The Company's Proposal	308
3.	Discussion	308
H.	Changes to Encourage CHP/DG/Solar	309
I.	Outreach & Education Reporting.....	320
J.	Process for Aggregating / Using Building Usage Data: Access to Information for Building Owners.....	321
K.	Clean Air Act and Regional Greenhouse Gas Initiative (RGGI) Costs.....	324
L.	Business Incentive Rate Lost Revenue.....	326
M.	Compliance with Public Service Law §66(19).....	327
N.	DOJ Investigation.....	328
XII.	CUSTOMERS' ABILITY TO PAY.....	331
A.	Introduction.....	331
B.	Economic Impacts in General.....	332
C.	The Options.....	335
1.	A Macro Adjustment to the Company's T&D Investment and Expenses and the Austerity Budget Proposal	335
2.	NYPA's Cost-Effectiveness Proposal	341
D.	Discussion.....	341
XIII.	CONCLUSION.....	344
	ORDER.....	345
	DISSENT	
	APPENDICES	

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on April 21, 2009

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris, dissenting
Robert E. Curry, Jr.
James L. Larocca

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the Rates, Charges, Rules and Regulations of
Consolidated Edison Company of New York, Inc.
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Service Law, Section 113(2), of a Proposed
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ORDER SETTING ELECTRIC RATES

(Issued and Effective April 21, 2009)

BY THE COMMISSION:

I. INTRODUCTION

These cases primarily concern the terms and conditions of electric delivery service for the full service and retail access customers of Consolidated Edison Company of New York, Inc. Following the cases' procedural history and a summary of the public comments, this order discusses all issues raised in exceptions to the January 7, 2009 Recommended Decision, in proposed revenue requirement updates, and in the parties' trial briefs concerning non-revenue requirement issues. Issue-specific discussions are followed by a final conclusion section and ordering paragraphs. For the reasons discussed below, we

are allowing an annual electric delivery service revenue increase of \$721.405 million (19.7% on total system delivery revenues and 6.1% on a total system electric revenue basis).

A. Procedural History

On May 9, 2008, Consolidated Edison Company of New York, Inc. (Consolidated Edison or the Company) filed amendments to its electric tariff schedules by which it proposed to change its rates, charges, rules, and regulations. The Company estimated that the tariff revisions, if approved, would produce an annual increase in electric revenues of \$654.1 million over what they otherwise would be in the 12 months ending March 31, 2010 (the Rate Year). The Company stated that the \$654.1 million figure is \$427.7 million lower than it would otherwise be because of Company proposals to extend the recovery periods for certain expenses, defer the recovery of a depreciation reserve deficiency, and seek at that time a return on common equity of 10.0% as opposed to the 11.0% figure supported in the direct testimony of the Company's witnesses (collectively, the Amelioration Proposals).

The May 9, 2008 filing also provided information in support of further electric revenue increases of \$475 million and \$421 million, respectively, for the 12 months ending March 31, 2011 (Rate Year Two) and March 31, 2012 (Rate Year Three). These two amounts are lower than they otherwise would be because of the Amelioration Proposals. As an alternative, the Company proposed three levelized annual electric revenue increases of \$556.7 million each.

The filed tariff revisions were suspended through April 5, 2009.¹

¹ Case 08-E-0539, Order Suspending Major Rate Filing (issued May 29, 2008) and Untitled Order (issued September 17, 2008). An extension of the suspension date is discussed below.

In a letter dated May 23, 2008, the Company reported on and proposed the disposition of a property tax refund from the Town of Mount Pleasant in the amount of \$434,000. That matter was docketed in Case 08-M-0618 and assigned for consideration under Public Service Law (PSL) §113(2) in connection with the pending electric rate filing.

Discovery ensued and active parties were identified. The Company advised that it responded to approximately 1,600 discovery requests, most of which had multiple parts. A formal litigation schedule was adopted without objection.² Among other things, it called for the Company to offer an informal update on July 25, 2008, for DPS Staff and intervenors to file their direct cases on September 8, 2008, and for the submittal of rebuttal and formal update presentations on September 29, 2008.

On June 18, 2008, the Company hosted a technical conference to provide interested parties with an overview of its May 9, 2008 filing.³

Notices of the pending electric tariff filing and tax refund petition, inviting public comments on both, were published in the State Register on September 24 and October 1, 2008, respectively. A notice inviting public comments through January 25, 2009 was also published prominently in November 2008 in the New York Post, the Staten Island Advance, and the Journal News. The published notices provided information about the cases, including the major factors driving the requested increase, and invited comments via U.S. mail, the internet, and the Department's toll-free opinion line through January 25, 2009. Affidavits of publication were received on November 26, 2008.

² Case 08-E-0539, Ruling on Schedule (issued June 24, 2008).

³ The handout for the conference is Exhibit (Ex.) 209.

Evidentiary hearings commenced on October 15, 2008 and concluded on October 24, 2008. Commissioner Robert E. Curry, Jr. participated in the October 23, 2008 hearing. As of the time of the hearings, the Company's updated and corrected electric revenue increase request for the Rate Year was \$819.024 million.⁴ That figure remained \$427.7 million lower than it otherwise would be because of the Amelioration Proposals. The Company's revenue requests for the second and third rate years were not updated or corrected as of that date, nor was the alternative proposal for three levelized revenue increases. Meanwhile, Department of Public Service (DPS) Staff's corrected and partly updated direct case around that time supported an annual electric revenue increase of \$346.117 million in the Rate Year.⁵ Neither DPS Staff nor any intervenor provided alternative estimates of any revenue increases required beyond the Rate Year.

The evidentiary record includes approximately 5000 pages of transcript, a few of which are protected from public disclosure on an interim basis.⁶ There are also 460 exhibits.⁷ Some of the exhibits are protected on an interim basis from public disclosure in whole or in part.

Initial trial briefs were filed and served by the Company; DPS Staff; the Consumer Protection Board (CPB); the New

⁴ Ex. 403. Corrections reported subsequent to the Recommended Decision (R.D.) are discussed below.

⁵ Ex. 420.

⁶ 5023 transcript (Tr.) pages less Tr. 406, line 22 through Tr. 428, line 7. The latter are not in evidence, but remain in the transcript as an offer of proof. See Cases 08-E-0539 and 08-M-0618, Ruling on Motion to Strike (issued November 4, 2008).

⁷ Numbers 1-462 with the exceptions of 72, 309, 334, all of which are blank, and counting exhibits 448-A and 448-B separately. One further exhibit, submitted after the recommended decision was issued, is discussed separately below.

York Power Authority (NYPA); the City of New York, the Metropolitan Transportation Authority, and the Port Authority of New York and New Jersey (jointly, the NYC Government Customers); Westchester County (Westchester or the County); Consumer Power Advocates (CPA);⁸ the New York Energy Consumers Council (NYECC);⁹ the Pace Energy and Climate Center (Pace); the Retail Energy Supply Association (RESA); the Small Customer Marketer Coalition (SCMC); and Joint Supporters.

On December 3, 2008, a notice of impending negotiations was filed and served by the Company. We received a memorandum reporting on that filing dated December 4, 2008. Negotiations did not culminate in a joint proposal. However, the initial trial briefs of the Company and DPS Staff both discuss issues on which there is agreement between these two parties or among them and other parties.¹⁰ Those issues concern, among others, unbilled revenues, rents from transmission towers, late payment charges, the recovery of deferred targeted Demand Side Management (DSM) costs, Transmission Service Charges, the exclusion of SC 13 from the Revenue Decoupling Mechanism (RDM), a Transmission Congestion Contract (TCC) revenue imputation of \$120 million, the disposition of various property tax refunds, and a number of other issues.

⁸ CPA comprises large, high load factor SC 9, time-of-day, not-for-profit organizations including Fordham, Mount Sinai Medical Center, Memorial Sloan Kettering, Beth Israel Medical Center, St. Luke's-Roosevelt Hospital Center, Long Island College Hospital, New York Eye and Ear Infirmary, Montefiore Medical Center, NYU Medical Center, and New York University.

⁹ NYECC members include a broad spectrum of energy buyers, including hospitals, universities, financial institutions, residential and commercial property managers, public benefit corporations, energy service companies, and energy consultants.

¹⁰ The Company's Initial Brief, pp. 527-534 and DPS Staff's Initial Brief, pp. 343-360. DPS Staff's discussion is more extensive.

On December 8, 2008, reply trial briefs were filed and served by the Company, DPS Staff, CPB, NYPA, the NYC Government Customers, Westchester County, CPA, NYECC, Pace, RESA and Joint Supporters. The initial and reply trial briefs totaled approximately 1,580 pages.

Twenty-six calendar days after the initial trial briefs were filed, it was readily apparent to the judges that they would not be able to analyze and prepare recommendations on all disputed issues by the targeted recommended decision issuance date of January 5, 2009. (The latter date was three months prior to the then-effective suspension date of April 5, 2009). Accordingly, in an electronic message dated December 17, 2008, the judges advised all parties of their intention to complete a recommended decision on all revenue requirement issues (Phase I issues) on or shortly after January 5, 2009 and to prepare a separate recommended decision on all other (Phase II) issues. They anticipated a second decision by us on Phase II issues after April 5, 2009.

In an electronic message dated December 18, 2008, the judges invited the Company, DPS Staff, and CPB to provide factual updates to inputs to their respective cost of common equity analyses. The judges relied on some of the factual information in their recommendations. The judges did not rely on any information provided by the Company that went beyond the information they had requested.

In late December 2008, the Company filed some further updates, including one for a 7.5% New York City property tax rate increase effective January 1, 2009. This is greater than the 7% increase the Company had been forecasting.

In the recommended decision issued January 7, 2009, the judges concluded that the Company needs \$632.5 million of additional annual revenues to meet the minimal, reasonable cost of providing electric delivery service in the Rate Year. Major

drivers underlying the \$632.5 million (and contemporaneous estimates of the associated dollars) include higher property tax expense (\$276 million), higher rate base and associated depreciation expense (\$258 million), a higher cost of capital, including 10.0% on common equity (\$104 million), increased expense for pensions and other post-employment benefits (OPEBs) (\$67 million), and decreased TCC revenues to offset delivery service revenue requirement (\$30 million).¹¹

The recommended decision summarized competing proposals to reduce the Company's Rate Year expenses and the amount of incremental revenues required on the grounds that the economic downturn reduces the Company's customers' collective ability to pay higher electric rates. However, the judges made no substantive recommendation on the propriety of such proposals.

On or before January 27, 2009, briefs on exceptions were filed by the Company, DPS Staff, CPB, NYPA, the NYC Government Customers, Westchester County, CPA, and RESA. Subject to other possible updates, the Company and DPS Staff were supporting electric revenue increases as of that date of \$935.14 million and \$484.1 million, respectively, a difference of \$.45 billion.

In a letter from the Office of Consumer Services dated January 27, 2009, further public comment was solicited from 400 community and political leaders through February 11, 2009. The letter was accompanied by a fact sheet and stated that comments could be offered by writing, posting comments electronically on the Department's website, or calling the Department's toll-free opinion line.

For a variety of reasons, including concern about customer confusion if we were to adopt an interim across-the-

¹¹ There are other increases, as well as offsets, that net out to \$632.5 million.

board (or equal percentage) revenue allocation and rate design in March 2009, and a different, final revenue allocation and rate design several months thereafter, members of Advisory Staff contacted the Company in late January 2009 about the possibility of the Company extending the statutory suspension date.¹²

In response, the Company offered to extend the suspension date from April 5, 2009, through April 30, 2009, subject to the condition that it be made whole for any revenue shortfall during that 25-day period.¹³

Once it was apparent the Company would extend the suspension date, the judges were instructed to prepare a report on all Phase II issues so that a decision on all contested Phase I and II issues could be rendered prior to the extended suspension date. This instruction was given, notwithstanding the judges' prior expectations about a second recommended decision, because there was not adequate time for the judges to prepare a recommended decision on Phase II issues, for a second recommended decision to be issued for exceptions, for any exceptions to be filed, analyzed, and reported to us along with the Phase I exceptions and updates, and for all issues to be decided finally in April 2009.

On or before February 11, 2009, briefs opposing exceptions on Phase I issues were filed by the Company, DPS Staff, CPB, NYPA, the NYC Government Customers, Westchester County, NYECC, and RESA.

On February 13, 2009, the judges submitted their 126-page report on Phase II issues. On February 17, 2009, an order

¹² There was also interest in our being able to consider simultaneously all rate of return issues and the dollar amounts to be at risk under the Company's reliability and service quality performance mechanisms. Revenues to match the low-income customer discount are also impacted by our revenue allocation and rate design determinations.

¹³ February 2, 2009 letter from Mr. Lubling to Secretary Brilling.

was issued extending the suspension date subject to a make-whole through April 30, 2009.¹⁴ That order reserved judgment on the issue of exactly how the make-whole would be implemented. That issue is addressed in Section X (J) and an ordering paragraph.

It was apparent to the judges that some parties' post-recommended decision arguments refer to one or more attachments to Exhibit 396 that were not introduced into evidence. The attachments and a supporting affidavit were subsequently submitted. The original Exhibit 396 is now Exhibit 396-A and the supplemental attachments and the sworn affidavit comprise Exhibit 396-B.

The Company filed two different sets of updates after all the post-recommended decision briefs were submitted. As of these updates, the Company was requesting incremental electric revenues for the Rate Year of \$851 million as of March 25, 2009 and \$1.003 billion as of April 6, 2009. The major difference between the two is the increased assessment under Public Service Law §18-a.

B. Summary of Public Comments

Ninety-five public comments were received in these cases in the period between June 9, 2008 and March 25, 2009. The vast majority were received via the Internet.¹⁵ Among others, comments were submitted (in chronological order) by State Assemblymember Sandra R. Galef from Ossining, State Senator Jeffrey D. Klein of the Bronx, the Lefrak City Merchants' Association of Queens, the United States Environmental Protection Agency, and New York City Council Member Tony Avella of Bayside Queens.

¹⁴ Case 08-E-0539, Untitled Order (issued February 17, 2009).

¹⁵ Of these, 79 were received by the original January 25, 2009 due date, another 9 were submitted by the February 11, 2009 extended due date, and the balance were submitted after the deadline.

All public comments are summarized in table form in Appendix V. The comments of EPA are also discussed in the body of our order. Key themes expressed by members of the public are that rates are too high, and that further increases are untenable in light of the poor economy and anticipated impacts on the elderly, others on fixed incomes, and the poor. Many feel that they are being forced to absorb ever-increasing costs without any increase in income and therefore the Company should be required to do the same in the face of tax and other cost increases. There are also calls for belt-tightening by the Company.

Significant frustration is expressed by some customers about why the Company is asking that rates go up while commodity costs have dropped. Others express concern that rates are increased as usage goes down on account of increased conservation.

As discussed in the sections that follow, the increased revenues we allow today reflect significant increases in several specific expense areas over what is reflected in the Company's current rates. The austerity adjustment we adopt also reflects our expectation, in light of the extraordinary hard times being experienced by the Company's customers, that the Company can and should do more to cut some of its other costs without negatively impacting electric service reliability, safety, or quality in the near- or long-term.

II. SALES REVENUES

A. Sales Revenue Forecast

The recommended decision endorsed the Company's revised sales forecast, along with DPS Staff's 239 GWH demand side management (DSM) adjustment. The Company acquiesces to the DPS Staff DSM adjustment, but states that the recommended decision overlooked the Company's inclusion of all but 34 GWH of

that adjustment in its updated sales forecast.¹⁶ The Company says our decision accordingly should reflect a corrected sales figure, reducing the forecast in the recommended decision by the difference of 205 GWH; and a concomitant downward adjustment of only \$1.9 million--rather than the recommended decision's \$14.7 million--in the revenue to be collected from rates in the Rate Year. Our review indicates that the Company is correct and we adopt the corrected adjustment.

In addition to its DSM adjustment, DPS Staff maintained that four elements of the Company's sales forecasting methodology should be changed: employment update, personal income variable, Service Classification (SC) 2 (General-Small) employment variable, and cooling degree-days. Its forecasting witness did not propose any adjustment based upon those four methodological differences, however, because his estimate differed by only 43 GWH, in the aggregate, from the Company's original filing. DPS Staff contends that the recommended decision erred in accepting the Company's revised sales forecast, which reflected only the employment update of the four changes DPS Staff proposed to the Company's forecast methodology.¹⁷ On exceptions, DPS Staff states that some of its proposed corrections to the four variables drove the forecast upward, some downward, and only their aggregate effect was minimal and led DPS Staff to conclude that the Company's original forecast was acceptable. DPS Staff urges us to reject the recommended decision's sales forecast, which includes only the employment update correction. Instead, DPS Staff maintains that we should adopt the Company's originally filed forecast,

¹⁶ The Company's Brief on Exceptions (BoE), p. 6. Parties' briefs on exceptions will be cited as "BoE." Briefs opposing exceptions will be referred to as "BOE." Initial trial briefs will be cited as "Initial Brief" and reply trial briefs as "Reply Brief."

¹⁷ DPS Staff's BoE, p. 5.

modified only by DPS Staff's DSM adjustment. In its brief opposing exceptions, DPS Staff reverses position and says that all four of its sales forecasts adjustments should be adopted in their entirety.¹⁸

In opposition to DPS Staff's arguments, the Company claims that DPS Staff failed to establish on the record that its four adjustments are interrelated; and the Company updated all variables, not just the employment forecast. It contends that DPS Staff's proposal to use the Company's original, now stale, forecast would rely on outdated projections (such as positive employment growth) that are unrealistically optimistic in light of the severe economic downturn that took place since the Company's original filing. The Company adds that DPS Staff never quantified the impact of its three methodological adjustments that were not recommended, and did not respond to the recommended decision's request that the parties indicate the extent to which they agreed or disagreed with the judges' understanding of the arguments on those adjustments.¹⁹

DPS Staff's brief on exceptions does not ask that the forecast be updated using its revisions to all four variables. Rather, it proposes that the Company's original forecast be used, modified only by DPS Staff's DSM adjustment. Nor did DPS Staff's brief on exceptions propose, contrary to the recommended decision, that we decide the disputed issues about the personal income variable, the SC 2 employment variable, or the cooling degree-days variable. Only in its brief opposing exceptions does DPS Staff seek to have the forecast updated using the four revised variables. Holding off until its brief opposing exceptions deprives other parties of the opportunity to respond to that position. Therefore, we will not consider the request

¹⁸ DPS Staff's BOE, p. 2.

¹⁹ The Company's BOE, pp. 1-3.

in its brief opposing exceptions to adopt adjustments for all four variables.

The record itself does not directly address whether any of the four disputed variables individually has a significant effect on the sales forecast. It includes only DPS Staff's testimony that in the aggregate the difference between the Company's original filing forecast and the DPS Staff forecast is in the range of acceptable forecasting error; and that the Company's estimate as originally filed should be accepted. There is no record evidence either in support or contradiction of DPS Staff's allegation on exception that only in the aggregate is the difference between the Company's original filing forecast and the DPS Staff forecast insignificant. Nor, given the state of the record, do we find adequate support for DPS Staff's proposal that we adopt the Company's originally filed forecast, modified only by its DSM adjustment. In any event, the revenue decoupling mechanism (RDM) now in place for the Company will protect both ratepayers and the Company, in the event that the sales revenue forecast proves to be understated or overstated. Consequently, we will adopt the recommendation of the judges.

B. Billing and Payment Processing / Merchant Function Charge / Metering Revenues

The Company and DPS Staff agree on the method to be used to determine Rate Year charges for the Company's competitive services -- merchant function charge, competitive metering charges, and billing and payment processing charges. Since different sales forecasts affect the level at which those competitive service charges should be set, both parties also agree that the charges should be adjusted once the sales issue is resolved. The recommended decision asked that the parties specify in briefs on exceptions what the revised charges should be, based on the judges' sales forecast recommendations.

In response to the judges' request, the Company provides calculations that it indicates should be considered preliminary, pending our decisions on the sales forecast and rate increase. DPS Staff essentially agrees, noting the competitive services charges should be recalculated based upon our sales forecast, revenue requirement, and rate design determinations. The competitive service charges should be reset consistent with the terms of this order.

III. OTHER OPERATING REVENUE

A. Purchase of Receivables Discount and Other Update Issues

The Company forecast Rate Year revenues from its Purchase of Receivables (POR) program of \$6.880 million and DPS Staff argued that the latest available information through August 2008 supported a Rate Year forecast of \$7.710 million. The judges recommended DPS Staff's forecast. Noting that the Policy Statement on Test Periods in Major Rate Proceedings generally invites updated forecasts only through the time of the hearings at which DPS Staff's direct testimony and exhibits were cross-examined, the judges recommended that an updated forecast for this item be considered only if such updates would be considered for other items as well.²⁰

The Company does not object to the recommendation in support of DPS Staff's forecast. However, it proposes that the forecast for this item not be further updated for the following reasons:²¹

- a. Updated forecasts are not usually considered this late in a rate case.
- b. Updating the forecast for this item would open up the door to numerous other updated forecasts.

²⁰ R.D., pp. 32-33.

²¹ The Company's BoE, pp. 7-8.

Addressing the issue of updates more broadly, the Company adds the following:²²

- c. The Company agrees with other recommended updates of material and volatile cost elements such as property taxes, interest expense, pensions and other post-employment benefits (OPEBs) expense, return on equity, letter of credit costs, and vehicle fuel.
- d. The Company opposes any further update of its forecast capital expenditures, especially given that it takes no exception to the recommended one-way, downward-only reconciliation of any differences between projected and actual T&D capital investment.
- e. The Company states that it takes no position on the judges' recommendation to reflect the City's January 2009 construction plan forecast for purposes of estimating Municipal Infrastructure support expense levels.
- f. The Governor's budget proposes to increase the Company's electric department assessment under PSL §18-a by approximately \$112.5 million per year and any actual increase in its assessment should be reflected in rates or deferred for future recovery from ratepayers.

DPS Staff opposes the Company's arguments as follows:²³

- a. In addition to updates with which the Company agrees, known changes to operating revenues or costs should be reflected such as for:
 - i. Transmission Service Charge (TSC) revenues;
 - ii. Municipal Infrastructure Support expenses;
 - iii. Labor capitalization rate;
 - iv. Capital expenditures;
 - v. Federal and state tax law changes; and
 - vi. PSL §18-a assessment changes if known at the time of our decision.
- b. As to TSC revenues specifically, DPS Staff previously proposed the pass back of this deferral

²² Id., pp. 8-9.

²³ DPS Staff's BOE, pp. 3-7.

be updated (Tr. 2648) and the latest information available suggests the Company's revenue requirement should be reduced by \$4 to \$5 million for this known change.²⁴

- c. Based on the latest New York City Commitment Plan, the Company's forecast for Municipal Infrastructure Support expense should be lowered by \$4 million.
- d. The Company recently disclosed a 2009 labor capitalization rate of 38.0%, up from 35.5% in 2008. The impact of this known change should be reflected.²⁵
- e. Congress is considering tax law changes, related to the economic stimulus package, that may reduce the Company's revenue requirement by \$20 to \$30 million per year. These "known changes" should be reflected in revenue requirement in accordance with the Statement of Policy on Test Periods in Major Rate Proceedings.
- f. In the event PSL §18-a is amended after a decision is rendered in these cases, the issue will likely be addressed on a generic basis and the Company should not be given preferential treatment (apparently referring to the Company's request for approval now to defer such costs later) merely because it has a pending rate filing.
- g. The Company reported on December 31, 2008 additional property tax refunds of \$4.9 million, but a requisite hearing has not been held and, thus, action cannot yet be taken on these.

Our revenue requirement determination reflects post-recommended decision known changes in costs for property taxes, pensions and OPEBS, the Company's labor capitalization rate change (from 35.5% to 38.0%), an increase on the pass back of Transmission Service Charge Revenues, the Company's most recent 12-month uncollectibles write-off rate, the effects of accelerated depreciation under the American Recovery and Reinvestment Act, increases in the PSL §18-a assessment (to be

²⁴ The latest data on which it relies are not identified.

²⁵ DPS Staff also discusses proposed updates for actual and forecast reductions in plant in service. These all are discussed in Section IX-Rate Base.

recovered via surcharge), and changes in the cost of debt. While some of these known changes were provided after the due date for parties' briefs on exceptions, they are reflected in large part either because the changes result from government action or because they are otherwise largely beyond the Company's control. Given that some of the updates put significant upward pressure on revenue requirement, it is also fair to reflect updates having the opposite effect.

As discussed in some of the sections that follow, we are also relying on some actual 2008 expenditure levels as a check on the competing forecasts for the Rate Year. Operation and maintenance expenses in this category include five-year underground inspection costs and municipal infrastructure support expenses.

IV. EXPENSES - COMPANY LABOR O&M

A. Staffing Requests

1. Historic Hiring Practices Adjustment

The Company's rate request included full funding for all requested new positions for the entire Rate Year. The judges recommended a slightly revised version of a DPS Staff proposal to calculate the cost of payroll, benefits, and related expenses for new employees taking into account the lag in the Company's filling of new positions over the course of the Rate Year, based on its demonstrated performance in filling new positions authorized and funded for the current rate year in the Company's last electric rate case.²⁶ As a general matter, the recommended decision proposed providing only 45% of the Company's requested funding associated with new positions.

DPS Staff takes exception, contending that its own proposal to provide only 40% of the funding requested for new

²⁶ Case 07-E-0523, Consolidated Edison Company of New York, Inc. - Electric Rates, Order Establishing Rates for Electric Service (issued March 25, 2008) (2008 Rate Order).

positions should be adopted instead.²⁷ DPS Staff maintains that the judges' proposed percentage failed to recognize that the Company's rate of filling new positions was lower in the fifth and sixth months of the current rate year than in the first four and that DPS Staff's own 60% downward adjustment was conservative.

The Company excepts, contending that the recommended decision's 55% downward adjustment failed to recognize the Company's expenditures on contractors retained to perform underground inspections in lieu of permanent employees. It also argues that the judges erred by giving the Company no credit for its expenditures for those positions filled before the start of the current rate year, in advance of receiving rate relief, which it claims amount to 47 full-time equivalents (FTEs).²⁸

The Company replies to DPS Staff's exception, arguing that focusing on just two months' experience in hiring would be unfair, fail to recognize the Company's need for flexibility in achieving annual budget goals and objectives for myriad programs, and undercut customer interests in adequate Company staffing.²⁹ In addition, the Company says that DPS Staff, like the recommended decision, does not take into account the Company's expenditures on contractors and overtime as a substitute for hiring.

DPS Staff answers the Company's exception noting that the Company provided no evidence of any costs for its claimed use of contractors or overtime, but simply attempts to shift its burden of proof to other parties. DPS Staff also accuses the Company of exaggerating the FTEs hired before the beginning of the current rate year, which amount to fewer than 29, not 47.³⁰

²⁷ DPS Staff BoE, pp. 6-7.

²⁸ The Company's BoE, pp. 9-12.

²⁹ The Company's B0E, pp. 3-5.

³⁰ DPS Staff's B0E, pp. 7-8.

The Company seizes on the recommended decision's recognition that the calculation of these employee labor expenses should take into account the use of contractors and overtime, but ignores the following remonstrance that this should be done "insofar as the record permits." The Company claims in brief that it hired 108 contractors instead of 108 new permanent employees that were funded for underground inspections for the current rate year because it realized "early on" that it could not fill the new positions on a sufficiently timely basis. This contention is not supported adequately by the record. The sole testimony on point is a single sentence by its Accounting Panel in rebuttal that: "The Company is using contract labor to complete this program" (Tr. 2297). The record is devoid of evidence of when the Company decided it could not fill the new positions on a timely basis, when it hired any contractor as a substitute for filling any new position, how many it claims to have hired, or what expenditures it claims to have made on contractors, compared to the funding allowed for permanent employees.

The Company claims the burden of proof was not on it to justify its requested funding level, but rather on DPS Staff to justify DPS Staff's adjustment, once the Company made its bare, unsupported declaration that it had hired some unidentified number of contractors at some unidentified time at some unidentified cost, in lieu of hiring 108 new employees. We do not accept that contention. The Company had the burden of proof to support its request for funding for the new positions, as well as the obligation to establish by competent testimony its detailed cost of service.³¹ Contrary to the Company's claim, DPS Staff met its obligation to seek discovery of the information underlying the Company's direct case. DPS Staff

³¹ PSL §66(12)(i); 16 NYCRR 61.1, 61.3(b)(1).

conducted discovery and provided testimony that--together with the Company's own responses to interrogatories and exhibits (e.g., Ex. 441)--clearly established that the Company had not hired many of the new employees for which it received funding in its last electric rate case and, given its hiring performance, would not incur the full level of expenses for new employees for which it seeks funding for the Rate Year.

The Company did not suggest in its responses to DPS Staff's discovery that it had substituted contract labor for the 108 new employee positions in question. Only on rebuttal did the Company raise the claim that it had used contract labor instead of hiring new employees. That bare statement in itself is unpersuasive and we find it unreasonable for the Company to assume that statement would be sufficient. If the Company had supporting evidence of incurring costs for contract labor for underground inspections, its accounting panel surely had access to that information and the Company should have provided it in a timely manner. It was incumbent on the Company to come forward with actual evidence of the expenditures it claims to have incurred in lieu of labor expense to perform the work the new employees were supposed to have performed. The Company has even less record support, moreover, for its claim that it used overtime as a substitute for hiring than it does for its claim about contractors.

The bottom line is that there are no cost data on the record from which we can determine the extent, if any, to which the Company used contract labor or overtime to perform work in lieu of the new employees for which funding was provided to perform that work. The Company claims that we now have the responsibility either to request information on alleged Company use of contractors and overtime, in order to calculate a hiring

adjustment, or to use a reasonable proxy.³² It cites no law, regulation, or precedent for that proposition, however, and we reject it.

Nor are we persuaded by the Company's suggestion that it should somehow receive credit for the costs incurred prior to the current rate year for 72 net positions filled before the current rate year began (and before we approved funding of them in current rates). The judges' recommended Company labor expense includes full Rate Year funding allowance based upon all 72 of those net positions. The Company maintains that Ex. 441 shows a total of 47 FTEs for those employees hired before the current rate year. This figure appears to be grossly overstated. The actual number appears to be 28.7 FTEs by our count, taking into account whether and when the positions were backfilled. Furthermore, funding equivalent to 16.5 of those FTEs was captured in the Test Year for this proceeding. In any event, the Company's costs prior to the current rate year associated with advance hiring of positions for the current rate year are irrelevant to the issue of how much funding the Company needs for payroll, benefits, and related costs of new positions expected to be filled over the course of the Rate Year. The Company incurred those costs voluntarily without any basis for assuming it could defer them and later recover them in rates. Furthermore, the Company has a large pool of available funds to pay the costs of those hirings, due to the fact its personnel hiring rate was below that authorized and funded in the 2008 Rate Order.

DPS Staff's own adjustment percent is a subjective one, interpolating from an adjustment factor of "56.07%" based on the rate of hiring over the first six months of the current rate year and a factor of "62.43%" based on the hiring rate over

³² The Company's BoE, pp. 10-11.

the fifth and sixth months. Its adjustment assumes that a lower rate of hiring will prevail over the second half of the current rate year than did over the first half (dropping from 13.3 per month to 8.8 per month), solely on the basis of the lower rate for the fifth and sixth months, and more heavily weights the rate in those two months. Month-to-month variation in the rate of hiring is to be expected. The six-month period used for the historic hiring adjustment is relatively short and does not reasonably lend itself to the degree of precision in forecasting inherent in DPS Staff's position. The Company's argument that management requires some flexibility in its rate of hiring over the course of a year is well taken. It would be unreasonable to expect the Company to maintain the same rate of hiring month after month throughout the course of the year.

We find it more reasonable to base the adjustment on the assumption that the overall hiring rate for the second half of the current rate year will be the same as that over the full first six months, as the recommended decision did. That assumption results in an allowance factor of 43.9% (56.1% downward adjustment), which the judges rounded to 45%, rather than DPS Staff's proposed 40% allowance (60% downward adjustment). We conclude that the record most reasonably supports the recommended decision's adjustment of 55%, i.e., a 45% allowance, for the Company labor expense for new positions.

2. DPS Staff's Department-Specific Adjustments

a. Electric (Distribution) Operations--Various

The Company sought funding for five new distribution engineer positions for various programs, including operations to mitigate risk of violent transformer failure by analyzing such items and factors as field-returned equipment, transformer failure root causes, and dissolved gas in oil. The recommended decision endorsed full funding for three of the five positions because they had already been filled, as well as 45% funding for

the other two positions, following the judges' historic hiring practices adjustment. In addition to its advocacy of only 40% funding based on historic hiring practices, DPS Staff excepts to the recommendation for full funding of three engineering positions. It maintains that, because its historic hiring practices adjustment was a global adjustment, funding known filled positions diminishes the effect of the adjustment. DPS Staff says consistent application of the recommended decision's approach would require recalculating the adjustment to exclude the effects of funding labor program changes for known filled positions.³³ The Company does not address this particular DPS Staff exception.

We agree that consistency calls for application of the historic hiring adjustment to the three newly requested engineering positions despite the fact that they are already filled. The historic hiring practices adjustment was a general adjustment that did not address when particular positions were filled, but only the Company's overall rate of hiring for all new positions. The judges' calculation of the historic hiring practices adjustment they recommended included credit for positions approved for the current rate year that were filled before the beginning of the current rate year. Thus, the historic hiring practices adjustment already takes into account that some new Rate Year positions are being filled before that year begins. We have already rejected DPS Staff's calculation of the historic hiring practices adjustment in favor of the recommended decision's. We therefore apply the judges' historic hiring practices percentage and will allow only 45% funding for all five of these distribution engineering positions, including the three that have been filled.

³³ DPS Staff's BoE, p. 57.

b. Electric (Distribution) Operations–Enhanced Project Planning

The Company requested funding for 12 positions for enhanced project planning. Rejecting DPS Staff's proposal to eliminate funding for all of the positions, the judges recommended an allowance of 45% based on the recommended decision's historic hiring practices adjustment. DPS Staff takes exception on the ground that the Company could not explain why existing personnel are unable to perform the work or why there is a shortage of manpower, and thus the Company has not demonstrated the new employees will provide added benefits.³⁴ The Company responds that the recommended decision fully considered the need for the positions and found the Company had provided sufficient evidence of need and steps to avoid duplication, and also that it would be difficult for the Company to prove the positions would not duplicate the work of existing employees.³⁵

The Company explained that the positions, comprising one supervisor and three project specialists in each of its three regional engineering sections, were requested due to expansion of the capital budget for electric distribution operations, as the Company performs more detailed analysis to design enhancements to the distribution system and meet changing demand and operating requirements. It maintains the increased staffing level is commensurate with the increased capital construction program in electric distribution and will facilitate completion of greater workload in project planning and oversight. (Tr. 3913-14; Ex. 169 (redacted), pp. 766-67.³⁶)

³⁴ DPS Staff's BoE, p. 8.

³⁵ The Company's BOE, pp. 5-6.

³⁶ As noted above, some exhibits are protected from public disclosure in whole or in part on an interim basis. In these instances, there are redacted, or public, versions and unredacted, or confidential, versions.

The judges' recommendation was not unreasonable in light of the arguments made to them by the parties. We have concern, however, about the sufficiency of the underlying justification for the Company's request. Over the period 2004 through 2007, the Company's capital expenditures for electric distribution rose from \$485.2 million to \$898.8 million [Ex. 169 (redacted), pp. 14-15]. In 2008, its actual expenditures in that category were \$1,041.7 million.³⁷ Capital expenditures for electric distribution peaked in that last year, however. In 2009, the Company forecasts that they will drop to \$996 million, then level off at approximately \$960 million in 2010 through 2012 (Ex. 51). The need for these enhanced project planning positions is predicated on an increase in the Company's capital expenditures on electric distribution, but in 2009 through 2012 those expenditures will actually be lower than they were in the year just completed. We conclude that the Company has not established its claimed need for the 12 positions. We will therefore disallow funding for those positions.

c. Shared Services--Programmers

The Company requested funding for a total of 14 programmers for its Shared Services unit, seven funded in the 2008 Rate Order and seven newly proposed for the Rate Year. The judges found that the 55% downward historic hiring practices adjustment should be applied to the seven newly requested positions, but recommended full funding for the seven positions approved in the Company's last electric rate case, all of which were filled before the end of the first quarter of the current rate year. DPS Staff takes exception to the recommendation for full funding of the seven positions previously funded in the 2008 Rate Order, on the same grounds it asserted in its exception to full funding of distribution engineering positions,

³⁷ The Company's December 2008 Monthly Financial Report, p.11.

discussed in IV(A)(2)(a) above.³⁸ The Company opposes DPS Staff's exception, declaring that the historic hiring practice adjustment, if allowed at all, should not apply to positions approved in the 2008 Rate Order that will be fully staffed before the Rate Year, such as these already-filled positions. The Company maintains that the adjustment was clearly formulated to measure the pace at which the Company may fill positions first approved by the Commission in this case.³⁹

We agree with the judges and the Company. Unlike the distribution engineering positions discussed in section IV(A)(2)(a) above, these seven programmer positions are undisputedly positions that were funded in Case 07-E-0523, not ones newly requested in this proceeding. We therefore deny DPS Staff's exception and adopt the judges' recommendation.

d. Other Normalizations

The Company sought full-year funding for positions in Public Affairs, Strategic Planning, Tax, and Environmental Health and Safety (EH&S) that were vacant all or part of the historic Test Year. The judges recommended adoption of DPS Staff adjustments to disallow funding for those positions because in brief the Company merely referred generally to update/rebuttal testimony of its accounting panel and another witness, with no reasoned argument in opposition to the proposed DPS Staff adjustments. The Company excepts in a similarly off-hand manner, merely claiming those positions were filled in early 2008 and referring to even less evidence.⁴⁰ DPS Staff opposes, stating that its adjustments did not track specific positions in each department; and, even if the specific positions in question have been filled, other positions in those

³⁸ DPS Staff's BoE, p. 7.

³⁹ The Company's BOE, p. 4.

⁴⁰ The Company's BoE, p. 16.

particular departments or other departments will be vacant during the Rate Year.

The Company's exception does not even address the EH&S positions with any reference to the record. For the remainder of the positions in question, the Company's exception argues only that they were filled in early 2008. The testimony to which it refers contradicts its argument, stating variously that some of the positions were filled in early 2008, some were filled later in the first half of 2008, and some had not been filled but the Company "expected" to fill them before the end of 2008 (Tr. 2309-12). Nothing in the testimony addresses whether any of the positions were filled by internal transfer and backfilled.

The testimony to which the Company refers also addresses the need for the positions in issue. Neither DPS Staff nor the judges questioned the need for the positions, only the degree to which the Company's overall requested funding for program change positions matched its historic practice in filling positions. To the extent that the positions were filled from external sources or filled internally and backfilled, they were credited in calculation of the historic hiring practices adjustment. There is insufficient persuasive evidence or argument in support of the Company's exception and we deny it.

e. State Regulatory Affairs

The recommended decision accepted the Company's request for funding seven new positions for a new State Regulatory Affairs Department (SRAD), subject to the 55% downward adjustment for historic hiring practices. DPS Staff excepts, arguing against any funding for the positions. It contends that the Company did not provide any substantive documentation in support of the request, disputes the Company's contention that the group is being developed in response to feedback from DPS Staff, and argues that the SRAD is a

discretionary program that could be deferred without affecting safe and adequate service.⁴¹ The Company counters that, before DPS Staff's brief on exceptions, DPS Staff never questioned the Company's Vice President's testimony that, among other things, the SRAD was developed in response to feedback from DPS Staff, testimony on which DPS Staff never sought discovery or cross-examination.⁴² In addition, the Company maintains that its witness' testimony explains the value of a regulatory affairs program for not only itself but its customers, in light of the growing complexity and criticality of regulatory matters.

DPS Staff's claim that the Company provided no substantive documentation in support of its request is difficult to fathom. There is substantial record evidence in support of the request (Ex. 364), which DPS Staff chose not even to cross-examine. Nevertheless, we are concerned that, although the SRAD might hold the prospect of some benefit, it is not a necessity for the Company. We see no reason why lack of an SRAD would adversely affect the Company's ability to provide safe and reliable service. Thus, we disallow funding for it.

f. Emergency Management

We denied the Company's request for incremental Emergency Management positions in the 2008 Rate Order, but indicated we would entertain a better-supported request for incremental costs. On March 3, 2008, the Company filed a Master Implementation Plan (MIP) in Case 06-M-1078 reflecting addition of 16 new positions, funding for which it requests in this proceeding. The judges recommended full funding and rejected DPS Staff's proposed adjustment to eliminate funding for all but

⁴¹ DPS Staff's BoE, pp. 8-9.

⁴² DPS Staff did not address that particular point on an anticipatory basis in its initial brief, although the Company witness had testified to it (Ex. 364, pp. 5-6), and did not discuss the SRAD at all in its reply brief.

three of the new positions. DPS Staff takes exception, on the basis that the Company has failed to demonstrate its incremental costs for the positions. It notes that, as of December 8, 2008, four of the new positions had not yet been filled; and that the record lacks any evidence of the extent to which nine of them have been filled by internal transfers and, if so, the extent to which the vacated positions have been backfilled.⁴³ In essence, DPS Staff argues that only positions filled externally, or filled internally with vacated positions backfilled, by December 8, 2008, can serve as proof of incremental costs the Company can reasonably be expected to incur in the Rate Year.

The Company contends that DPS Staff's proposed adjustment is unreasonable because: the Company is filling the questioned positions in the current rate year at its own expense, in advance of funding in rates; the recommended decision finds the Company has made significant progress in filling the positions and is likely to fill them all by the beginning of the Rate Year; and the Company is filling the positions in accordance with its MIP (Tr. 242-43).

DPS Staff agrees that all 16 incremental emergency management positions are needed (Tr. 2848-50). The positions are included in the Company's MIP filed in compliance with our directive.⁴⁴ The Company's testimony and exhibits in this case explain the MIP in detail, including how the new emergency management unit would be organized and would function, how it would be staffed, including existing positions and positions moved from other units to it, and incremental costs (Tr. 192-95,

⁴³ DPS Staff's BoE, pp. 11-13. DPS Staff also suggests that, if we do allow all 16 positions requested, we apply the historic hiring practices adjustment to them. *Id.*, n. 7.

⁴⁴ Case 06-M-1078, Consolidated Edison Company of New York, Inc. --Performance Audit of Outage Emergencies Response, Order Directing Submission of an Implementation Plan (issued January 17, 2008)(Emergency Management Order).

204-28; Ex. 74-80). DPS Staff testified that the Company is on target in fulfilling the recommendations of the Vantage Consulting, Inc. independent audit of the Company's emergency outage response program and the requirements of our Emergency Management Order (Tr. 553-65). The only issue currently outstanding on compliance with either the Emergency Management Order or our directive on justifying incremental funding for the program is the question of emergency management staffing.

The essential issue here, as we see it, is the same one we discussed for the distribution engineering positions in IV(A)(2)(a) above. For positions newly proposed for the Rate Year, consistency demands that we apply the historic hiring practices adjustment regardless of whether some particular positions have been filled already. In addition, the historic hiring practices adjustment takes into account the extent to which hirees came from internal sources and, if so, the extent to which vacated positions have been backfilled. DPS Staff's proposal amounts to an allowance of less than 20% of the funding for these emergency management positions, which is inconsistent with even its own calculation of the historic hiring practices adjustment. The Company's exception and the recommendation of the judges do not recognize the general applicability of the historic hiring practices adjustment notwithstanding whether some or all of the positions have already been filled. Consequently, we deny DPS Staff's and the Company's exceptions. We will apply the judges' recommended historic hiring practices adjustment to these 16 emergency management positions and allow 45% of the requested funding for them.

g. Gold Program

The Company requested funding for its 18-month long Growth Opportunities for Leadership Development (GOLD) Program, which gives newly hired college graduates the opportunity to become future Company leaders through rotational job experience.

DPS Staff noted that the Company's request did not reflect attrition the program has historically experienced. It maintained that the historical data supported an average attrition rate of nine percent per six-month segment of the program, or 18% annually. The judges found that DPS Staff had used only the two highest attrition rate class periods from five class periods of historical data in developing its proposed attrition rate. They recommended an adjustment using an average attrition rate of 14%, based upon all five class periods of available data. DPS Staff takes exception, denying that it selected the highest attrition class periods to calculate its proposed rate and claiming that it simply used the most recent and consistent data available, excluding outliers that skew the average.⁴⁵

The Company replies that DPS Staff's approach in fact rejected relevant data, ignored the most recent data available, and is one of a number of examples of DPS Staff's inconsistent approach to determining historical averages, in terms of numbers of years to consider and use of "judgment" in making adjustments to historical periods.⁴⁶

Out of five class periods of available data, DPS Staff based its "historical average" on the two class periods with the highest attrition levels, those for 2005 and 2006 (Tr. 2468). DPS Staff's brief on exceptions claims there is no record basis for selecting a five-year average, because the data incorporate only four 18-month GOLD classes that have completed the program. This claim can only reasonably be interpreted to mean that DPS Staff considers the 2007 class data unusable, because that class has not completed the program. DPS Staff also rejects the 2003 class data as "inconsistent with the most recent attrition rates." Nonetheless, it then cites both the 2003 and the 2007

⁴⁵ DPS Staff's BoE, pp. 13-14.

⁴⁶ The Company's BOE, p. 6.

rejected class data (along with those for the 2005 and 2006 classes) as demonstrating that 2004 class data should also be rejected because significantly lower.

DPS Staff rejects the 2003 and 2004 class data as lower than the "most recent" data, meaning those for the 2005 and 2006 classes. As the Company points out, DPS Staff provides no explanation of why the 2003 and 2004 class data are the "outliers" and the 2005 and 2006 class data are not. DPS Staff also, in fact, threw out the "most recent" data, those for the 2007 class. But it provides no explanation for why the 2007 class data should be excluded from the calculation entirely, rather than filled out by extrapolating the final six-months' attrition from the attrition experience over the first twelve months of the class period.⁴⁷

DPS Staff also inconsistently claims only now, on exceptions, that 2007 is a "representative" year and suggests that it calculated its proposed attrition rate with the 2007 class year data included, resulting in a 9% per six months average attrition rate for the class years 2005 through 2007 that supports its proposed adjustment.⁴⁸ But if the 2007 class year data were included in the average with 2005 and 2006 class year data, the six-month average attrition rate would, in fact, have been 8%, not DPS Staff's 9%; and the annual attrition rate would have been 16%, not DPS Staff's 18%. Moreover, as noted above, DPS Staff actually testified that its attrition rate was based on the 2005 and 2006 class year data. Thus, DPS Staff's claim in brief that its attrition rate calculation included the 2007 partial class data is contrary to the record. (It is, in

⁴⁷ Such an extrapolation admittedly would amount to the same thing as just using the actual attrition rate experienced for the first year for the 2007 class.

⁴⁸ DPS Staff's BoE, p. 14.

fact, contradicted on the prior page of DPS Staff's brief, where DPS Staff rejects the use of that partial-program data.⁴⁹)

DPS Staff's exception is denied. The record supports the recommended decision's attrition rate adjustment for the GOLD Program and we adopt its recommendation.

B. Productivity Adjustments

The Company proposed a productivity imputation of 1% (\$10.6 million), with which the recommended decision agreed. The judges concluded that the Company had sufficiently explained how expected productivity savings had been reflected in the Rate Year revenue request to the extent practical and why opportunities for material productivity increases in excess of the 1% imputation typically applied were not likely from new programs. They accepted the Company's contentions that much of its new investment reflected increases in material costs or adding new facilities that would require greater inspection, maintenance, and repair; and that the productivity of significant numbers of new employees would be lower initially, pending training. The judges also agreed that most of the productivity gains from expenditures over the last five years would be captured in Test Year spending levels. They found insufficient record basis to conclude that productivity gains of 2% or 3% were likely to be realized in the Rate Year. The judges also explained that, if there were additional productivity gains over the 1% level, the Company would have the incentive to capture them in the short run, which would benefit ratepayers for the long term. They also noted that in these circumstances limiting the productivity imputation to 1% would leave the Company with some minimal upside earnings potential.

⁴⁹ "[T]here is no record basis for selecting a five-year average; the data provided by Con Edison only incorporates four year's [sic] of GOLD program classes that have actually completed the program." Ibid., p. 13.

The judges believed such a result would be consistent with their overall conclusion that a rate plan that recognizes minimal reasonable costs, reasonably minimizes Company downside exposure, and does not eliminate all upside earnings potential is advisable in light of economic uncertainty, relatively high capital costs, the Company's large construction program, and the benefit of preserving the Company's credit rating.

1. Positions of the Parties

DPS Staff and the NYC Government Customers take exception, supporting productivity imputations of 2% (an additional \$10.6 million over the 1% level) and 3% (\$21.6 million more than the Company), respectively.⁵⁰ Both parties ground their recommended imputation levels on the recent and proposed substantial increases in the Company's investments in infrastructure and electric O&M, which they contend will provide significantly increased opportunity for productivity savings beyond the 1% typical imputation. They note the Company's concession that its rate filing did not specifically identify and quantify productivity savings from its capital and O&M programs in most circumstances (e.g., Tr. 4161). Although they acknowledge that some of the productivity gains from capital and O&M expenditures over the recent years will have been captured in Test Year data, DPS Staff and the NYC Government customers maintain that historic investments and continuing expenditures through the subsequent 27 months of Linking Period⁵¹ and Rate Year will produce additional unidentified and unquantified savings, for which the productivity imputation is designed to provide a surrogate. DPS Staff does not rest its position on any specific analysis of the

⁵⁰ DPS Staff's BoE, pp. 14-16, and the NYC Government Customers' BoE, pp. 8-14.

⁵¹ The "Linking Period" is the 15-month period from the end of the Test Year to the beginning of the Rate Year.

Company's capital and O&M expenditure proposals, but the expectation that those investments will increase reliability, enhance customer service, and increase operational efficiency. The New York City Government Customers point to their witness' identification of specific projects and programs, amounting to about \$500 million in capital and \$100 million in O&M expenditures in the Rate Year, that could provide the opportunity for increased productivity. The NYC Government Customers also argue that the recommended decision held to a 1% productivity imputation in order to give the Company an opportunity for excess earnings.

The Company opposes both DPS Staff's and the NYC Government Customers' exceptions.⁵² The Company contends that DPS Staff does not support its proposed productivity figure with any study, data, or even example, nor does it identify the extent to which reduced costs would occur in the Rate Year. It challenges the NYC Government Customers' analysis of projects and programs as superficial, comprising review of Company white papers and noting next to their titles which ones their witness concluded would have some potential for producing savings in the Rate Year. The Company argues that much of the increased spending is driven by increased costs for materials and by expansion of facilities to meet load growth, neither of which would increase productivity opportunities. It notes that additional facilities for load growth, rather than increasing efficiency, add to work load and the need for inspection, maintenance, and repair. The Company also says its employee turnover, with substantial numbers of newer employees replacing more experienced retiring personnel, lowers productivity initially, pending training.

⁵² The Company's BOE, pp. 12-18.

2. Discussion

DPS Staff's and the NYC Government Customers' contentions over whether the Company has adequately identified productivity savings specifically in its rate request are not particularly relevant. The usual 1% productivity adjustment applies in the absence of clear and convincing evidence that potential productivity improvements have been factored into a company's forecast of rate year operations.⁵³

The arguments back and forth among the parties, as well as the evidence in the record, tend toward the qualitative rather than quantitative. This is unsurprising, given that the productivity imputation is intended to substitute for identifiable, quantifiable savings. DPS Staff's proposal is based on the position that 1% imputations have been applied during "normal" infrastructure investment times, while the Company's investment levels have been considerably higher over recent years than in the past and will continue to be so over the next five years. DPS Staff considers a single percentage point increase in the imputation, to 2%, to be a conservative means to recognize the potential from the increased level of investment, but it is not directly linked to any specific analysis of recent or projected Company infrastructure investment.

The NYC Government Customers have identified particular projects and programs where they think productivity gains can be achieved, and there are identifiable Company investment levels associated with those projects and programs. Even conceding that some savings might be achievable from those projects, however, there is no way to extrapolate the extent to which any savings that might arise would fall within the typical 1% imputation or might materially exceed that level --

⁵³ Case 27567, Spring Valley Water Company, Inc. -- Water Rates, Opinion No. 80-16 (issued April 24, 1980), p. 14.

especially approaching a 200% increase over that level. The NYC Government Customers' witness merely constructed a table showing each new Company project or program and, if the associated Company white paper mentioned any possibility of greater reliability or efficiency, labeled that project or program as a source of additional productivity, but with no analysis of the amount of savings that might be realized from any particular project or program.

Some of the productivity savings from increased investment in the years prior to the Test Year should have been captured in Test Year expenses. Nonetheless, a significant portion of investment in those prior years, plus expenditures in the Linking Period and the Rate Year, can reasonably be expected to provide substantial additional productivity gains in excess of the 1% imputation level. The Company argues that potential should be discounted somewhat for higher material costs and expansion of facilities to meet new load, but it too sheds no quantitative light on the issue. In our judgment, increasing the productivity imputation to 2% will reasonably reflect both the increased levels of investment and the discount for higher material costs and expansion of facilities for new load, even without expecting greater productivity from workforce expansion.

The Company argues that, if it does realize productivity savings greater than 1% in the Rate Year, it will retain the benefit of the additional savings only for the short term, after which they would be captured in a test year and soon begin redounding to the benefit of ratepayers for the long term. Consumers faced with current harsh economic realities will find the prospect of savings two or three years down the line, after the crisis may have passed, of small comfort, and no help in paying their bills now. Fair and reasonable rates should be fashioned in a way that better reflects the existing harsh economic environment and requires the Company, as a good

corporate citizen, to act in ways that better contribute to improving that environment and demonstrate a commitment to operating as efficiently as possible in providing electric delivery service. We conclude that, in addition to reflecting the Company's greatly increased capital investment levels, a 2% productivity imputation will help achieve that goal and better balance the interests of ratepayers and the Company.

C. Labor Escalation

1. Wage Progression Increases

The Company's union employees receive wage progression increases twice a year until they reach the top of pay grade. The judges recommended adoption of DPS Staff's proposal to disallow \$6.998 million in union employee wage progression increases for the Rate Year. They found DPS Staff had clearly established that the Company overstated its costs of wage progression increases, because it applied the costs of those increases to all union employees, even though many of those employees indisputably are at the top of grade and do not receive progression increases. They also agreed with DPS Staff's argument that annual savings from one employee retiring at the top of grade could offset the annual wage progression increases of several employees who have not yet reached that level. The recommended decision found that the Company had made no effort to provide evidentiary support for a reasonable level of wage progression increases to include in its cost of service and that progression increases should therefore be excluded from calculation of the labor escalation rate.

The Company excepts.⁵⁴ It claims that its rate filing included two wage progressions for all union employees who have not reached their maximum salary levels. The Company maintains DPS Staff's theory, accepted by the recommended decision, that

⁵⁴ The Company's BoE, p. 13.

retirements will offset the costs for replacements and their progressions is unsupported on the record. It also contends that most union employees hired over the last several years are not near their maximum pay rate, and that more union employees are being hired than are leaving, with their ranks increasing by 10% from 2004 through August 2008.

DPS Staff opposes the Company's exception.⁵⁵ It contends that the Company's labor escalation calculation included wage progression increases for all union employees, both those who have already reached the maximum pay level and those who have not, thus overestimating the costs of wage progression increases. DPS Staff argues that although the Company says it has hired about 3,000 new employees receiving wage progressions, it has failed to provide the number of union employees who have already reached the top of grade and will not receive progressions. It also agrees with the recommended decision that the Company had the obligation to establish for the record the reasonable level of wage progressions to include in its cost of service, but did not even attempt to do so.

We note initially that the Company has not disputed DPS Staff's testimony that the vast majority of wage progression increases do not represent incremental costs for the Company. They are included in the Test Year labor cost (Tr. 2673-74). Nonetheless, the Company states in its brief on exceptions that, at very least, its rate filing also "included two annual wage progressions for all union employees that have not reached the maximum salary in their title." If this contention is intended to mean that the Company included progression increases for only those employees, it is not correct. DPS Staff has correctly pointed out that the Company's filing applied progression increases to the average union salary at December 2007 (Ex. 5,

⁵⁵ DPS Staff's BOE, pp. 8-11.

Sched. 2, p. 4), then multiplied that average salary by the entire number of union employees projected for the Rate Year (ibid., p. 2). The Company's own exhibit demonstrates that it included wage progression increases for all union employees, including those at the top of their pay grades and thus ineligible for progression increases. The Company acknowledged that about one-third of its employees are eligible for retirement (Tr. 371). It has not taken issue with DPS Staff's contention that most of these employees can reasonably be assumed to be at the top of pay grade and ineligible for wage progression increases.⁵⁶ For these reasons, the record clearly shows the Company's rate request overstates the wage progression costs that it will incur in the Rate Year.

The Company is correct that the recommended decision erred in finding the record sufficient to support DPS Staff's attempted demonstration that savings from one retiree being replaced by a new employee would be sufficient to offset the two annual wage progressions for 12 employees. The record does not in fact establish that Company union employees reach the top of grade in twelve years. Still, DPS Staff's argument is correct as a general matter, because it is reasonable to assume that employees take at least several years to move from the bottom of pay grade to the top and that retirements and other vacancies of union employees at top of grade are virtually certain to offset all incremental wage progression increases.⁵⁷

To sum up, the record clearly establishes that the Company's rate request includes wage progression costs it will not incur because (1) they double count progression increases already captured in the Test Year and (2) they are calculated for employees at the top of grade who are ineligible for progressions. In addition, the record supports the reasonable

⁵⁶ DPS Staff's Initial Brief, p. 73.

⁵⁷ See Appendix III, Wage Progression Increases Example.

conclusion that the Company will experience savings from employees leaving the Company at top of salary grade that will more than offset the costs of wage progressions for new hires, even with an increasing union workforce. We deny the Company's exception.

2. End of Test Year Employment Count

In developing its labor escalation rate, the Company used its employee count for December 2007, the last month of the Test Year, to calculate Rate Year payroll costs. The recommended decision endorsed a DPS Staff adjustment (a \$5.153 million reduction)⁵⁸ to use the average Test Year employee level to calculate Rate Year payroll. The judges found use of the average employee count for the Test Year more reasonable than use of just the average count for the last month of the Test Year in determining the labor escalation rate, because the Company's cost of service and resulting rates are to be established for the entire Rate Year, not just the ninth month (December) of the Rate Year. The judges also found persuasive DPS Staff's contention that the Company's labor expense proposal for the Rate Year represents almost a 26% increase over the Test Year level, far out of line with the Company's average labor expense increase of less than 1% from 2004 to 2007.

The Company takes exception, contending that, because its employee count has been rising consistently over the past several years, the year-end count for the Test Year provides a more current, informed, and accurate representation of the number of employees during the Rate Year than does the average count for the entire Test Year.⁵⁹ It maintains that using the 12-month average Test Year count will deny it Rate Year funding for the 143 employees comprising the difference between the one-

⁵⁸ DPS Staff's BOE, p. 10.

⁵⁹ The Company's BoE, pp. 14-15.

year average count and the end of Test Year count, who it states will likely be employed throughout the Rate Year.

DPS Staff counters that using the average number of employees for the full Test Year, rather than just one particular month, more accurately reflects the Company's payroll costs for the entire Rate Year.⁶⁰ Using the average for the entire year, DPS Staff asserts, better tracks fluctuations that occur in the Company's staffing level over the course of each year, including the Test Year and the Rate Year. It argues that because the actual employee count fluctuates over the course of the year and reaches its highest level in December, using the December employee count will produce an overstated rate allowance.

As the recommended decision states, we are determining the cost of delivery service and resulting rates for the entire Rate Year, not just one particular month. The Company's approach assumes that its payroll will remain at a constant level, the highest level experienced in any month of the Test Year, for the entire Rate Year. The Company's exception argues only that the 143 additional employees reflected in the December 2007 count, but not the average Test Year count, are "most likely" to remain employed over the whole Rate Year. In fact, the Company's payroll will fluctuate over the course of the Rate Year as employees are hired or leave the Company's employ, just as it does every year. The use of an average count for the Test Year as a whole would better track that fluctuation, which includes the overall growth in employment on which the Company's position relies. We deny the Company's exception.

D. Normalization (Vacancy) Adjustment

The Company made a normalization adjustment to provide full Rate Year funding for some of the positions vacant during

⁶⁰ DPS Staff's BOE, pp. 10-11.

the historic Test Year. The judges recommended adoption of a DPS Staff counter-adjustment eliminating the Company's adjustment. They found that the Company admitted its normalization would provide funding for positions that were vacant for up to 11 months of the Test Year, if those positions were not vacant in the final month, which would in effect require ratepayers to fund non-existent costs of vacant positions. The judges also agreed with DPS Staff that average attrition in the Test Year should be reflected in the attrition predicted for the Rate Year and that the Company's adjustment failed to take sufficient account of attrition. They noted DPS Staff's citation of record evidence that the Company can be expected to experience about 1,000 vacancies during the Rate Year, which will continue about two months on average. The savings for those vacancies over that average period would amount to Rate Year savings of more than \$12.8 million, much greater than the Company's vacancy normalization adjustment, which is about \$7.3 million, or \$7.9 million after escalation. Finally, the judges stated that they were not convinced the effects of the current economic downturn and Company efforts to attract and retain employees would eliminate or reverse such a large differential.

The Company takes exception.⁶¹ It contends that its normalization does not attempt to capture all positions vacant in the Test Year, but only those filled by the end of the Test Year, which it argues are likely to remain filled through the end of the Rate Year. Although the Company acknowledges that its normalization would provide funding for positions vacant up to 11 months during the Test Year, it states that the normalization would also deny it funding for some positions that were filled for most of the Test Year, so long as they were

⁶¹ The Company's BoE, pp. 15-16.

vacant in the last month. Thus, it argues, some, but not all of the Test Year vacancies will be filled during the Rate Year and the Company is entitled to funding for them. The Company also repeats its argument that attrition should be lower in the Rate Year than the Test Year because of its steps to attract and retain employees and recent experience that the economic situation is causing employees to stay longer.

DPS Staff opposes the exception.⁶² It agrees with the recommended decision's findings that average attrition in the Test Year should be reflected in the Rate Year and that the approximately 1,000 vacancies the Company can be expected to experience in the Rate Year will provide savings significantly greater than the amount of the Company's normalization. DPS Staff adds that the Company's Rate Year labor forecast fails to take attrition and related labor expense savings for the Rate Year into account at all. It also states that there is no record evidence demonstrating how the Company's normalization level was determined, whether for positions vacant for 11 months of the Test Year but filled by the last month, or, as the Company now argues, for those filled for most of the Test Year but vacant in the last month. DPS Staff dismisses the Company's argument about the economic downturn leading to employees staying with the Company longer, because the only record evidence it cites relates solely to GOLD Program associates, not to Company employees generally. As for the Company's argument about its efforts to attract and retain employees, DPS Staff says those steps come with costs reflected in the revenue request and reiterates the recommended decision's finding that those efforts and the economic downturn are insufficient to eliminate the differential between the Company's normalization and the savings it will realize from vacancies in the Rate Year.

⁶² DPS Staff's BOE, pp. 11-13.

The Company claims on exception that its normalization seeks to capture only those positions filled by the end of the Test Year. Its reply brief to the judges, however, stated that it also included some additional positions.⁶³ Moreover, the Company provides no citation to the record to back up its claim that its normalization would deny funding for some positions that were filled for most of the Test Year if they were vacant during the final month. There does not appear to be any record basis for the claim. DPS Staff's point that there is no record evidence demonstrating how the Company's normalization was determined is correct.⁶⁴ Its argument that the Company's Rate Year labor forecast does not take attrition or resulting savings into account is also correct.

The Company does not challenge the recommended decision's finding that the Company can be expected to realize \$12.8 million in savings from attrition during the Rate Year, far more than necessary to offset its \$7.9 million normalization adjustment, except to argue that the recommended decision should have given greater weight to the Company's claims that its efforts to attract and retain employees and the economic downturn will cut into the attrition level. DPS Staff correctly observes that the Company's testimony about experience with the effect of the economic downturn in reducing attrition relates only to the GOLD Program. Although the current economic turmoil might create some additional incentive for employees to stay longer than they otherwise would have, the Company's normalization amount is 38.3% less than the amount of savings it

⁶³ The Company's Reply Brief, p. 38.

⁶⁴ The Company's Initial Brief, p. 92, also claims that a list of normalizations at Tr. 2308 "demonstrates that the requested amount for vacancies is less than the actual level of vacancies" in the historic Test Year. There is no such list at that transcript page or that section of the Company's accounting panel's testimony, nor does Exhibit 274, referenced at Tr. 2308, contain any such list.

can be expected to realize from attrition in the Rate Year, based upon the attrition level experienced in the Test Year. The Company's claim that the results of its efforts to attract and retain employees and the current economic situation will cause a reduction in attrition is unquantified and entirely subjective. That those factors would produce nearly a 40% drop in attrition appears highly unlikely and thus unreasonable to assume. We adopt the judges' recommendation.

E. Variable Pay

The recommended decision concluded that funding the Company sought for its incentive variable pay plan for non-officer managers should be disallowed. The judges found nothing inherently wrong with an incentive pay plan from the ratepayer's perspective, but that the key questions were how a plan is designed and what implications it holds for the interests of ratepayers compared to those of stockholders. They considered the view that a variable pay incentive plan must be justified by specific, quantifiable productivity-associated savings inconsistent with the productivity imputation, which assumes many types of efficiencies occur in a utility's operations that are by nature difficult or impossible to identify and quantify specifically. They also noted that the Company's variable pay plan included several performance indicators that address goals for safety, environmental protection, and customer service that cannot readily be measured by dollar savings, as well as targets that further Commission performance requirements for reliability and customer service that benefit ratepayers.

The recommended decision favored disallowing funding for the Company's variable pay program, however, because it is focused predominantly on achievement of a net income target. The judges explained that, regardless of performance on other measures, no manager receives any variable pay whatsoever unless the Company meets or exceeds 90% of its internally generated

annual net income target. They found the net income factor overwhelms all other performance measures, benefits shareholders in the near and long terms, and holds only the possibility of some eventual benefit for ratepayers. They also noted that if the variable pay plan is funded and the Company misses the net income mark, all the funds go unspent and inure to the benefit of shareholders. For all these reasons, the judges recommended disallowance in this proceeding, but suggested that the Company might modify the plan to focus on benefits to ratepayers if it expected ratepayers to bear the cost of the plan in the future.

1. Positions of the Parties

The Company takes exception to the judges' recommendation.⁶⁵ It claims that the judges found the variable pay plan to be a reasonable and necessary business expense incurred to provide safe and adequate service. The Company then argues contradictorily that: (a) having found some of the plan's performance indicators would benefit ratepayers, the judges erred in failing to recommend allowance of at least some of the plan's costs; but (b) it is improper to try to segregate and quantify customer and shareholder benefits of the plan, citing *Abrams v. Public Service Commission*.⁶⁶ In addition, the Company maintains that the net income factor also provides benefits to ratepayers, because operating well financially shows investors and customers the Company is managing the business well and

⁶⁵ The Company's BoE, pp. 17-20. In a letter dated March 25, 2009, addressing updates to several expense items, the Company indicated it was withdrawing its request for variable pay, but would revise its plan and seek funding in future cases. The parties' exceptions are therefore moot. We discuss the recommended decision and exceptions regardless, to clarify our position on the issues raised and provide guidance for the future.

⁶⁶ 67 NY 2d 205 (1986). The Company cites the case generally, without reference to any particular point in the decision that it believes supports its argument.

focusing on costs and quality of service, and mitigates size and frequency of rate requests, as well. The Company also contends that eliminating the net income target could cause employees to focus exclusively on performance targets at an unreasonable level of cost, resulting in higher future rates. In any event, the Company insists, it should be allowed recovery of 35%-50% of variable pay plan costs to reflect the 30% of the plan that relates to non-financial targets, plus a portion of the remainder related to financial measures. In the alternative, it proposes that it be allowed the opportunity to submit a modified plan, responding to the judges' concern with the net income threshold, in this proceeding, so that it could implement the plan for the Rate Year.

DPS Staff opposes the Company's exception.⁶⁷ It disputes the Company's contention that the recommended decision found the variable pay plan to be a necessary business expense. DPS Staff argues that the *Abrams* case dealt with cost recovery for an abandoned capital project, not discretionary incentive programs, and affirmed the Commission's broad discretion to consider all relevant factors and use a wide variety of methods to achieve just and reasonable rates balancing ratepayer and investor interests. In addition, DPS Staff disputes the claim that meeting the net income target demonstrates to investors and customers that the Company is managing its business well and controlling costs to mitigate the size and frequency of rate requests. It points to the judges' findings that higher earnings over the three years ended March 31, 2008, were not the result of productivity gains, but likely due to higher than forecast sales, as a result of warmer than normal weather, and

⁶⁷ DPS Staff's BOE, pp. 14-17.

over-recovery for property taxes.⁶⁸ DPS Staff adds that the frequency and size of the Company's recent and anticipated electric rate requests belie its claim.

NYECC also opposes the Company's exception.⁶⁹ NYECC agrees with the recommended decision that the plan is designed to benefit shareholders primarily and therefore should be funded by shareholders, not ratepayers. Like DPS Staff, NYECC argues that the *Abrams* case is inapposite. It contends that *Abrams*, in fact, runs counter to the Company's argument and underscores that this Commission has broad discretion to consider those factors it finds relevant, ignore those it judges not so, and give each factor the weight it deems proper.⁷⁰

DPS Staff itself excepts to two of the judges' conclusions.⁷¹ First, it protests the judges' finding that requiring any variable pay plan to be justified by specific, quantifiable productivity savings reflected in the cost of electric delivery service is illogical and unreasonable in light of the productivity imputation, which seeks to capture savings difficult to identify and quantify. DPS Staff maintains this requirement is a matter of Commission policy, because variable pay plans related to financial parameters can be used to increase shareholder returns, driving cost cutting measures that improve short-term profitability but threaten negative service and financial effects for customers in the long run, citing the

⁶⁸ R.D., p. 79. The recommended decision accepted the Company's contentions on the reasons for higher than forecast earnings, including the argument that productivity was unlikely to have caused the over-earnings because its O&M expenses were also higher than forecast in those years.

⁶⁹ NYECC's BOE, pp. 2-4.

⁷⁰ Citing 67 NY 2d at 211-212.

⁷¹ DPS Staff's BoE, pp. 14-19.

opinion in Case 90-G-0734.⁷² There, the Commission stated that, if the goals of a utility's incentive compensation plan relate to financial parameters and are met, cost savings not reflected in the revenue requirement will offset plan costs and make it self-supporting, thus giving the company a windfall at ratepayer expense. Here, DPS Staff says, the net income factor in the Company's plan dominates all other elements, providing an incentive to managers to improve financial performance in ways that might not benefit ratepayers, but run counter to their interests. Second, DPS Staff objects to the judges' invitation to the Company to revise the plan in a way that solves the problem with dominance of financial goals rather than targets that will benefit customers, because this proceeding is too far advanced to allow the Company to do so without denying due process to other parties. DPS Staff notes that we denied funding for the identical variable pay plan in the Company's last electric case, but, rather than redesign the plan to satisfy concerns identified in the 2008 Rate Order, the Company simply recycled the program funding request here.

The Company opposes DPS Staff's exception.⁷³ Beyond repeating its arguments in support of its own exception, the Company adds, first, that DPS Staff misinterprets the National Fuel Gas opinion. The Company distinguishes that case on the ground that here its variable pay plan is tied to several operating performance indicators, rather than just financial parameters. It also argues that, because of operating targets that can provide benefit to ratepayers, disallowing all costs of the Company's plan will unjustly benefit ratepayers. The Company takes the position that insisting the variable pay plan be self-supporting based on specific, quantifiable productivity

⁷² Case 90-G-0734 et al., National Fuel Gas Distribution Corp. - Rates, Opinion 91-16 (issued July 19, 1991), pp. 7-8.

⁷³ The Company's BOE, pp. 18-22.

savings ignores the performance parameters that the judges see as furthering customer interests but not readily measurable in dollars saved. It claims that the mix of financial and performance goals in the plan keeps managers focused on meeting reliability, safety, and customer service targets in a cost-effective manner and on achieving budget goals reflected in its revenue requirement, rather than on cost savings beyond those reflected in the revenue requirement.

2. Discussion

The Company is wrong when it states that the recommended decision found its variable pay plan to be a reasonable and necessary business expense in providing safe and adequate service. The judges found only that performance incentive plans are "a common means to improve corporate performance and competitiveness." Nothing in the recommended decision suggests that the Company's particular incentive pay plan, in its current form, is either reasonable or necessary, or even that it contributes to safe and adequate service, although the judges did note some positive aspects to the plan. That the recommended decision noted some of the performance indicators in the plan could benefit ratepayers does not warrant any cost allowance for the Company. Assuming that those criteria could provide ratepayer benefit, what remains is an enormous net income hurdle that must be overcome before customers could benefit from any of the other features of the plan. If the Company believes it would be unjust for ratepayers to benefit from some features of the plan without bearing a portion of the plan's cost, nothing requires it to continue the plan in its current form.

The Company's reliance on the *Abrams* case for the proposition that we may not segregate and quantify ratepayer and shareholder benefits of the variable pay plan not only erroneously rests on the ground that the judges found the plan

reasonable and necessary, but is seriously misplaced in any event. As DPS Staff and NYECC maintain, *Abrams* confirms this Commission's broad discretion to weigh and apply any of a wide range of factors and methods if the end result provides just and reasonable rates, balancing the interests of ratepayers and shareholders.⁷⁴ The Company's argument that the net income target benefits ratepayers as well as shareholders is not persuasive. There is no assurance ratepayers will receive any benefit whatsoever from the Company achieving its net income target.

The Company's own arguments on the productivity imputation are instructive. As DPS Staff points out, the Company maintains that its overearnings to the tune of \$100 million a year in the rate years ending in 2006 through 2008 were not the result of Company excellent performance in enhancing productivity, but its good fortune in experiencing lower property taxes than forecast and warmer weather that drove higher sales than forecast, even in the face of higher O&M expenses than forecast. Those results certainly benefited shareholders. They provided no short- or long-term customer benefits, however, and did nothing to demonstrate the Company was managing its business well. Moreover, those results did nothing to show the Company was controlling costs to mitigate the size and frequency of rate increases, because two successive large rate increase requests followed immediately on their heels. In addition, as the recommended decision points out, if the Company fails to meet the net income threshold, none of the funding for the variable pay plan goes to benefit ratepayers. Rather, it inures entirely to the benefit of shareholders.

The Company's argument that the mix of performance and financial parameters in its plan keeps its managers focused on

⁷⁴ 67 NY 2d at 211-212, 215.

meeting operating parameters that benefit ratepayers in a cost-effective manner also fails. For one thing, the Company's explanation of the reasons for its overearnings experience during the rate years ending in 2006 through 2008 shows the weakness of its claim. In addition, the net income threshold for receiving any incentive pay ensures that managers will see meeting that threshold as more important than achieving any of the operating goals, especially since a maximum of only 30 percent of the potentially achievable pay depends on meeting the non-financial targets.

To the extent that the recommended decision holds out the prospect that a variable pay incentive plan including financial parameters, such as the net income factor, if properly structured and balanced with performance factors that promote reliability, safety, good environmental stewardship, and good customer service, might be acceptable, it is inconsistent with the policy set forth in the National Fuel Gas case. The Company's contention that National Fuel Gas does not apply in this case because its plan is not based exclusively on financial parameters is not correct. Nothing in the National Fuel Gas decision suggests it is limited in such a way, rather than applicable to any plan that includes financial parameters. Moreover, given the dominance of the net income parameter in the Company's variable pay plan, it is based nearly exclusively on financial parameters, suffers the same defects, and should be treated identically. If it was not clear before, we note that the National Fuel Gas policy that such plans must be self-supporting through productivity savings or financed by shareholders applies to any incentive plans that include financial parameters.

On the other hand, DPS Staff's position goes beyond the policy in National Fuel Gas. DPS Staff has taken the position in this proceeding that any incentive pay plan must be

self-supporting, with specific, quantifiable savings reflected in a utility's cost of service. National Fuel Gas requires such a demonstration only where "the goals are related to financial parameters."⁷⁵ The recommended decision correctly points out that performance indicators that address goals for safety, environmental protection, and customer service cannot readily be measured by dollar savings; others might further performance requirements for reliability and customer service that benefit ratepayers. Some of these types of performance measures might provide the kind of difficult to identify or quantify savings intended to be captured by the productivity imputation. We do not see that it would be categorically unjust or unreasonable for ratepayers to bear the costs of an incentive plan limited to such factors and not including financial parameters.⁷⁶

As noted earlier, the Company has withdrawn its variable pay plan request now and the Company's and other parties' exceptions are therefore moot.

⁷⁵ Case 90-G-0734 et al., supra, p. 8.

⁷⁶ We express no opinion on the acceptability of the various non-financial parameters in the Company's variable pay plan or how they might function in any revised plan the Company might propose. We do not think the record is sufficiently developed for that purpose. In addition, even if goals and targets in an incentive pay plan do not include financial factors, we remain concerned about the problem that funding would inure to the benefit of shareholders in the event performance falls short. On the other hand, providing funding subject to downward-only reconciliation could lead management to be less than rigorous in evaluating performance and making variable pay awards. To be acceptable, a variable pay plan would have to solve this dilemma. Finally, an acceptable plan would have to be shown not to provide excessive overall compensation and benefits compared to the overall compensation and benefits packages of similarly situated companies.

F. Other Incentive Compensation (Non-Officer and Officer Long-Term Compensation)

The Company provides long-term incentive compensation for officers and non-officer managers in the form of performance-based restricted stock (PBRs) units and time-based restricted stock units. PBRs performance targets are based 50% on the variable pay plan parameters and 50% on the incremental value an equity investor receives by holding one share of common stock over a period of time. The judges found that, because 50% of the long-term incentive plan for officers and non-officer managers is infected by the same financial parameters as the variable pay plan and the other 50% rests exclusively on shareholder return, ratepayer funding of the long-term incentive plan is even more objectionable than in the case of the variable pay plan. The judges therefore recommended adopting DPS Staff's adjustment to disallow funding for the long-term incentive plan.

The Company takes exception for the same reasons it put forward concerning the incentive variable pay plan.⁷⁷ DPS Staff and NYECC oppose on the same grounds on which they opposed the Company's variable pay plan exception.⁷⁸

The issues for the long-term incentive plan are the same as for the variable pay plan except, as the recommended decision explains, that the long-term incentive plan is even more heavily based on financial parameters that benefit shareholders rather than ratepayers. For the reasons explained in section IV(E) above, we deny the Company's exception.

⁷⁷ The Company's BoE, pp. 20-21. It is not clear whether the Company's March 25, 2009, letter that, among other things, withdrew its request for funding its variable pay plan intended to include this long-term incentive compensation funding request. Thus, we consider its exception.

⁷⁸ DPS Staff's BoE, pp. 14-17; NYECC's BoE, pp. 2-4.

G. Directors' Compensation

The Company provides 1,500 shares annually to each director on its board as compensation for service. Shares must be held until the director no longer serves. The recommended decision endorsed a DPS Staff adjustment to disallow the associated annual cost of \$0.690 million. The judges found that the compensation mechanism clearly furthers the interests of shareholders and has no direct relationship to providing reliable, reasonably priced service, concluding that ratepayers thus should not fund the expense. They noted that the Company could readily compensate directors in some way other than shares of stock, particularly stock that must be held until they leave the board.

The Company takes exception.⁷⁹ It contends that the stock awards are a legitimate cost of doing business and achieving good corporate governance, necessary to attract and retain qualified directors, and part of a compensation package similar to those of comparable companies. It claims the awards are made for service, not tied to Company performance, and thus constitute compensation for service, not an incentive plan. DPS Staff and NYECC oppose on the same grounds on which they opposed the Company's variable pay plan exception.⁸⁰

The Company's argument that the stock awards are not tied to the Company's performance and merely compensation for service, rather than an incentive plan, is incorrect. Because the compensation is in the form of stock, it provides greater benefit to the director, all other things being equal, if the Company performs well financially, to the benefit of shareholders independent of any benefit to ratepayers. The Company provides no reason why it cannot compensate directors in some other form that is not aligned with the interests of

⁷⁹ The Company's BoE, pp. 21-22.

⁸⁰ DPS Staff's BOE, pp. 14-17; NYECC's BOE, pp. 2-4.

shareholders but will still be sufficient to attract and retain competent directors, if it wishes ratepayers to bear the cost. If it chooses to retain this form of compensation, then the shareholders with whose interests it is aligned should shoulder the cost. We therefore deny the Company's exception.

V. EXPENSES - OTHER O&M

A. Pensions/OPEBs Expense Level

The recommended decision included a total recommendation of \$145.2 million for pension and other post-employment benefits (OPEBs) expense. The recommendation included the Company's original filing request of \$112.2 million, plus \$2.8 million based on new collective bargaining agreements. In addition, the judges included a \$30.2 million placeholder reflecting only a partial update for one known change, pending receipt of a full update including known changes for all pertinent variables for 2008 in the Company's brief on exceptions. The recommended decision also reflected a three-year amortization of the then-projected \$19.28 million deferred pension/OPEBs expense for the Linking Period, amounting to \$6.43 million for the Rate Year.

In its brief on exceptions, the Company now forecasts a pension/OPEBs expense level of \$206.99 million.⁸¹ The Company states that the update is based on information from Buck Consultants using actual 2008 year-end data, including a reduction in the discount rate from 6% to 5.75% and actual return on assets of negative 28%, compared to the original assumption of positive 8.5%. The Company now calculates the deferred Linking Period pension/OPEBs expense as \$45.78 million, or \$15.26 million in the Rate Year, assuming three-year amortization.

⁸¹ The Company's BoE, pp. 22-23.

DPS Staff concurs with the Company's update except for one element.⁸² DPS Staff states that the Company's update is incomplete, in that it employs the Company's old 2008 labor capitalization rate of 35.5%, rather than the Company's new 38% rate for 2009. Completing the update by correcting for the labor capitalization rate results in a Rate Year pension/OPEBs expense level of \$199.8 million, DPS Staff states, a \$54.6 million increase over the level reflected in the recommended decision. DPS Staff also notes that the labor capitalization rate affects calculation of the Linking Period deferral. The correction lowers the deferral amount from the Company's projected \$45.78 million to \$44.38 million, increasing the Rate Year allowance from \$6.43 million to \$14.79 million. DPS Staff also suggests that, given the size of the increased deferral amount under a three-year amortization, the Commission should consider an amortization period of up to 10 years.

We will adopt the Company's update for pension/OPEBs expense in the Rate Year and the Linking Period deferral, as corrected and completed to include the Company's current labor capitalization rate. (In any event, we note that pension/OPEBs expense is subject to full true-up.) We prefer not to add another category of current expenses being deferred for the longer term, however, and will maintain the three-year amortization period for deferred pension/OPEBs expense.

B. Municipal Infrastructure Support Expense Level

The Company presented a \$74.4 million updated request for municipal infrastructure or "interference" support work needed in response to construction by New York City in lower Manhattan. DPS Staff proposed a \$17.8 million reduction, to \$56.6 million. The Company's forecast relied on use of the

⁸² DPS Staff's BOE, pp. 17-18.

City's average "commitment target" levels⁸³ published in January of 2003 through 2007 and average of actual subsequent expenditures to commitment target levels. DPS Staff's approach used the City's average actual annual expenditure levels for the same period, adjusted for general inflation. DPS Staff also proposed a one-way reconciliation mechanism under which the Company would defer for the benefit of ratepayers any actual cost savings the Company realizes compared to the forecast amount, but absorb any cost overruns. The Company urged a two-way true-up, preferably, or otherwise none at all.

The judges found that, except for an 18% shortfall in the City's most recent year, its January commitment projections have been quite close to actual expenditures. Based on the January 2008 City projection the Company forecast a large increase in Rate Year expense compared to historic growth rates and 2007 Test Year expense. The judges noted that even in normal circumstances, projecting municipal infrastructure interference costs is difficult, and there is no good evidence on the record whether the current economic downturn is likely to increase or decrease the City's expenditure level. Under DPS Staff's forecast and a downward-only reconciliation, if the Company's forecast proves correct it would have a \$20 million shortfall, with the possibility of future recovery if it filed a deferral petition. On the other hand, ratepayers would be out \$20 million, with no clear way to be made whole, if the Company's forecast and no reconciliation mechanism are adopted but DPS Staff's forecast is correct. The recommended decision also observes that, although the Company's actual municipal infrastructure support expenditures are driven largely by the

⁸³ The percentage of overall projected infrastructure expenditures in the City's total commitment plan expected to be engineered, bid, and awarded each June-July City fiscal year, given that not all projects in the plan will be undertaken.

level of construction carried out by New York City, the Company can influence the efficiency with which its work is carried out.

Taking these considerations into account, the judges recommended against adoption of DPS Staff's forecast method and adjustment, but in favor of its proposed one-way downward reconciliation method. They also suggested that if other updated forecasts are considered at the time of our decision, the City's January 2009 construction forecast might also reasonably be taken into account.

1. Positions of the Parties

DPS Staff excepts to the recommendation to use the Company's forecast.⁸⁴ It contends that, while the City's relevant actual infrastructure expenditures and the Company's actual interference expense grew less than 1% and 0.5%, respectively, from 2003 through 2007, the Company's Rate Year forecast is \$23.4 million, or 46%, higher than Test Year expense, which is unreasonable in light of the economic downturn. It points to a May 2008 press release from the Mayor saying the City would reduce its capital budget by 20% for the 2009-2012 period (Tr. 2512) and a post-record November 2008 City Council budget note setting forth significant capital commitment reductions for the same period in relevant categories. DPS Staff maintains the judges' observation that the economic downturn could increase or decrease the City's expenditures is unsupported by evidence and speculative. Additionally, DPS Staff says a report it recently received from the Company confirms its Rate Year interference forecast, by showing the Company's actual 2008 interference expense to be only \$0.6 million greater than DPS Staff's estimate using its own method, but more than \$10 million below the Company's internal estimate using the Company's method. DPS Staff concludes by stating

⁸⁴ DPS Staff's BoE, pp. 9-11.

that, should we adopt the Company's methodology, we should substitute the City's actual commitments in 2008 for the Company's forecast and, as the judges recommended, update the City's fiscal year 2009 forecasts using the City's January 2009 commitment plan.

The Company responds, underscoring the judges' findings about the difficulty of predicting interference costs even in better economic circumstances and the uncertainty over whether City infrastructure expenditures will increase or decrease in the current economy.⁸⁵ It counters DPS Staff's reference to the Mayor's May 2008 press releases and the post-record City Council budget note by referring to a recent presentation by the mayor saying no reductions in the City's capital commitment plan for 2009 are currently planned. The Company objects to DPS Staff's use of a five-year historic average plus general inflation when materially lower than a forecast based on the "best available information," because there is no basis for assuming we would adhere to that approach in the future if faced with information suggesting the result would overestimate interference costs. It argues we rejected such a purely historical approach in our 2008 Rate Order, in the face of DPS Staff and Company support of a higher estimate based upon their knowledge and review of City plans. The Company contends consistent application of DPS Staff's method here with downward-only reconciliation will result in under-collection of interference costs over time.

The Company concludes by offering a revision of its own forecast using the City's actual 2008 commitments, as DPS Staff suggested on exceptions, and the City's January 2009 commitment plan, as the judges and DPS Staff suggested. It states that the revised forecast drops to \$72.5 million from the

⁸⁵ The Company's BOE, pp. 8-10.

Company's prior forecast of \$74.4 million. The Company objects to reflecting the update in its cost of electric delivery service, however, for reasons it has generally explained for updates at this stage of the proceeding.

For its own part, the Company excepts to the judges' recommendation of downward-only true-up.⁸⁶ It cites the judges' acknowledgement of the difficulty of forecasting interference costs, especially in the current economy (alluding to press reports about possible stimulation through increased governmental spending on infrastructure), its considerable lack of control over the costs, and inconsistency with the judges' recommendation of bilateral reconciliation for property taxes. The Company also says the record contains no evidence to support the suggestion that a two-way reconciliation reduces or eliminates its incentive to control interference costs, but shows its aggressive efforts to do so. It also contends it has had bilateral mechanisms in place for interference costs in prior rate plans, with no allegations it has failed to seek to minimize those costs.

DPS Staff opposes the Company's exception.⁸⁷ Its only argument, however, relates solely to its own forecast method. DPS Staff says that, because it did not adjust its forecast further to account for the impact of the economic downturn (criticizing the Company's reference to unspecified press reports), its forecast is conservative (presumably, on the high side) and thus one-way true-up is warranted. Presumably, its position implies that, because the judges' recommendation is more conservatively high, it warrants downward-only reconciliation even more.

⁸⁶ The Company's BoE, pp. 23-24.

⁸⁷ DPS Staff's BOE, p. 18.

2. Discussion

Given the current economic downturn, we conclude it is unlikely that the Company will incur municipal infrastructure support expense approximately \$17.8 million higher than the inflation-adjusted historic average of \$56.6 million. The record also shows that the Company's approach in a recent year yielded a forecast \$18 million higher than the actual O&M expense. Application of DPS Staff's approach also yields better results based on a comparison with 2008 actuals. The Company's forecast also rests on more variables than DPS Staff's, increasing the chances of error.

In reaching this conclusion, we give no weight to competing post-record releases from the Mayor and City Council about the magnitude of New York City's construction program in the coming year. We also have no way of knowing today how, if at all, the City's actual construction in the coming year will be affected by the economic stimulus package, which might provide significant support for municipal and other government infrastructure spending.

The judges recommended the Company's forecast in light of their separate recommendation to apply a one-way, downward-only reconciliation to municipal infrastructure O&M costs. Under that mechanism, revenues allowed for projected municipal infrastructure O&M that proves greater than the actual would be held for the future benefit of ratepayers. Given the extent to which the Company's municipal infrastructure operation and maintenance expenses are driven primarily by the City's plans and only secondarily by the efficiency with which the Company completes the necessary work, we decline to adopt a one-way, downward-only reconciliation for this expense category.

C. T&D Non-Labor Program Expense

1. Five-Year Underground Inspection Program

The judges recommended against a DPS Staff adjustment intended to disallow \$16.7 million for an increase of 35,000 in the estimated number of underground structures still requiring inspection. They found a lack of evidentiary support for DPS Staff's contention that the additional inspections were an artifact of double counting from errors in reconciling databases and under-scheduling unique inspections and determined that the Company had provided sufficient evidence in support of its updated estimate. The recommended decision did not address a DPS Staff claim in its initial brief speculating that the Company's management of the inspection program might be inadequate.

The judges also recommended against the Company's request for an additional \$6.6 million for repairs of defects found during underground inspections. The Company proposed that level of funding based on a DPS Staff proposal in Case 04-M-0159 for the times to be allowed for completing such repairs. Our order in that case issued shortly after the parties filed trial briefs in this proceeding.⁸⁸ The judges noted that the Safety Standards Order extended the times for two of three categories of repairs, increasing the time for Level II priority repairs by 100% and for Level III priority repairs by 50% over the times DPS Staff had proposed and the Company assumed in making its estimate.⁸⁹ Because the judges could not evaluate the extent to which the Company would need any additional funding

⁸⁸ Case 04-M-0159 et al., Safety of Electric Transmission and Distribution Systems, Order Adopting Changes to Electric Safety Standards (issued December 15, 2008)(Safety Standards Order).

⁸⁹ Id., pp. 15-18.

for repairs, given the longer allowed repair times, they recommended against the Company's update request.

a. Positions of the Parties

DPS Staff takes exception to the recommendation against its proposed \$16.7 million adjustment for additional inspections. On exception, DPS Staff says the additional funding should be denied because (a) the Company poorly managed the inspection program, by not planning properly, waiting too long to begin the program, and not addressing an issue with its inspection tracking database; and (b) additional funding was allowed in the Company's last electric rate case to hire additional mechanics to address remaining inspections, but the Company used contractors instead and only to perform inspections, not make repairs.⁹⁰ The Company responds that DPS Staff merely rehashes arguments it made to the judges that were rejected, provides no explanation of how the recommended decision's analysis errs, and adds irrelevant argument about contractors versus employees.⁹¹

For its part, the Company excepts to the judges' recommendation against the \$6.6 million for repairs discovered during inspections.⁹² It maintains that because the Safety Standards Order only extends deadlines for completing repairs, but does not reduce the work to be performed, their recommendation provides no funding for mandated work. The Company acknowledges that the extension will reduce its Rate Year costs, but not to zero. It proposes allowance of \$3 million as a reasonable proxy, reducing its original estimate by more than half. It maintains the changes flowing from the Safety Standards Order constitute changed circumstances it could

⁹⁰ DPS Staff's BoE, pp. 20-21.

⁹¹ The Company's BOE, pp. 27-28.

⁹² The Company's BoE, pp. 25-27.

not have anticipated and that some reasonable allowance for repairs is warranted.

DPS Staff opposes the Company's proposal.⁹³ It reviews the three levels of repairs and their deadlines: Level I, within one week; Level II within one year; and Level III, within three years. DPS Staff also states the Test Year includes funding for repairs of the Level I type. It contends that the Company has provided no evidence in support of its \$3 million proposal.

b. Discussion

To begin, we note that DPS Staff's argument about Company mismanagement of the underground inspection program fails to address any of the reasons set forth in the recommended decision for accepting the Company's estimate of the number of additional inspections needed, on which the funding estimate is based. In addition, its argument about the Company hiring contractors instead of employees to carry out underground inspections is irrelevant to the issue of the Company's estimate of the number of additional inspections needed, on which the funding estimate is based. Thus, we see no basis for granting DPS Staff's exception.

The Company has now provided updated information on the number of inspections it will have to conduct during the Rate Year, however. Its latest annual report on stray voltage and facility inspections indicates that, rather than 94,000 inspections, it will conduct about 75,900 inspections during the Rate Year as it completes its initial five-year inspection cycle

⁹³ DPS Staff's BOE, p. 19.

and embarks on the next inspection round.⁹⁴ We will therefore use that number as the basis for determining a reasonable allowance for Rate Year inspections.

The record does not include a total cost figure for the 75,900 inspections that can now be expected to be carried out in the Rate Year. The Company's original filing estimated a cost of \$23.8 million to perform 59,000 inspections, yielding an average cost of \$403 per inspection. Its update estimated \$40.5 million to conduct 94,000 inspections, for an average of \$431 per inspection. These are only mathematically derived unit costs, however. The record does not include any direct information on an appropriate overall or unit cost for 75,900 inspections. Both the \$403/inspection figure and the \$431/inspection figure are derived in the same manner from total cost estimates supported by the Company. The Company urges the use of the higher figure because of changes to the scope of work associated with inspections that have increased the efforts associated, on average, with each inspection.

The Company is also requesting funding for repairs of conditions discovered during underground inspections, however, despite the Safety Standards Order's extensions of deadlines for Level II and Level III repairs. We understand the judges' reluctance to recommend funding for repairs, since they lacked specific information on an alternative to the Company's \$6.6 million pre-Safety Standards Order request. On the other hand,

⁹⁴ Consolidated Edison Company of New York, Inc., 2008 Stray Voltage Detection and Electric Facility Inspections Report (filed January 15, 2009), p. 47, Table 12. The Company has 82,400 inspections remaining to complete in its first five-year round of inspections, which runs through the end of calendar 2009. It will then begin its second five-year round, and beginning in calendar 2010 will have to inspect an average of 56,500 per year of its 282,500 underground facilities. For the Rate Year, the number of inspections to be performed therefore is: $82,400(.75) + 56,500(.25) = \sim 75,900$.

the Company made a good faith effort to estimate the costs of required repairs during the hearings. It was disadvantaged by the fact that our decision in the Safety Standards Order issued only after the hearings ended and trial briefs were submitted in this proceeding.

Given the extended three-year deadline for Level III repairs, there might be no need for any Level III work in the Rate Year. The Company can reasonably be expected to have some additional costs for Level II repairs, although they are likely to be significantly less than it had estimated for the Rate Year.⁹⁵ On the other hand, there also appears to be duplication in the Company's estimates for inspections and repairs, since the work scope the Company cites for the changes to its specifications for inspections, which entail additional repair work, overlaps the scope covered by its separate estimate for costs of repairs (Ex.324, pp. 10-11). To minimize the chance of duplication while recognizing the potential for additional repair costs, we find it reasonable to use the \$403/inspection unit cost derived from the Company's original filing, applied to the 75,900 inspections now projected for the Rate Year, together with the \$3 million it now requests for repairs of defects detected during inspections. The total allowance will therefore be \$33.6 million.

One additional consideration remains. The 75,900 inspections in the Rate Year are greater than the 56,500 annual inspections the Company will have to carry out on a continuing basis in the future. To moderate the effect of those additional one-time costs, we are requiring that the costs of the incremental inspections for the Rate Year (\$7.8 million for

⁹⁵ Level II defects detected in the current rate year would have to be repaired in the Rate Year. Those detected in the early month of Rate Year might well be the subject of repair work in the Rate Year, given the one-year deadline under the Safety Standards Order.

19,400 inspections) be collected through a two-year amortization.⁹⁶ Accordingly, the total Rate Year allowance for five-year underground inspections and repairs is \$29.7 million.

2. Structural Integrity/Station Betterment

DPS Staff proposed to disallow \$0.765 million of the Company's overall request for funding for structural integrity/station betterment work at substations. The judges disagreed, finding that DPS Staff did not contest the need for certain work for which cost estimates were not available or the Company's contentions that facility maintenance and repair work is continually being identified and more projects will be identified during the Rate Year. Instead, the judges recommended a disallowance of \$375,000 on the ground that the Company should have been able to do better at estimating costs of painting and concrete work at a number of substations.

DPS Staff excepts, maintaining that the Statement of Policy on Test Periods requires cost projections that are readily verifiable and that there are no cost estimates from the Company or identified known changes to support the \$765,000 of requested funding that it challenged.⁹⁷ The Company argues in response that it identified the need for the projects, that DPS Staff did not contest the need for the work or that the work is of a continually emerging nature, that detailed estimates for individual substation projects were still being developed, and that its estimates represented approximate costs based on historical expenditures for similar work scopes (Ex. 169 (redacted), pp. 867-70).⁹⁸

⁹⁶ In accordance with our discussion of treatment for deferred overhaul and Local Law II expenditures, Section IX(E) *infra*, we authorize carrying charges for these expenses based on the other customer capital rate in the Rate Year and the Company's overall rate of return subsequently.

⁹⁷ DPS Staff's BoE, pp. 21-22.

⁹⁸ The Company's BOE, pp. 28-29.

We agree with the judges that the Company could, and should, have done a better job of estimating the costs of these substation maintenance and repair projects. The Company's contention that its estimates represented approximate costs based on historical expenditures for similar work scopes and that such substation maintenance work is continually being identified implies that it has the experiential base, and should have the resulting cost information, to have provided more detailed specific support for the 29 substation projects in question for which it provided no specific support in response to DPS Staff discovery. Since it did not provide that support, we do not adopt the judges' recommendation, but disallow the recommended \$375,000.

3. Mobile Stray Voltage Testing

DPS Staff proposed a \$414,000 disallowance to the Company's request for mobile stray voltage testing. The judges recommended against the adjustment, finding that DPS Staff's estimated Rate Year cost failed to account for monthly variations in the number of vehicles required for each scan. The judges found the Company's estimate more reasonable because it is based upon competitively-bid costs for scans to be carried out over the full year 2008. The 2008 bid costs were significantly lower than they would have been if based upon Test Year costs, because competitive bidding reduced per-scan costs. DPS Staff excepts.⁹⁹ It claims that its estimate does take into account month-to-month variation in number of vehicles required for each scan because it was extrapolated from actual expenditures for the first five months of 2008. The Company did not respond.

DPS Staff's estimate is based on less reliable data than the Company's. DPS Staff provides no reasoned explanation

⁹⁹ DPS Staff's BoE, pp. 22-23.

of why an estimate extrapolated from only the first five months of the year can reliably be assumed to capture variation in number of vehicles required per scan for 12 months of the year. We agree with the recommended decision that, because the Company's forecast is based on competitive bidding for the scans to be carried out over the full year, it does reliably capture variation in number of vehicles required per-scan over the course of the entire year. DPS Staff's exception is denied.

4. Annual Stray Voltage Testing

DPS Staff proposed to disallow just over \$1 million of the Company's \$8.9 million request for non-labor O&M costs of annual stray voltage testing. The judges recommended that the adjustment be rejected. They explained that the Company had presented reasoned arguments against DPS Staff's proposal, which DPS Staff had not addressed in brief.

DPS Staff takes exception, claiming that its adjustment is based on historic spending levels, historic hiring rates, or both and that it did brief those issues generally.¹⁰⁰ The Company opposes the exception, noting that the recommended decision summarized the Company's criticisms of DPS Staff's adjustment, which DPS Staff had failed to address.¹⁰¹

DPS Staff's adjustment was not based upon historical hiring practices at all, but only on its historic costs (non-labor) adjustment, which it says is based upon analysis of individual budget items. DPS Staff presented no specific analysis of annual stray voltage testing, simply a bare number representing the amount of its adjustment. In fact, DPS Staff failed to address in brief at the trial level the Company's reasons for objecting to the adjustment. It still presents no

¹⁰⁰ DPS Staff's BoE, p. 23.

¹⁰¹ The Company's BoE, pp. 29-30.

reasoned argument responding to the Company's criticism of the adjustment.

Our own review of the record indicates that the amount the Company has requested appears excessive. The Company spent \$5.297 million in 2006 and \$5.520 million in 2007 on annual stray voltage testing. It spent \$1.6 million through the first four months of 2008, which, if annualized and escalated by a generous \$2 million for more activity during the summer, would result in about \$6.8 million for the full year. A trend line analysis based on these figures produces a reasonable allowance of \$7.5 million, or a downward adjustment of \$1.4 million from the level reflected in the recommended decision. Although this allowance does not explicitly account for a potential increase in contractor costs, we note the Company asserts that the additional contractor resources will also assist it in performing repairs required by the Safety Standards Order,¹⁰² for which we have already provided additional funding in the context of five-year underground inspections. Our allowance here provides an additional \$0.7 million over the annualized and escalated amount for 2008, which we conclude is reasonable.

5. Maintenance Associated with Capital Work

DPS Staff proposed a \$3 million adjustment to maintenance associated with capital work (Ex. 173, p. 5). Noting the Company's contention that DPS Staff gave no reason for the adjustment and that DPS Staff did not address the issue in brief, the judges recommended that the Company's full request be approved. DPS Staff excepts, claiming that its adjustment was based upon historic spending levels, historic hiring rates, or both and that it briefed those issues generically.¹⁰³ The Company objects that DPS Staff did not explain the basis for its

¹⁰² The Company's Initial Brief, p. 149.

¹⁰³ DPS Staff's BoE, p. 23.

adjustment in testimony or in brief and even admits in its brief on exceptions that it did not address this adjustment or the particular basis for it specifically.¹⁰⁴

The judges' recommendation is understandable in light of DPS Staff's failure to address this issue and the Company's arguments specifically in its trial briefs. DPS Staff still has not identified even in its brief on exceptions the specific basis for its adjustment or addressed the Company's reasons for opposition set forth in its initial trial brief. Nonetheless, although not cited anywhere by DPS Staff, further review of the record indicates there is testimony identifying this adjustment as part of DPS Staff's historic hiring practices adjustment (\$2.920 million for labor and \$0.104 million for associated material and supplies)(Tr. 3012-13). Thus, as in the case of the emergency management positions discussed in IV(A)(2)(f) above, to maintain consistency we will apply the judges' recommended historic hiring practices adjustment and disallow 55% of the requested funding (\$2.772 million -- \$2.677 million for labor and \$0.095 million for associated materials and supplies).

D. Shared Services Non-Labor Program Expenses

1. West 28th Street

The recommended decision disagrees with a DPS Staff proposal to disallow \$6.828 million the Company requested for relocation of its West 28th Street Work-Out Services Center to accommodate New Jersey Transit's construction of two new rail tunnels. The judges found the best evidence on the record shows the project likely to proceed in 2009, driving the Company's associated costs. The judges recommended the Company's requested funding, subject to deferral of all reimbursements from New Jersey Transit for the benefit of ratepayers.

¹⁰⁴ The Company's BOE, p. 30.

DPS Staff takes exception on the grounds that there is insufficient evidence the project will progress or affect the Company as projected; and that, in any event, the recommendation does not provide adequate protection for ratepayers.¹⁰⁵ It argues that the project could be delayed or the Company might not have to relocate all of its facility. DPS Staff notes that the Company itself suggested the costs associated with the project be reflected in its cost of electric delivery service subject to full reconciliation. Finally, DPS Staff maintains that we should require the Company to pursue cost reimbursement from New Jersey Transit aggressively.

The Company opposes DPS Staff's argument that the project might not proceed during the Rate Year, citing a record of decision issued by the Federal Transit Administration approving it.¹⁰⁶ The Company agrees to full reconciliation of the total actual moving and relocation costs to the amount allowed in rates, net of reimbursements, as long as reconciliation occurs after all costs have been paid and all reimbursements have been received, which it says might result in carryover of costs and reimbursements beyond the Rate Year. The Company cites the recommended decision's finding of no evidence that it would not pursue reimbursement aggressively and insists that it has done that so far.

Notwithstanding the judges' recommendation and the contentions and counterpoints of the parties, we note that nothing in the Company's arguments suggests New Jersey Transit should not reimburse the Company for the full costs it might incur for relocation of the West 28th Street facilities. Consequently, it is reasonable for the Company to seek reimbursement of its costs from New Jersey Transit in the first instance, rather than their imposition on ratepayers. The

¹⁰⁵ DPS Staff's BoE, pp. 23-24.

¹⁰⁶ The Company's BoE, pp. 31-32.

Company may defer for future recovery those costs that it can show it reasonably incurred to accommodate the project and used its best efforts to have reimbursed, without success. This approach also will obviate DPS Staff concerns about whether relocation will occur during the Rate Year or whether the Company will have adequate incentive to seek cost reimbursement from New Jersey Transit.

2. Central Field Services - Vehicle Fuel

The judges rejected all of the parties' proposed vehicle fuel cost estimates as unreliable, because of the extreme drop in petroleum and vehicle fuel prices over the latter part of 2008. They recommended determination of vehicle fuel cost for the Rate Year on the basis of the latest available Energy Information Administration (EIA) Short-Term Energy Outlook (STEO) monthly report projections of annual average regional retail vehicle fuel prices for 2009, adjusted downward by \$0.30 per gallon to reflect the Company's bulk fuel purchase savings.

On exceptions, the Company states that it does not object to use of the latest available STEO monthly projections, adjusted as recommended to reflect its bulk fuel purchase savings, but insists that regional prices should be used and objects to the fact that the placeholder the judges included in calculating the recommended decision's cost of electric delivery service was based on national rather than regional price projections.¹⁰⁷ DPS Staff and NYECC do not except to the recommended decision, but oppose the use of regional rather than national prices.¹⁰⁸ DPS Staff claims the Company provides no references to the retail prices it wishes to use and that regional data were available before and throughout the

¹⁰⁷ The Company's BoE, pp. 27-28.

¹⁰⁸ DPS Staff's BOE, pp. 19-20; NYECC's BOE, pp. 4-6.

proceeding, so that substituting regional data now would not be for a "known change."

DPS Staff's and NYECC's objection to the use of regional fuel price projections is not well taken. The Company made its argument for use of regional prices in its reply trial brief and in the recommended decision the judges endorsed using regional prices from the EIA STEO. Neither DPS Staff nor NYECC took exception to that recommendation and their opposition amounts to interposing an exception tardily. In any event, the East Coast regional gasoline price projection in EIA's STEO report for March 10, 2009, is two cents lower than its national average price projection; and no regional price projection for diesel fuel appears to be available in that report. The STEO report projects an average 2009 retail price for regular grade gasoline, including taxes, in the East Coast region of \$1.94 per gallon.¹⁰⁹ It projects a national average 2009 retail price for on-highway diesel fuel, including taxes, of \$2.19 per gallon.¹¹⁰ Adjusting by \$0.30 per gallon yields prices to the Company for its discounted bulk fuel purchases of \$1.64 per gallon and \$1.89 per gallon, respectively; and a total vehicle fuel allowance of \$2.355 million.¹¹¹ We will include this amount, which is \$654,000 less than the \$3.0 million placeholder in the recommended decision, in the Company's cost of electric delivery service.

¹⁰⁹ U.S. Energy Information Administration Short-Term Energy Outlook Report, March 10, 2009, Table 4c - U. S. Regional Motor Gasoline Prices and Inventories (<http://www.eia.doe.gov/emeu/steo/pub/mar09.pdf>).

¹¹⁰ Ibid., Table 2 - U.S. Energy Nominal Prices.

¹¹¹ The Company's electric operations allowance is determined using the same formula set forth in n. 248, p. 151, of the recommended decision: [(1,798,639 gal. diesel x \$1.89/gal.) + (1,806,636 gal. gasoline x \$1.64)] x 37.0%. (Since these volume figures relate to all of the Company's operations, the 37% factor adjusts for the share applicable to electric operations.)

E. Informational & Institutional Advertising

Long-standing Commission policy on informational and institutional advertising limits expenditures for that purpose to the range of 0.04% to 0.10% of a utility's operating revenues.¹¹² The Company sought an allowance of \$17.573 million for its informational and institutional advertising program, amounting to 0.211% of total electric operating revenues under its September 2008 updated rate request. It cited language in the 2008 Rate Order where we indicated that, if it thought the standard Policy Statement allowance would be inadequate, it could submit program plans for review with its request for additional funding.¹¹³ DPS Staff proposed to disallow all but \$6.7 million. The judges recommended an allowance of \$12.931 million, providing for all of the Company's request but \$4.642 million targeted for informing customers and the public about its work on infrastructure development.

The judges analyzed the Company's contentions about higher costs and greater difficulty of reaching target audiences in its service territory and found that the record did not provide sufficient evidence to determine whether the Company's per capita costs for reaching its audiences are incrementally higher than in other parts of the State or whether the Advertising Policy Statement is in or out of date any more for the Company than for other utilities in New York. With respect to the \$8.8 million the Company budgeted for energy conservation tips they determined that energy conservation is an important Commission-supported message and did not accept DPS Staff's position that this part of the budget costs too much. They

¹¹² 17 NYPSC 1R, Statement of Policy on Advertising and Promotional Activities of Public Utilities (issued February 25, 1977) (Advertising Policy Statement), pp. 11R-15R.

¹¹³ 2008 Rate Order, pp. 47-48.

noted that the EEPS case¹¹⁴ is considering the extent to which funds should be allowed for program-specific energy efficiency marketing, and that the allowance here for energy conservation tips should be reduced if the energy conservation tips funding requested here duplicates funding expected there. They found that the emergency preparedness and supplier diversity portions of the Company's proposed budget (\$1.839 million each) are consistent with good public policy, no party presented any specific reason to reduce the proposed level of funding, and DPS Staff had suggested emergency preparedness deserved even more. They rejected all proposed funding for information to tell customers and the public how rates underwrite improvements in infrastructure, as a subject customers are not likely to wish to pay nearly \$5 million a year to hear about in average times, which constitutes a luxury in an economic downturn.

1. Positions of the Parties

The Company takes exception to the elimination of funding proposed for disseminating information on how it is investing rate revenues in infrastructure improvement.¹¹⁵ It maintains that the Advertising Policy Statement recognizes this category of advertising as in the public interest and a legitimate business expense recoverable in rates, which should not have been dismissed merely because the judges thought it unnecessary. It adds that infrastructure advertising also provides additional opportunity to provide its contact information to customers and the public. With respect to energy conservation tips, the Company says that the advertising proposed here addresses energy efficiency generally and does not include specific marketing for specific programs. The latter

¹¹⁴ Case 07-M-0548, Energy Efficiency Portfolio Standard (EEPS).

¹¹⁵ The Company's BoE, pp. 28-29.

would be covered only in the EEPS case and coordinated with its general energy conservation advertising to avoid overlap.

DPS Staff takes exception on the grounds that the recommended decision errs by supporting funding in excess of the 0.04% to 0.10% of operating revenues range allowed under the Advertising Policy Statement and by engaging in programmatic review of the four proposed advertising categories, which it states the Advertising Policy Statement was intended to end.¹¹⁶ DPS Staff maintains that, although it did not make specific recommendations on relative priorities of the several advertising categories, it did offer guidance, including an increase to emergency preparedness and the view that energy conservation advertising would better support the State's goals if focused on specific programs, implying funding should be reduced here and concentrated on EEPS case programs.

Although DPS Staff also agrees with the Company that infrastructure advertising is specifically allowed by the Advertising Policy Statement, it opposes the Company's proposal to restore all funding for infrastructure advertising.¹¹⁷ Instead, it asserts its proposed level of \$6.7 million is sufficient for all of the Company's informational advertising needs and consistent with its historic spending levels, including infrastructure advertising. DPS Staff notes that the 0.04% to 0.10% of operating revenues range in the Advertising Policy Statement would result in a budget range of \$3 million to \$7.5 million for the Company, but that under that Statement the allowed percentage within the range should be inversely proportional to the size of the utility.

The Company opposes DPS Staff's exception.¹¹⁸ It contends the recommended decision accepted the Company's

¹¹⁶ DPS Staff's BoE, pp. 25-27.

¹¹⁷ DPS Staff's B0E, pp. 20-21.

¹¹⁸ The Company's B0E, pp. 33-35.

baseline premise that it was responding to our indication in its last electric rate case that it was free to make its case for a higher allowance than would be permitted under the Advertising Policy Statement and that it has done so with specific and detailed programs to address areas of major concern to its customers, the public, and this Commission. The Company asserts that the recommended decision found DPS Staff's proposed adjustment would require cuts to its energy conservation, emergency preparedness, and supplier diversity advertising programs with no explanation of why such reductions would be reasonable. The Company argues that DPS Staff's criticism of the level of proposed spending on energy conservation tips is inconsistent with the Policy Statement's intent to avoid scrutiny of particular advertising and, in any event, that Statement expressly recognizes energy conservation advertising as proper subject matter. Finally, the Company says the recommended decision did distinguish between its general conservation advertising allowable in this case and its energy efficiency program-specific advertising to be addressed in the EEPS case. The Company reiterates that its programs will complement each other, not overlap.

2. Discussion

The Company's and DPS Staff's insistence on the Advertising Policy Statement intent to do away with program or advertisement-specific review of informational advertising would be correct if the level of spending the Company proposed fell within the spending limits set forth in that Policy Statement. The Policy Statement set a limit on informational advertising expenditures in order to avoid specific review of individual advertising areas and particular ads. But here the Company proposes spending at a level more than 100% greater than permissible under the Policy Statement, based upon specific proposed justifications for specific programs. Nothing in the

Policy Statement indicates any intent to preclude program-specific review of informational advertising proposals that fall outside the scope of its spending limits. Thus, the judges' review of the merits of the individual program categories was both permissible and necessary, under the belief that we had previously recognized the possibility of allowing funding beyond the range allowed under the Policy Statement.

The Company's and DPS Staff's argument that the Advertising Policy Statement specifically recognizes spending on infrastructure advertising as a legitimate expense is beside the point. The Policy Statement recognizes a number of different types of informational advertising as legitimate business expenses, but it nonetheless imposes limits on spending on them that can be recovered from ratepayers. Here, the Company proposes to depart from the limitations of the Policy Statement. If it seeks approval of an expense allowance far in excess of that permitted under the Policy Statement, then it is subject to review and determination of how much of which of the proposed categories of expenditure should be allowed as reasonable.

In the 2008 Rate Order, however, we reiterated our concern over the subjective nature of evaluating informational and institutional advertising and noted the continuing merit of the Advertising Policy Statement.¹¹⁹ The arguments of the parties over the Company's proposals in this case, together with the analysis in the recommended decision, serve to underscore the quagmire that having to engage in such a subjective evaluation creates. It was precisely to avoid these kinds of subjective disputes, and the commitment of resources necessary to review and evaluate them, that this Commission originally

¹¹⁹ We did not intend to suggest there that we would be open to departure from the range established in the Policy Statement, but only the 0.06% (inadvertently stated as 0.6%) standard allowance for a company of Consolidated Edison's size.

adopted the Policy Statement. Rather than see future proceedings flounder in similar morasses, we renew our commitment to the Advertising Policy Statement for the same reasons this Commission originally adopted it. Accordingly, rather than grant the Company's exception or adopt the judges' recommendation, and in light of the Company's overall plans for informational advertising as presented in this case, we will increase the allowance within the Policy Statement range to 0.08% of the Company's electric operating revenues.

F. Employee Welfare Programs

The Company requested \$517,000 to fund a work - home wellness program for its employees. The judges adopted a DPS Staff proposed adjustment to eliminate that funding. They noted that the requested funding increase applies not only to new program elements, but also to expansion of existing elements to serve more employees. Thus, they found that the Company should have been able, but had not even tried, to project offsetting savings in the Rate Year.

The Company excepts.¹²⁰ It maintains there is no basis for assuming savings will fully offset the costs of the work - home wellness program. The Company says DPS Staff did not attempt to quantify savings from the program or provide any evidence such a projection could be made. It suggests that the 1% productivity imputation the judges recommended for capturing unquantifiable savings should be considered to capture unquantifiable savings from this program. It also argues that the recommended decision does not explain why a reduced health insurance projection in its update for this proceeding should not be attributed in part to the program. The Company maintains customers will benefit in intangible ways from the program and

¹²⁰ The Company's BoE, pp. 29-30.

should not be able to receive its full benefits without contributing to its costs.

DPS Staff opposes the exception.¹²¹ DPS Staff contends that literature the Company introduced shows that there should be health care cost savings in the Rate Year. It argues that the Company has had a number of employee welfare programs in place that, as DPS Staff maintains, should have produced savings such as the health insurance reductions reflected in the Company's update filing, demonstrating that the expanded work-home wellness program should produce off-setting savings that the Company had the opportunity to project but did not. In addition, DPS Staff suggests that discretionary programs like this one should be rejected if savings do not fully offset their costs, because of the current economic climate and the impact of a rate increase on customers.

We find unpersuasive the Company's arguments that cost savings might not fully offset increased work-home welfare program costs and that DPS Staff failed to quantify potential savings or demonstrate that savings could be quantified. The recommended decision did not find that cost savings would fully offset increased costs. It did find that the requested increase applies to expansion of existing program elements to serve more employees. Thus, based on experience, the Company should have been able to project some offsetting savings in the Rate Year. It should have presented evidence of the extent of cost savings that could reasonably be expected in the Rate Year or a plausible explanation of why such savings are not quantifiable. It did not. Moreover, since the Company has not shown why savings from the expansion of the program are not quantifiable, its argument that the unquantifiable savings from the program are captured by the productivity imputation is irrelevant.

¹²¹ DPS Staff's BOE, pp.21-22.

Nor did the judges have the obligation to show why health insurance savings in the Company's update should not be attributed in part to the existing work-home wellness program. The Company had the obligation to show that the program did contribute in part to those health insurance savings, if it believed that to be true. In any event, it is not clear how those particular past savings could reasonably be attributed even in part to the expansion of the program for which the Company requests funding in the Rate Year.

Finally, we note that the Company is not required to expand the work-home wellness program and bear the increased costs without a contribution from ratepayers, if it believes ratepayers will enjoy benefits from program expansion without contributing to its costs. Otherwise, in these challenging economic times, the Company should be looking for additional ways to economize, rather than ways to expand discretionary programs. We deny the Company's exception.

G. Insurance

1. Directors and Officers Liability Insurance

The Company sought \$4.007 million for its electric operations' share of \$300 million in directors and officers liability (D&O) insurance coverage. The recommended decision found that the Company's level of coverage was excessive in relation to that of other comparable companies and recommended a coverage limit of \$200 million as reasonable, but conservative. The judges rejected a DPS Staff proposal to allow only 10% of the allocable premium costs, to cover legal defense, as focused too narrowly on where money from a successful claim would flow and on the possibility of covered acts close to illegal or fraudulent that ratepayers should not have to pay through premiums funded in rates. Instead, the judges recommended an allowance of 90% of the premium cost for \$200 million of

coverage, which they calculated as \$2.404 million (with a related adjustment to rate base for prepaid insurance).

a. Positions of the Parties

The Company excepts for three reasons.¹²² First, it challenges the recommended decision's finding that \$200 million in coverage is sufficient. The Company cites advice from insurance brokers that \$300 million is prudent; refers to a peer group study showing its coverage level is bracketed by two other utilities whose capitalizations bracket its own; lists factors distinguishing it from other companies, included in broader surveys, that face different risks; and points out survey results showing utilities to be the business class most susceptible to D&O claims (Tr. 1820-21, 1824-25; Ex. 260, p. 53; and Ex. 294).

Second, the Company takes issue with the limitation of recovery to only 90% of premium costs allocable to electric operations. The Company maintains the requirement that it bear 10% of the cost is unsupported by any explanation and arbitrary. It contends that the Company showed D&O coverage to be a necessary and legitimate business expense; that the recommended decision recognized the nearly universal purchase of D&O coverage by all different kinds of companies and the benefit it provides to ratepayers in facilitating attraction of competent directors and officers. The Company states that the record contains no support for allocating responsibility for the D&O premium between ratepayers and investors and notes that the judges rejected DPS Staff's attempt to do so on the basis of financial benefit or the argument that coverage might extend to acts close to fraudulent or illegal (Tr. 1766, 1810-17).

Finally, the Company contends that the recommended decision incorrectly calculated the amount of its adjustment to

¹²² The Company's BoE, pp. 31-34.

the premium allowance for the lower coverage level of \$200 million. It explains that premiums are not determined on a proportional basis, as the recommended decision presumed, but on a declining layer basis as coverage levels increase (Ex. 396-A, response to CPB 20). Thus, the Company calculates the allowance for the judge's recommendation of funding for 90% of the portion of the premium for \$200 million in coverage allocable to its electric department should be \$2.9 million. If we accept rate recovery of the full allocable cost for the electric department of the premium for \$200 million, the Company calculates the allowance should be \$3.2 million.

NYECC opposes the Company's exception on proper coverage level and contends the recommended decision's result is supported by the record. It argues that a 2007 study by Towers Perrin of public companies with assets or market capitalization greater than \$10 billion shows, as the judges found, the Company is over-insured by \$131 million to \$154 million in carrying \$300 million in coverage (Ex. 260, pp. 14-15). NYECC also points to the Company's own peer group surveys of utility D&O coverage as showing the Company has been over-insured by \$33 million to \$150 million over the period from 2004 through 2006, and that most of the Company's peer companies had coverage limits as a percentage of market capitalization significantly lower than the Company did (Ex. 396-B). NYECC contends that, although the Company listed a number of factors that "could" affect the amount of appropriate coverage for it compared to other companies, there is no evidence those factors applied to the Company more than others in the peer group or that those other companies do not face risks comparable to those the Company faces. It dismisses the Company's reference to advice of insurance experts on the ground the experts did not submit testimony and were not subject to cross-examination. NYECC discounts the contention that the 2007 Towers Perrin study

identifies utilities as more “susceptible” to D&O claims than other classes of businesses by citing the study’s very expansive definition of susceptibility and pointing out that, under that definition, the Company itself has zero susceptibility to claims.

Opposing the Company’s arguments about the calculation of the premium allowance in the recommended decision, NYECC supports the allowance in the recommended decision on the grounds that the 2007 Towers Perrin shows the premium the Company would pay in the Rate Year for \$300 million in D&O coverage is excessive compared to other public companies with assets or market capitalization of more than \$10 billion and should be lower because of the Company’s more favorable zero claim susceptibility and claim frequency for the last 10 years and that the trend in premiums is decreasing (Ex. 260, pp. 6, 33, 34, 52, 53).

DPS Staff excepts to the judges’ recommendation that 90% of the electric department’s share of the D&O premium be reflected in rates.¹²³ DPS Staff maintains that its proposed allowance of only 10% of the applicable premium amount is appropriate because if a court finds a director or officer committed a wrongful act, that act need not be found illegal or fraudulent to be found imprudent. It argues that it would be unreasonable to require ratepayers to pay for a court judgment resulting from a wrongful act by a director or officer, therefore neither should the cost of insurance to protect against such payment be borne by ratepayers.

The Company opposes DPS Staff’s exception.¹²⁴ It says DPS Staff focuses on whether imprudent acts might be covered by D&O insurance, ignoring the recommended decision’s acknowledgement that the insurance can cover acts that are “less

¹²³ DPS Staff’s BoE, pp. 27-28.

¹²⁴ The Company’s BoE, pp. 22-25.

than perfect but not imprudent.” The Company states that despite incidents covered by prudence proceedings, the Company has faced no D&O insurance claims in the last 10 years and its premiums have not increased as a result of the prudence incidents (Tr. 1769, 1811-12; Ex. 397, sheet 4). If a prudence proceeding did cause a premium increase, the Company maintains, the issue would be whether ratepayers should bear the resulting increased cost of insurance, not the basic cost in the absence of imprudence, claiming that in the 2008 Rate Order we rejected similar attempts to link D&O insurance costs to incidents and prudence investigations.¹²⁵ The Company says DPS Staff does not dispute that nearly all companies have D&O insurance, it is necessary to attract and retain directors and officers, and is similar to protection provided to public officials through taxpayer indemnification.¹²⁶ The Company repeats its argument that there is no basis for trying to separate ratepayer and investor benefits from D&O insurance and that we have historically recognized insurance cost as a fundamental business cost reducing the risk and cost of utility service. The Company concludes by contending that in the 2008 Rate Order we entertained the possibility of a future cap on D&O insurance, but never suggested it was not a legitimate business expense fully recoverable in rates.¹²⁷

b. Discussion

There is substantial evidence in the form of surveys of various public companies and Company-designated peer group utilities to support the recommendation that the Company’s coverage is higher than reasonable and should be lowered by about \$100 million, to \$200 million. The Company’s claims about

¹²⁵ Citing 2008 Rate Order, p. 51.

¹²⁶ Citing Public Officers Law §§17-18.

¹²⁷ Citing 2008 Rate Order, pp. 51-52.

factors that might affect it compared to other companies might distinguish a number of companies in the general survey, but are not credible with respect to the utilities in the group the Company itself selected and designated as peers.

The Company focuses on only two of more than 22 companies in the peer group in Ex. 294.¹²⁸ Those two companies are not a representative sample. Looking at only those two ignores other utilities with greater market capitalization and equivalent or lower coverage than the Company's. As NYECC suggests, there is no evidence that the factors the Company argues could affect the amount of appropriate coverage for it compared to others apply to the Company significantly differently from others in the peer group, especially those 11 companies with market capitalization over \$10 billion (which the Company emphasizes as an important threshold), or that the risks those other companies face are significantly different from those the Company faces. For those 11 companies, the mean coverage as a percentage of market capitalization was 1.63% and median coverage as a percentage of market capitalization was 1.48%. Applying those percentages to the Company's \$10.3 billion capitalization for 2004 indicates the Company was over-insured by about \$80-\$100 million at the time. Using the same comparison for the entire 22-member peer group suggests the Company was over-insured in 2004 by about \$15 million to \$80 million.

Results for 2005 and 2006 (Ex. 396-B), show that the extent of the Company's over-insurance compared to similar utilities has been increasing. For 2005, looking at the 16 companies in Consolidated Edison's peer group with over \$10 billion capitalization, the mean and median coverage as percentages of market capitalization were 1.36% and 1.32%,

¹²⁸ Exhibit 294 is the same as the table for 2004 in Ex. 396B.

respectively. Applying those percentages to the Company's \$11.3 billion capitalization for 2005 indicates the Company was over-insured by about \$150 million at that time. Using the same comparison for the entire 23-member peer group indicates that the Company was over-insured by about \$90 million (mean) to \$155 million (median). For 2006, the 16 companies in Consolidated Edison's peer group with over \$10 billion capitalization had mean and median coverage as percentages of market capitalization of 1.20% and 1.15%, respectively. Applying those percentages to the Company's \$12.3 billion capitalization for 2006 indicates the Company was over-insured by about \$140 million to \$150 million. Using the same comparison for the entire 22-member peer group suggests that the Company was over-insured by about \$110 million (mean) to \$160 million (median). Thus, comparison of the Company's peer group coverage levels to its own supports the judges' finding that the Company was substantially over-insured. Their recommendation of a coverage limit of \$200 million is reasonable, but conservative, and we adopt it.

Turning to the percentage limit on recovery of the premium allocable to electric operations, DPS Staff's argument for its proposed 90% disallowance focuses too narrowly on the possibility of coverage for imprudent acts. As the recommended decision notes, D&O insurance, like other forms of liability insurance, can cover acts that are not perfect, but do not rise to the level of fraud, illegality, or imprudence. In such circumstances, in the absence of insurance ratepayers might otherwise have to bear resulting costs beyond just the legal defense costs DPS Staff's proposed 10% allowance is intended to address. Moreover, as the Company argues, the record shows it has experienced no claims on its D&O insurance over the last 10 years, despite prudence incidents. On the other hand, D&O insurance also provides substantial protection for shareholders. The latter, moreover, not customers, elect directors and thus

have influence over whether competent directors and officers are in place that customers do not. We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders. We will allow 50% of the cost of \$200 million in insurance coverage in the Company's cost of electric delivery service.¹²⁹

We agree with the Company that the premium share should be recalculated, reflecting the decreasing cost premiums for the multiple layers of coverage that comprise its overall D&O insurance package (Ex. 396-A, response to CPB 20). NYECC's purported opposition actually does not respond to the Company's point about miscalculation of the cost effect of the recommended reduction in coverage level, but rather argues that the premiums the Company is paying are excessive and should be adjusted downward. NYECC made the same argument to the judges, but they were not persuaded, and NYECC did not except timely. Thus, we adopt the Company's recalculation of the cost of \$200 million in coverage as 80% of the \$4.007 million cost of \$300 million in coverage, or \$3.206 million. Of that amount, we will allow 50%, or \$1.603 million, as the share allocable to ratepayers. (The related adjustment to rate base for prepaid insurance is revised accordingly.)

2. Other Insurance Escalation Rate

The Company applied a 5% escalation factor to project Rate Year premiums for other insurance, such as property,

¹²⁹ The Company's allusion to its argument on variable pay, referring to the *Abrams* case, *supra*, as precluding a balancing of customer and investor interests, has no more merit here than it did there.

workers' compensation, business travel, and crime, while DPS Staff advocated escalation by the gross domestic product (GDP) inflation rate of 2.7%. The judges recommended the Company's percentage as accounting for the current financial situation of the insurance industry and historic loss experience.

DPS Staff takes exception.¹³⁰ It maintains that the Company's adverse historic loss experience relates only to excess liability coverage and the recent steam pipe rupture incident, the effects of which have been isolated by the cap we imposed on such insurance.¹³¹ With respect to considerations such as the current financial situation, including the AIG bailout, and other factors the Company cited, DPS Staff states that the Company's position rests solely on internal discussions with its risk management department, unsupported by any empirical evidence or analysis. DPS Staff discounts the recommended decision's reliance on Company reference to hurricane experience and increased heat potential under global warming as unsupported in the record, relating only to property insurance, which is less than 10% of total insurance costs, and, in any event, not a new phenomenon but well-known and factored into the industry's risk assumptions and thus premiums. DPS Staff emphasizes that the Company's insurance expense has actually decreased in each of the three most recent years and the GDP factor is used to escalate most other O&M items.

The Company responds in opposition that its proposed escalation rate was based not only on the judgment of its internal risk management department, but talks with insurers, in light of overall market risk, taking into account recent hurricanes, the current financial crisis in the insurance

¹³⁰ DPS Staff's BoE, pp. 27-30.

¹³¹ Case 08-S-0153, Consolidated Edison Company of New York, Inc. - Steam Pipe Rupture Prudence, Order Adopting the Joint Proposal (issued November 13, 2008).

industry, recent claims in the utility industry, and the Company's own historic loss factor (Tr. 2322-23).¹³² The Company contends that its own property insurance rates have been affected by the risk of hurricanes and its prime insurance rates were affected by filing a claim for customer payments a collection agent failed to remit.¹³³

The Company's argument about adverse effects of its own historic loss experience is not overwhelming. The record does not actually address any specific impact of hurricanes on the Company's own claim history, but only the general effect of hurricanes on the insurance industry. (Beyond that, the Company points only to the single incident where it filed a claim for recovery of its loss on a collection agent's failure to turn over payments received.) The risk of hurricanes, even in the context of increased heat potential from global warming, seems sufficiently well known that it is reasonable to conclude that current premiums reflect it. Moreover, the argument that hurricanes would affect only property insurance, which is but 10% of the Company's total insurance expense, seems well taken.

DPS Staff does not address the Company's testimony that general utility industry claims experience will drive premiums up higher than the general inflation rate. The Company's testimony amounts to just one line, however, and does not include any explanation of the experience to which it refers. In addition, the Company's own insurance premiums have dropped in each of the last three years.

We see no good reason on the record to treat the costs of the Company's general insurance differently from the way we treated health insurance costs in the 2008 Rate Order and the

¹³² The Company's BOE, pp. 25-27.

¹³³ Citing Case 04-M-0629, Consolidated Edison Company of New York, Inc. - Deferral of Uncollected Revenues Due to Failure of CashPoint, filed May 14, 2004.

way the judges recommended health insurance costs be treated here. Our standard practice groups these costs with a number of other costs that might increase or decrease. As we explained in the 2008 Rate Order, we expect the Company, like other utilities, to manage the grouped costs as a whole within the general rate of inflation. We grant DPS Staff's exception.

H. Research & Development Capitalization Adjustment

The Company sought \$20.025 million for research and development (R&D).¹³⁴ DPS Staff proposed an adjustment of \$2.731 million to reflect capitalization of a portion of the R&D expenditures. The judges found both parties' arguments on the issue cryptic and declined to make a recommendation. Solely as a placeholder, their recommended cost of electric delivery service reflected an adjustment half way between the two parties' proposals.

DPS Staff takes exception, explaining that a portion of R&D projects will prove successful and, according to accounting rules, must be capitalized.¹³⁵ Although the projects to be funded for the Rate Year are the same as those for which the 2008 Rate Order authorized funding after applying a capitalization adjustment, DPS Staff maintains that a similar capitalization adjustment must be made for the Rate Year to reflect the portion of Rate Year spending on projects that can be expected to prove successful. Since all of the projects for which the Company seeks funding are the same as in its last electric rate case, DPS Staff applied the same capitalization

¹³⁴ The Company's witness on R&D testified that it was requesting \$19 million (Tr. 3428), the same amount allowed in the 2008 Rate Order after accepting a \$2.7 million capitalization adjustment. Its accounting panel presented a request of \$20.025 million. The difference represents the Company's application of its 7.78% labor escalation and 5.19% general escalation to forecast total R&D expenditures for the Rate Year to the base amount (Ex. 5, Sched. 1, p. 3).

¹³⁵ DPS Staff's BoE, pp. 31-32.

ratio that the 2008 Rate Order applied to the Company's R&D request.

In opposition to DPS Staff's exception, the Company begins by reiterating that the projects to which DPS Staff applies its proposed adjustment are the same ones to which the adjustment was applied in the last electric rate case.¹³⁶ It contends its request in this case has effectively already accepted that adjustment again here by requesting only \$19 million, the amount we approved then after deducting \$2.7 million for capitalization. Thus, the Company argues that DPS Staff's proposed adjustment is duplicative. The Company contends that, in any event, DPS Staff's proposed adjustment amounts to a capitalization rate of 13.5% (\$2.7 million on a \$20 million program), far out of proportion to the historic rate of 4.6% that the Company has realized on its R&D expenditures over the last five years.

The Company also takes exception.¹³⁷ Although it maintains any adjustment at all is unwarranted, it limits its exception to the level of the adjustment reflected in the recommended decision. It observes that its total R&D capitalization credits for the last five years amounted to only \$2.3 million, an annual average of just \$465,000 (Tr. 3463). Thus, it contends, even assuming a capitalization adjustment is justified, the \$1.365 million placeholder in the recommended decision is grossly overstated and results in a lower level of rate relief than we allowed for the same level of activity in the 2008 Rate Order. The Company maintains any adjustment should be no more than \$465,000.

In response to the Company's argument that the placeholder reflected in the recommended decision (and, by implication, the greater adjustment DPS Staff proposes) is much

¹³⁶ The Company's BOE, pp. 35-37.

¹³⁷ The Company's BoE, p. 34.

higher than the \$465,000 in annual capitalization credits its R&D program has realized on average over the last five years, DPS Staff says that the Rate Year forecast R&D expenditures are nearly twice the Test Year level and thus higher capitalization amounts for successful projects may reasonably be anticipated in the Rate Year.¹³⁸

The Company has not cited anything in its accounting exhibits or elsewhere in the record that shows it has already capitalized the \$2.7 million. Therefore, we cannot conclude that it has already reflected a sufficient capitalization adjustment in its request.

DPS Staff's proposed \$2.731 million adjustment represents a 13.5% capitalization rate on the Company's \$20.35 million request. The recommended decision's placeholder of \$1.365 million represents a 6.7% capitalization rate. Both ratios significantly exceed the capitalization rate the Company has averaged in recent years. Nothing in the record suggests any change in circumstances that would lead to a higher rate of capitalization in the Rate Year than has prevailed over the recent historical period. Thus, DPS Staff's proposed adjustment seems excessive, while the judges' amount was only a temporary placeholder rather than a recommendation on the merits.

On the other hand, the Company's proposed capitalization amount of \$465,000 based solely on the average dollar amount (rather than percentage) of R&D expenditures capitalized over the last five years is too low, given that the proposed level of R&D expenditures in the Rate Year is approximately double the average level for the last five years, including the Test Year. We find it reasonable to assume that a similar relationship will prevail in the Rate Year as has over the recent historical period. Since the Rate Year spending

¹³⁸ DPS Staff's BOE, p. 23.

level for R&D will be approximately double the average recent historical spending level, we conclude that a capitalization adjustment of twice the average capitalization amount over the same period, or \$930,000, should be applied to the Company's R&D expenditures.

I. Regulatory Commission Expense

DPS Staff proposed a downward adjustment of \$677,000 to remove two cost items from the three-year historic average for regulatory commission expenses, arguing they are non-recurring: the 2003 electric rate case and the 2007 electric emergency outage response program audit. The recommended decision found it pointless to normalize the cost of one rate case out of the historic expense average, only to add back rate case expenses in the Rate Year. The judges also found that, although the specific Vantage emergency outage preparedness audit costs were non-recurring, a similar type of review of plant in service is currently under way and it is reasonable to expect replacement costs in the Rate Year for comparable sorts of audit or review.

DPS Staff excepts to the judges' recommendation against its normalization of emergency preparedness audit costs.¹³⁹ It maintains that the recommended decision found that costs of the "comprehensive management audit" of the Company would be replaced by similar costs. DPS Staff argues that conclusion erred, because the 2008 Rate Order included a special recovery mechanism for comprehensive management audit actual costs, up to \$1.36 million, as incurred, outside base rates through the Monthly Adjustment Clause.

¹³⁹ DPS Staff BoE, p. 32. Although DPS Staff's Brief on Exceptions cites the figure \$1.1 million, its trial brief and the transcript indicate the adjustment amounted to \$0.667 million. Tr. 2725-26; DPS Staff's Initial Brief, p. 144.

The Company responds that DPS Staff misconstrues the recommended decision.¹⁴⁰ It points out that the recommended decision refers to the audit of plant in service pursuant to our 2008 Rate Order's requirement for review of its capital expenditures; and that by the reference to "temporary rates" the judges meant rates being collected subject to refund under that order. The "comprehensive management audit" for which DPS Staff cites a special cost recovery mechanism was not undertaken pursuant to the 2008 Rate Order, the Company notes, but was initiated in Case 08-M-0152. The Company argues that there is no special cost recovery mechanism for the capital expenditure review or a number of other regulatory investigations it cites from the recent past. Thus, the Company says, the judges' conclusion and recommendation were correct.

DPS Staff does refer to the wrong audit, as the Company argues. The judges' references to the 2008 Rate Order and plant in service and temporary rates can only reasonably be interpreted to refer to the review of capital expenditures subject to refund in that order, not to the comprehensive management audit that is just drawing to a close now. As the judges anticipated, the Company will incur costs of other, similar regulatory reviews in the Rate Year, which would replace the costs of the Vantage emergency preparedness costs captured in the Test Year and for which there is no special recovery mechanism. The judges' expectation has been fulfilled already, since we have recently initiated a prudence proceeding in connection with allegations of kickbacks from some Company

¹⁴⁰ The Company's BOE, pp. 37-38.

contractors to some of its employees, for which the Company will incur costs in the Rate Year.¹⁴¹ We deny DPS Staff's exception.

J. Energy Efficiency Related Programs

The judges recommended against DPS Staff proposals that \$0.400 million in costs of energy efficiency R&D, about \$2.5 million in O&M expenses related to demand side management and energy efficiency programs administration, training, market research, and website development costs and smart electric technologies pilot programs, and capital investment of about \$2.1 million in 2009 and \$1.1 million in 2010 for information technology infrastructure to support planning, implementation, and evaluation of energy technology programs all be disallowed in this case and instead be considered in the EEPs case. The recommended decision found that: nothing in our June 2008 order in that case¹⁴² precluded consideration of recovery of energy efficiency infrastructure costs in base rates; and that the Company needs basic infrastructure to administer its existing demand response programs and will very likely need that infrastructure for expanded energy efficiency programs.

DPS Staff takes exception.¹⁴³ First, it states that, given the continuing EEPs proceeding, it did not review underlying EEPs program costs in this case. Second, DPS Staff argues that the extent to which administrative costs the Company requests here in base rates have been addressed in the EEPs case

¹⁴¹ Case 09-M-0114, Consolidated Edison Company of New York, Inc. - Prudence of Certain Capital Program and Operation and Maintenance Expenditures, Order Commencing Prudence Proceeding and Requiring Report (issued February 12, 2009). This subject is discussed further in XI (N) below.

¹⁴² Case 07-M-0548, supra, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs (issued June 23, 2008) (EEPs Order).

¹⁴³ DPS Staff's BoE, pp. 32-33.

by means of our January 2009 "Fast Track" Order¹⁴⁴ is unclear. It claims that allowing base rate recovery will hamper comprehensive measurement of EEPS program costs and benefits targeted in the Fast Track Order, possibly leading to double recovery of costs and difficulty in measuring energy savings of particular programs.

The Company responds in opposition, first, noting that DPS Staff fails to take exception to the recommended decision's rejection of its arguments below and instead raises arguments not made before.¹⁴⁵ Responding to those new arguments, the Company says that DPS Staff had ample opportunity to review the costs in question in this proceeding and its decision not to do so provides no justification for deferring those costs to the EEPS case, which would be prejudicial to the Company. With respect to DPS Staff's arguments based on the Fast Track Order, the Company contends that: DPS Staff points to no aspect of the order that is unclear; the order does not address basic administrative costs for infrastructure or recovery of those costs; and the administrative costs included in the order are for the specific, limited Fast Track programs, not basic infrastructure to support efficiency and demand response generally. It adds that DPS Staff neither explains nor supports the claim that recovery of general administrative infrastructure costs here could result in double recovery. Finally, the Company denies DPS Staff's contention that allowing base rate recovery will impede comprehensive measurement of program costs and benefits targeted in the Fast Track order as unfounded and unexplained. It notes that the recommended decision took no position on how these costs should be treated in evaluating

¹⁴⁴ Cases 08-E-1007 et al., Consolidated Edison Company of New York, Inc. - "Fast Track", Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs with Modifications (issued January 16, 2009)(Fast Track Order).

¹⁴⁵ The Company's BOE, pp. 38-40.

cost-effectiveness of the Company's energy efficiency programs, leaving their consideration for measurement purposes open.

The Company is correct that no language in either the EEPS Order or the Fast Track Order expressly precludes considering its base energy efficiency costs here. Nonetheless, we are concerned that allowing these costs in rates here could make it more difficult to keep track of them in addressing cost recovery and cost-effectiveness evaluations of energy efficiency programs in the EEPS proceedings. In our judgment, it is preferable for the Company to pursue recovery of these costs through the mechanisms established in those proceedings. Accordingly, we will disallow the costs in question here.

K. Correction for System Benefit Charge Expenses

On exceptions, the Company advises that its updated \$819.024 million revenue request as of the time of the hearings reflects \$24 million of system benefit charge (SBC) revenues, but not an offsetting expense of the same amount to reflect that all the SBC revenues will be turned over to the New York State Energy Research and Development Authority. Accordingly, it suggests the final revenue requirement determination should be corrected to reflect this expense.¹⁴⁶

DPS Staff has no objection to the proposed correction,¹⁴⁷ and it is reflected in our revenue requirement calculations.

VI. TAXES OTHER THAN INCOME TAXES

A. Property Tax Expense Level

Property tax expense increases are one of the major drivers of the Company's request for increased electric revenues. At the time trial arguments were submitted to the

¹⁴⁶ The Company's BoE, pp. 24-25.

¹⁴⁷ DPS Staff's BOE, p. 38, n. 32.

judges, the Company was requesting \$1.031 billion for the Rate Year or \$86.7 million more than DPS Staff supported.

Much of the difference between the two parties was eliminated when, going beyond the 7% increase the Company had forecast and that DPS Staff had opposed, New York City increased its property taxes in the middle of a tax year by 7.5% effective January 1, 2009. DPS Staff does not dispute the update. As to the balance in dispute, the judges:

1. Agreed that property tax expense forecasts based on five-year historic averages were previously adopted for the Company, but found that this occurred primarily in the context of the adoption of the terms of joint proposals. A forecast based on a five-year historic average was also adopted in the 2008 Rate Order, in the context of a litigated rate case. But that order did not discuss expressly whether this is the exclusive method that ought to be used to forecast property tax expense. It stated that "the best estimate" ought to be used.
2. Suggested that there is nothing inherently wrong with relying on information in addition to historic rates of change, whether that other information supports a forecast property tax expense increase or decrease. The likely impact of the current economic downturn on municipal taxing authorities is an example of such information, because taxing authorities will be under pressure to make up lost revenues.
3. Recommended, in sum, that the property tax expense allowance in these cases be based on the latest known actual information, including the latest known Handy Whitman Index, and the Company's forecast for other variables for which known information would not be available.

The Company excepts to a \$14.299 million downward adjustment in the recommended decision based on use of the latest Handy Whitman Index, observing that no explanation was provided for ignoring its estimate of future changes in the Handy Whitman Index.¹⁴⁸ It simultaneously states that this exception may be moot because it received from New York City on

¹⁴⁸ The Company's BoE, pp. 35-36.

January 23, 2009 tentative assessments for Real Estate of Utility Corporation (REUC) property that may make it unnecessary to use its forecast.

The Company argues that in the event we decline to rely on the recent information, we should adopt in the alternative the Company's forecast for a 9.5% increase in the Handy Whitman Index as that forecast is based on five-years of actual data (2%, 12%, 6%, 9%, and 8%¹⁴⁹) in the period 2003 through 2007 with no adjustment for judgment being necessary.

DPS Staff does not reply.

Our property tax expense allowance reflects the actual assessed values for utility property that were issued by New York City on January 23, 2009. This moots the Company's exception.

DPS Staff also excepts insofar as the judges recommended reliance on the Company's forecast for the portion of property tax expense that will not be known at the time of our decision. DPS Staff's arguments in support of a downward revenue requirement adjustment of approximately \$11.5 million are as follows:¹⁵⁰

- a. A property tax expense forecast based on a five-year historic average was adopted in the 2008 Rate Order. The issue was litigated in that case and the judges' recommendation was adopted.
- b. The reference in the 2008 Rate Order to use of the best estimate was in connection with a discussion about property tax expense reconciliation. The best estimate in that case was based on the five-year historic average.
- c. It makes sense to rely on a consistent method (using a five-year historic average) because actual tax rates that differ from the forecasts will be reflected in future forecasts, ultimately making

¹⁴⁹ Tr. 2744.

¹⁵⁰ DPS Staff's BoE, pp. 34-35.

ratepayers and the Company whole for differences between forecasts and actuals.

The Company opposes DPS Staff's exception for the following reasons:¹⁵¹

- a. The recommended decision is correct that there was no Commission deliberation on this issue in the Company's last electric rate case because no exception was taken to the judges' related recommendations. Decisions to use a forecast based on a five-year average prior to that time were in the context of cases in which the property tax expense terms of joint proposals were adopted.
- b. The five-year average DPS Staff relied on in the Company's last and current electric rate cases were computed differently, undermining DPS Staff's contention that a consistent approach ought to be used.
- c. That the statement in the 2008 Rate Order endorsing use of the "best estimate" was in a section concerning the reconciliation of estimated and actual property taxes does not undermine the stated principle.
- d. DPS Staff's exception ignores the judges' conclusion that we would not and should not ignore information pointing to a decrease in property tax expense that differs from historic average rates of change.
- e. DPS Staff is inconsistent to reject use of a five-year average to forecast changes in the Handy Whitman Index but to insist that a five-year average must otherwise be used to forecast other components of property tax expense.

We stand by the prior holding that the best estimate should be employed when forecasting future property tax expense. Current expectations are that there is and will continue to be pressure on taxing authorities to increase revenues through new or higher taxes to replace revenues lost as a result of the economic downturn. We are also confident that if there were reasons to expect taxing authorities to be awash with cash, we

¹⁵¹ The Company's BOE, pp. 40-42.

would not feel bound to forecast based on historic rates of change. DPS Staff's exception is denied.

As noted above in Section III, our revenue requirement calculations reflect property tax expense updates provided by the Company, including some provided after the briefs on exceptions.

B. Reconciliation of Property Taxes

The judges noted that bilateral reconciliation of property tax expense was not adopted in the Company's last electric rate case but that such reconciliations have been allowed in all years of numerous multi-year rate plans, including the first year. Given the current economic upheaval, uncertainty about how long the upheaval will last, and about how municipal taxing authorities will respond, the judges supported the Company's bilateral reconciliation proposal in the current cases.¹⁵² The judges suggested that such an approach would also be consistent with an overall regulatory approach of simultaneously minimizing the Company's downside earnings risk and its upside earnings potential.¹⁵³ Their recommendation reflected, among other things, that property tax expenses are very large, potentially volatile, and, to a great extent, beyond the Company's control.¹⁵⁴

DPS Staff excepts, arguing:¹⁵⁵

- a. Full or bilateral reconciliation of property tax expense is not appropriate as the expense is largely known and the Company would be left with no

¹⁵² DPS Staff suggests the judges' reconciliation recommendation was broader, applying to all non-income taxes. However, the only litigated issue under non-income taxes concerned property taxes. The judges' reconciliation recommendation is limited to that issue.

¹⁵³ R.D., pp. 202-203.

¹⁵⁴ Id., p. 10.

¹⁵⁵ DPS Staff's BoE, pp. 35-36.

incentive to minimize the impact of this large expense that comprises 29% of the Company's delivery service revenue requirement.

- b. The judges are inconsistent to ignore this problem while citing the Company's loss of an incentive to control costs as a reason for recommending against bilateral reconciliation of costs related to municipal infrastructure work (RD, p. 185).

The Company opposes DPS Staff's exception, stating:¹⁵⁶

- a. There is uncontroverted evidence on the record about the Company's extensive efforts to minimize property tax expenses.
- b. DPS Staff is inconsistent because it routinely supports bilateral reconciliation of property tax expense in the context of multi-year rate plans.
- c. DPS Staff is inconsistent because if all of the actual Rate Year information were known, there would be no dispute about the level of Rate Year property tax expense.

Property tax expense is clearly one of the largest elements of the Company's cost of providing electric delivery service. Accordingly, the implications of being wrong in a forecast for this expense are likewise greater relative to other elements of revenue requirements, both for ratepayers and shareholders. Given the economic downturn, and relatively greater uncertainty about how long the downturn will last and how municipal taxing authorities will respond, full or bilateral reconciliation of property tax expense makes more sense in these cases than most.

We share DPS Staff's concern about removing an incentive for the Company to minimize its property tax expenses. However, the record in these cases shows that the Company has aggressively sought to minimize its property tax assessments.¹⁵⁷ Indeed, there is no assertion to the contrary. Moreover, our long standing policy is that a utility will be allowed to retain

¹⁵⁶ The Company's BOE, pp. 42-43.

¹⁵⁷ Tr. 1550 and Exs. 35 and 36.

a share of property tax refunds, frequently in the 10-15% range, to the extent it can be established conclusively that the utility's efforts contributed to that outcome. Taking these two factors into account, we conclude that the Company already has and will retain an incentive to minimize its property tax assessments.

Given the magnitude of the Company's property taxes, the relative uncertainty about the impacts of the economic downturn that we consider unique, and that the Company will continue to have an incentive to minimize its property tax assessments, we are adopting the judges' recommendation for full or bilateral reconciliation of property taxes. Exceptions to the contrary are denied.

C. 2008 Property Tax Deferral

The Company seeks permission to recover over three rate years a total of approximately \$75 million of property taxes it is incurring in the current rate year in excess of what is currently allowed in electric rates. DPS Staff opposes the proposal, pending review of the Company's deferral petition in another case (08-M-0901).

The judges declined to support the Company proposal as it would require them to prejudge the outcome of the other case, which is not before them.¹⁵⁸ The judges urged that a decision be made in the other case, if possible, so that the results could be reflected here.

The Company excepts, arguing:¹⁵⁹

- a. It would be more reasonable to reflect the costs as being allowed, subject to possible reversal later, as this is what the Company did with respect to various credits reflected in its revenue requirement calculation, even though such credits may or may not come to fruition.

¹⁵⁸ R.D., p. 203.

¹⁵⁹ The Company's BoE, pp. 36-38.

- b. It would have to finance the approximately \$75 million until the other case is resolved, increasing nominal costs that might have to be recovered from customers, and this argues for prompt resolution of the other case.
- c. The Company introduced evidence projecting a return on equity of less than 9.1% in the current rate year, there is no evidence to the contrary, and the 9.1%, in any event, is clearly inadequate in light of current economic circumstances.
- d. The Company's proposal is ameliorated to the extent it seeks recovery over three years of an amount forgone in one year.

DPS Staff replies as follows: ¹⁶⁰

- a. As updated to reflect the mid-year 7.5% New York City property tax increase effective on January 1, 2009, the Company is now seeking deferral of \$76.4 million in the separate case.
- b. The Company conceded during the hearings that it earned 9.3% for the 12 months ending September 30, 2008. ¹⁶¹
- c. It would be unfair to customers to grant the Company's request while it is "currently earning above its allowed ROE." ¹⁶²
- d. There is nothing in the record to substantiate the Company's claim that its cost of common equity exceeds 9.1% and, in any event, adoption of such a contention would amount to improper retroactive ratemaking.

A decision on the Company's deferral petition will be made in Case 08-M-0901. DPS Staff will not be able to offer a recommendation in that separate case until after the Company's actual earnings are known for the current rate year, or the 12 months ending March 31, 2009. Accordingly, it is not possible as a practical matter to decide the other case in time to

¹⁶⁰ DPS Staff's BOE, pp. 24-25.

¹⁶¹ This reflects equity earnings in the last quarter of 2007 and the first quarter of 2008, both of which are prior to the current rate year.

¹⁶² DPS Staff's BOE, p. 24. Given the prior note, the basis for this statement is not known.

reflect the results here. The judges' recommendation is adopted and the Company's exception is denied.

D. Minimizing Future Property Taxes

While we are fully satisfied with the resolution of the three key property tax issues litigated in these cases, an issue not raised by the parties is whether more needs to be done to bring the Company's total property tax expense more in line with that experienced by other utilities in big cities outside New York as well as by other New York utilities.

Publicly available information in 2007 FERC Form 1, for example, shows that the Company's property taxes are about 10% of its operating revenue while utilities in Pittsburgh, New Orleans, Tampa, Washington DC, Detroit, and Baltimore incurred property taxes in the range of 0.10% to 2.8% of operating revenues in the same period.

A similar comparison among New York electric utilities shows that more than 20% of the Company's total electric delivery revenue requirement comprises property tax expense while that percentage is in the range of approximately 8% to 12% for other electric and combination utilities in this state.

Going further, an examination of New York City tax rates for the residential (Class 1), large residential building (Class 2), utility property (Class 3), and commercial/industrial (Class 4) shows that Class 3 (of which the Company is approximately 75%) pays a high tax rate relative to the three other classes and that the cumulative tax rate for this class has jumped 33.8% over the last ten years compared to a 6.2% rate of increase for Class 4 over the same period.

In sum, it appears the Company's ratepayers are being forced to contribute a disproportionate share of the total property tax revenues in the Company's service territory, undermining the ability of many customers to pay for an essential service.

In this light, we want to examine all the steps the Company is taking to restrain the growth of real property tax expense beyond contesting assessments. For this reason, the Company is required to include in its next major electric rate case filing, or by not later than 30 calendar days after that filing, testimony explaining how its real property is defined and classified, the amount or value of its real property subject to such taxation, the general uses of such real property, the history of the value of its property and tax rates over the last ten tax years, whether and to what extent its tax rates are consistent with those paid by other New York City and Westchester businesses, and, to the extent there are inconsistencies in taxation, identifying actions that have been and could be taken to address the situation. We plan to review that information and any responsive submissions, on a schedule to be determined by the judge in the Company's next rate case. We believe the Company should be afforded an opportunity to enjoy a share of any net savings realized in the event any reclassification and reduction in the disparity compared to other tax classes results from its initiative, while holding the line or better on property tax assessments.

VII. DEPRECIATION - PAYGO

A. Background

Negative salvage costs are labor and other costs incurred to remove a piece of plant from service that exceed the positive salvage value of the piece of plant being removed. As a matter of principle, the current ratemaking approach is for the Company to accrue negative salvage costs and to recover such costs in rates gradually over the useful life of the piece of plant to be removed from service in the future. Estimates of future salvage costs are made for this purpose and updated from time to time so that the correct amount will be recovered from customers before the removal costs are actually incurred.

As a practical matter, however, rates are not always increased in lock step with updated estimates of future negative salvage costs because of concerns about the magnitude of the resulting revenue increase on current customers. This can lead to an increase in the size of a utility's depreciation reserve deficiency, an amount the Company is fully expected to be allowed to recover from ratepayers in the future.

There is record evidence that the Company has a depreciation reserve deficiency of at least \$670 million as of the end of 2007. As part of its proposal to ameliorate impacts on customers in these cases, the Company postponed to the future a request to increase depreciation expense and revenues by approximately \$55 million per year.

The NYC Government Customers and Westchester County had both proposed adoption of a new principle under which ratepayers would pay for negative salvage costs only after they are incurred by the Company, or on a pay-as-you-go or PAYGO basis. Two key effects of such a change in the short run are that the Company's \$670 million depreciation reserve deficiency would be converted into a surplus of approximately \$330 million and annual depreciation expense and revenue requirement could each be reduced by \$70 million for about three years. The Company and DPS Staff oppose adoption of the new principle.

The judges recommended against adoption of the PAYGO method for the following reasons:¹⁶³

1. Current customers should contribute to the future cost of removal of plant used to serve such customers today. To the extent some or all of such costs of removal are recovered in the future, they become an unwarranted burden on customers taking service at that time.
2. A \$70 million electric revenue reduction that would be sustainable for approximately three years under PAYGO would be followed by incrementally greater electric

¹⁶³ R.D., pp. 214-216.

revenue increases in year four and beyond. In other words, if ratepayers pay less now to cover negative salvage costs, they will at a later date need to pay more toward such costs.

3. PAYGO would increase the Company's external financing requirements by approximately \$50 million per year and decrease internally-generated cash flow at a time when the Company is in the midst of a very large construction program.
4. The current method offers the advantages of spreading out cost recovery over time and of allowing for periodic updates to reflect changes in estimates of negative salvage costs and to reflect those updated estimates in rates as feasible.
5. Given existing circumstances, the Company has established that ratepayers enjoy tax advantages under the current approach that exceed those under the PAYGO method.

B. The Arguments

The NYC Government Customers except, arguing:¹⁶⁴

- a. A rational, equitable way to reduce revenue requirement by \$70 million annually in the short run should be embraced given the desperate economic situation facing the country.
- b. PAYGO is used in several states, including New Jersey and Pennsylvania.
- c. PAYGO is superior because the Company could be permitted to recover all of its current negative salvage costs in rates. The current approach, as applied, does not allow the Company full recovery in current rates for estimated future negative salvage costs.
- d. A \$70 million electric revenue decrease now for this item alone, followed by a \$130 million revenue increase in three years, is superior to no revenue decrease now and annual revenue increases in the future of approximately \$670 million for the Company to recover forecast increases in negative salvage costs as well as to amortize over 10 years a reserve deficiency that is projected to exceed \$3.7 billion.
- e. PAYGO would not contribute to intergenerational inequity because current customers would continue to be responsible for actual negative salvage costs

¹⁶⁴ The NYC Government Customers' BoE, pp. 14-23.

incurred now and future customers would be responsible for actual negative salvage costs incurred in the future.

- f. In any event, PAYGO does not create any intergenerational inequity in comparison to the existing approach, as applied, under which substantial increases in forecast negative salvage costs are not being recovered in rates currently. There is also no increase in intergenerational inequity for a change to PAYGO for the Company's "mass accounts" in which thousands or millions of pieces of plant are constantly being placed in and taken out of service in each rate year.
- g. An incremental \$50 million to be financed by the Company each year is dwarfed by the Company's \$1.0 billion per year capital spending over the last five years.
- h. Estimates of current negative salvage costs can be updated under PAYGO just as easily as forecasts of future negative salvage costs can be updated under the existing approach.
- i. The judges' analysis of the income tax advantages is premised on current circumstances under which a large depreciation reserve deficiency has built up and forecast negative salvage costs are not being fully recovered in rates. The existing approach is not sustainable and an unreasonable basis for a proper comparison of the income tax implications of the two competing approaches.
- j. The income tax analysis is also suspect because the Company flows through to customers all the tax benefits of negative salvage costs already paid for by ratepayers, but flows through to customers only a portion of the tax benefits of the PAYGO approach.

The Company and DPS Staff generally endorse the judges' recommendations. The Company emphasizes that the issue presented solely concerns the timing of negative salvage cost recovery and that there is no dispute about the total amount of negative salvage costs to be recovered ultimately. It also criticizes the NYC Government Customers' failure to acknowledge the Company's proposal to ameliorate customers' bills now by delaying recovery of increasing negative salvage costs. DPS

Staff adds that adoption of the PAYGO method would likely result in wide swings on the Company's income statement and increase the risk that the Company might not fully recover its actual negative salvage costs. The reasoning behind the latter contentions is not explained.

In response to the NYC Government Customers' arguments above, the Company and DPS Staff offer the following:¹⁶⁵

- a. NYC Government Customers cloud the issue by focusing on a \$70 million revenue decrease and de-emphasizing that this will have to be made up by larger rate increases later.
- b. The existing method is used in the vast majority of regulatory jurisdictions.
- c. Whether the basic principle followed is that current or future customers should be responsible for the recovery of negative salvage costs for plant in use today, there can be a mismatch between costs incurred and costs recovered in rates depending on the level of rate recovery allowed by the Commission. The NYC Government Customers incorrectly suggest adoption of PAYGO guarantees current recovery of negative salvage costs as they are incurred. Indeed, those customers expressly acknowledge that there could be circumstances under which all current negative salvage costs might not be allowed in rates immediately even if PAYGO were adopted.
- d. While the existing approach as applied does result in some intergenerational inequity, this problem would clearly be exacerbated by adoption of the PAYGO method.
- e. Full flow through to ratepayers of the tax deduction effects of actual negative salvage costs is appropriate now because customers already paid such costs in rates. Such a flow through to ratepayers is not appropriate if PAYGO is adopted, because ratepayers will not have paid all of the underlying costs in the year in which they are incurred and deducted for income tax purposes.

¹⁶⁵ The Company's BOE, pp. 43-47 and DPS Staff's BOE, pp. 39-41.

C. Discussion

The most significant effect of adopting the PAYGO approach as a matter of policy would be that all negative salvage costs associated with plant now serving existing customers would be shifted to those who are Company customers at or after the time such negative salvage costs are actually incurred. We are not persuaded by the NYC Government Customers' arguments that such a shift in cost responsibility would be equitable.

Putting aside this problem, the NYC Government Customers have not established that the proposed policy change would be beneficial to customers over the long term as measured on a net present value basis today.

The NYC Government Customers are also wrong to compare the pros and cons of the current policy, as implemented to ameliorate ratepayer impacts, to the proposed policy assuming it would never be unnecessary to ameliorate ratepayer impacts. No basis has been provided for such an assumption.

Turning to the income tax implications of the proposed policy change, we are persuaded by the Company's arguments that customers that pay in advance a portion of negative salvage costs to be incurred in the future should enjoy the benefits of the associated income tax deduction. If ratepayers pay negative salvage costs after they are incurred, they should enjoy the benefits of any associated income tax deduction only to the extent they will have fully paid such costs in rates. In sum, the judges' recommendation is adopted and the exception of the NYC Government Customers is denied.

On a related matter, we note that the Company's depreciation reserve deficiency is growing and that this will continue during the Rate Year. The Company's next electric rate case filing must summarize its future expectation with respect

to the build up of this reserve and identify the options and timetable it is considering for addressing it.

VIII. COST OF CAPITAL

This section considers issues concerning the Company's Rate Year cost of common equity. There are no exceptions concerning the judges' recommendations in support of a 48% equity capitalization ratio, forecast debt costs, or the reconciliation of debt costs. However, the latter two issues are also addressed below.

A. The Cost of Common Equity and the Sharing Trigger and Cap

1. Background

Through the trial briefing stage, the Company supported an 11.0% equity return allowance (11.3% in the context of a three-year rate plan), but reflected only 10.0% in its May 2008 tariff filing. It is unusual for a utility to support one equity return in testimony and to reflect a lower one in the revenue request set forth in its tariff filing.

The revenue requirement difference between 10.0% and 11.0% is approximately \$115 million per year. The Company described its 10.0% request as part of its proposal to ameliorate bill impacts on customers by approximately \$426 million per year.¹⁶⁶

DPS Staff, CPB, and Westchester each submitted testimony in support of equity return allowances for the Company of 9.5%, 9.91%, and 9.1%, respectively.

Just prior to issuance of the recommended decision, the judges asked the Company, DPS Staff, and CPB to provide updates using their proposed methodologies and recent information. The Company went beyond the judges' request,

¹⁶⁶ Ex. 209, pp. 48-49. As noted above, another \$55 million of the amelioration proposal was to postpone recovery of increased negative salvage costs.

providing both updated information and a revised methodology, calculated an updated/corrected cost of equity of 10.6%, and continued to support 11.0% and its request of 10.0%. DPS Staff used updated information to calculate 9.71%. CPB did not provide any update as its witness was out of the country at the time.

Based on their assessment of all the evidence and arguments, the judges estimated the Company's Rate Year cost of common equity would be 10.35%, subject to an upward adjustment to reflect the quarterly payment of dividends, and subject to further update based on information available at the time of our final decision. Given that the Company requested 10.0% at the time, that is the figure reflected in the judges' cost of service calculations.

The judges followed eight steps to derive the 10.35% and to recommend 10.0%:

1. Endorse use of the proxy group of utilities supported by DPS Staff and CPB and not contested by the Company.
2. Use a two-stage (or two-growth-rate) discounted cash flow (DCF) methodology, share price data for a proxy group of companies for the three months ending November 2008, short-term growth in dividends per Value Line, and a long-term growth rate of 5.6%. The result was 10.29%. It is the latter figure the judges recommended be adjusted using a model (not available to the judges) that reflects the payment of dividends quarterly as had been proposed by the Company rather than annually at the end of the year as had been proposed by DPS Staff.
3. Use the "traditional" Capital Asset Pricing Model (CAPM) and zero-beta CAPM methodologies for the same proxy group of companies, using a beta of 0.81, 30-year Treasury bond yields for the three months ending November 2008 as the risk-free rate, and a market risk premium based on the difference between a market return estimate for the S&P 500 and the risk free rate. The average of the 10.67% CAPM and 11.05% zero-beta CAPM is 10.86%.
4. Give no weight to the results of the Risk Premium Methodology the Company supported or to Westchester's

proposal that we adopt in these cases the same 9.1% equity return allowance authorized for the Company in the 2008 Rate Order.

5. Average the DCF (10.29%) and CAPM (10.86%) results for a return of 10.58%.
6. Reduce the 10.58% by 26.5 basis points (to 10.315%) to reflect that the Company's credit rating is superior to the median credit rating for the proxy group of companies, while recognizing some uncertainty about support for DPS Staff's proposed 53 basis point credit quality adjustment.
7. Increase the 10.315% by four basis points to 10.355% or 10.35%, to permit rate recovery of the Company's likely equity issuance costs.
8. Reflect a 10.0% cost of equity as this is what the Company had requested.

A common theme in the recommended decision's analysis of the DCF and CAPM issues, and the relative weighting of the results of each methodology, is that the judges gave little weight to arguments based on prior decisions of this Commission unless such arguments or the cited decisions explained the substantive reasons behind such prior decisions.

Going beyond the eight steps listed above, the judges recommended adoption of a 10.5% equity earnings sharing trigger, 100% Company retention of equity earnings up to and including 10.5%, 50%/50% equity earnings sharing between shareholders and ratepayers above 10.5% and below 11.0% (exclusive of any positive incentives authorized in these or other cases), and 100% ratepayer retention of equity earnings above 11.0%. The overall goal of the recommended sharing trigger and earnings cap was to give the Company some positive upside earnings potential (to help it maintain an S&P bond rating of "A-") while minimizing the Company's ability to earn more than its cost of equity by spending less on O&M expenses than allowed in rates or by achieving productivity savings far in excess of the 1% they had recommended.

The numerous exceptions to the judges' equity return recommendations are discussed in turn. Subject to any update at the time of the final decision, the Company's basic contention is that the return on equity should be higher than recommended, increasing electric revenue requirement by almost \$71 million per year. DPS Staff is arguing, subject to any update at the time of the final decision, that the return on equity should be lower than recommended, reducing revenue requirement by almost \$33 million per year. CPB's position is close to DPS Staff's, while Westchester argues the return on equity should be much lower, reducing revenue requirement by at least \$107 million per year.

2. The Role of Precedent in General

CPB describes as "most troubling" the judges' suggestion that years of prior decisions should be given very little weight. CPB accurately explains that a generic proceeding was initiated years ago concerning various cost of capital issues. It says that the judges' recommendations in that case have been followed fairly consistently since that time and that this is reasonable to ensure similar issues are resolved consistently in various utility service territories through the state. CPB neither mentions nor comments on the distinction the judges made between arguments based solely on conclusions previously reached, without any explanation of why, and arguments based on evidence or precedent that explains why a particular outcome on an issue makes sense.

DPS Staff likewise criticizes the judges' "unabashed disregard of Commission precedent" that "effectively rewards the Company's intransigence at the expense of well-reasoned and consistent Commission practice."¹⁶⁷ The judges' recommendations that ignore precedent, DPS Staff says, should all be rejected.

¹⁶⁷ DPS Staff's BoE, p. 36.

The Company replies that the Generic Financing case methodology was never formally adopted. Even if it was, the Company continues, that methodology should be reassessed when evidence is presented that modifications are necessary. The current economic downturn alone, it concludes, justifies a re-examination of that methodology.¹⁶⁸

DPS Staff and CPB are both correct that this Commission's practice with respect to return on equity issues has been fairly consistent over a period of at least 14 years. Parties that seek a departure from that practice have a heavy burden that they cannot expect to meet simply by repeating arguments previously rejected.

An issue squarely presented in these cases, however, is whether parties arguing for a continuation of such practices, contrary to proposals to depart from them, need to provide substantive reasons for doing so, either through evidence or by citing to precedent that provides such reasons.¹⁶⁹ We hold that they do.

We readily acknowledge that this requires DPS Staff and other parties to explain positions that may seem reasonable to them, and that are consistent with long-standing practice. We can also appreciate that this might be frustrating given competing demands for resources. However, we have not prohibited utilities from supporting equity return requests in the manner they think proper. We also expect the judges to have a substantive basis for each of their recommendations, something they obviously were interested in providing for us on these issues. Accordingly, to the extent parties are criticizing the judges' refusal to recommend outcomes for which substantive

¹⁶⁸ The Company's BOE, pp. 47-48.

¹⁶⁹ Citations to precedent that do not provide such reasons is not adequate except as a secondary resource.

reasons were not offered on the record or in precedent cited in trial briefs, we conclude those criticisms are unwarranted.

3. DCF Model Issues

The judges' DCF calculations reflect common stock share prices for the three months ending November 30, 2008. They declined to rely on six months of data, and recommended we do the same at the time of our decision, contrary to DPS Staff's and CPB's proposals. In support of this approach, the judges pointed to markedly changed circumstances in financial markets in the September-October 2008 period. They also declined to adopt the Company's proposal to use only a recent, spot share price, as it could be aberrational.

The judges' DCF recommendation also reflects DPS Staff's proposal to use a Value Line forecast of dividend growth through 2012; the Company used a one-growth-rate model and had no competing recommendation. As to long-term or infinite growth expectations, the judges assumed a long-term growth rate of 5.6%, based on Gross Domestic Product growth of 3.4% from 1929 through 2007 plus an inflation rate of 2.2%. The 5.6% is higher than the 5.3% sustainable growth rate that had been proposed by DPS Staff. The judges declined to rely on the 5.3% as it was based on a forecast market return and the judges had been persuaded by the Company's argument that this would be unreasonably circular. The 5.6% is also lower than the 6.0% to 7.6% growth rate that had been proposed by the Company, agreeing with DPS's arguments that such growth rates are not sustainable in the long run.

Using these inputs and DPS Staff's two-growth-rate model, the judges' DCF result was 10.29%.

The Company had criticized DPS Staff's model to the extent it reflects the payment of dividends annually at the end of the year rather than quarterly as they are actually paid. The judges were persuaded by this Company argument, citing the

absence of any substantive argument to the contrary.

Accordingly, they invited the Company to quantify the effect of this change.

As to the recommendation to use three recent months of share prices, CPB has no objection to an update. However, it respectfully disagrees with the recommendations that the update be done using only three months of data, as six months of updated data is typically employed.¹⁷⁰ It observes that use of a longer period helps to reduce the effects of volatility and results in a better alignment with data used to forecast future growth. CPB notes as well that six months' data was used in another decision as recent as August 2006.¹⁷¹

DPS Staff does not say it is excepting, but offers the following:¹⁷²

- a. It is indifferent to the recommendation to use three months of share data.
- b. However, it is not convinced that recent events warrant overturning a convention that has consistently been applied and that is undoubtedly incorporated into investors' return requirements for New York utilities.
- c. On the other hand, the use of three months' data is not a radical shift and might even be preferred as the growth estimates in DPS Staff's model are updated every three months.¹⁷³

¹⁷⁰ CPB's BoE, pp. 5-6.

¹⁷¹ Case 05-E-1222, New York State Electric & Gas Corporation - Rates, Order Adopting Recommended Decision with Modifications (issued August 23, 2006), p. 96.

¹⁷² DPS Staff's BoE, pp. 38-39.

¹⁷³ This may explain why DPS Staff filed testimony in early September 2008 based in part on share prices in the first six months of 2008.

- d. The effect of such a change is de minimis, increasing DPS Staff's updated DCF estimate from 9.91% to 9.94%.¹⁷⁴

The Company does not respond specifically to DPS Staff's and CPB's post-recommended decision arguments concerning share prices.

Turning to long-term or infinite growth expectations, CPB excepts to the proposed rejection of the use of retention growth on account of concerns about unreasonable circularity.¹⁷⁵ In support, it cites a 2007 rate order for Orange and Rockland Utilities, Inc. which states that while forecasts of future earnings used to project growth will consider the return that investors expect regulators to allow, those earnings forecasts also reflect investor expectations about a wide variety of other factors, unrelated to the allowed cost of equity.¹⁷⁶ CPB also states that it opposes use of a long-term growth rate based on Gross Domestic Product, but it offers no reasons.

DPS Staff also excepts, arguing a long-term growth expectation of 5.6% is out of line with the consensus long-run growth rate in the Nominal GDP of 4.8% for 2015-2019, including long-term growth of 2.7% and inflation of 2.1%. The judges are also inconsistent, DPS Staff continues, to rely on historic GDP growth while simultaneously rejecting the Company's 7.1% risk

¹⁷⁴ The .03% change is for the median in DPS Staff's proxy group. The effect of using three months data on the proxy group average DCF-derived equity return is to increase it from 9.73% to 9.96%.

¹⁷⁵ CPB's BoE, p. 7.

¹⁷⁶ Cases 06-E-1433 and 06-E-1547, Orange and Rockland Utilities, Inc. – Rates, Order Setting Permanent Rates, etc. (issued October 18, 2007), p. 10.

premium based on historic information for the same period.¹⁷⁷ Finally, as discussed in greater detail in connection with its arguments against averaging of the DCF and CAPM results, DPS Staff argues that it is reasonable to use an estimate of market returns to estimate retention growth to estimate the median cost of equity for the proxy group. Such circulatory is logical, it contends, as analysts' estimates of future dividends and earnings necessarily reflect assumptions regarding anticipated regulatory action.¹⁷⁸

The Company does not respond specifically to these exceptions by CPB and DPS Staff.

Turning, finally, to whether dividends should be modeled as being paid quarterly or annually, the Company advises that, all other things being equal, the judges' 10.29% DCF result should be adjusted upward by 20 basis points, to 10.49%, to reflect the payment of quarterly dividends.¹⁷⁹

CPB excepts, arguing the approach recommended by the judges has consistently been rejected going back to 1981.¹⁸⁰

¹⁷⁷ DPS Staff's BoE, pp. 40-41. On the last point, DPS Staff is referring to the judges' recommendation to eschew reliance on the Company's market risk premium for the CAPM approach. The Company proposed a risk premium of 7.6% based on the average of a historic 7.1% and a projected 8.1%. Persuaded by DPS Staff arguments, the judges rejected the whole approach because the projected 8.1% was not reliable (R.D., p. 224).

¹⁷⁸ DPS Staff's BoE, pp. 40 and 44.

¹⁷⁹ The Company's BoE, pp. 49-50.

¹⁸⁰ CPB's BoE, p. 6, citing Cases 06-E-1433 and 06-E-1547, supra, Order Establishing Temporary Rates (issued October 18, 2007), p. 11. That order provides no explanation. However, it does state that this Commission would not reject use of current stock prices if historic data is stale. CPB also cites Cases 27561 and 27710, New York Telephone Company - Rates, Opinion No. 81-3 (issued January 19, 1981). That opinion, p. 26, refers to the judges rejecting an adjustment for quarterly dividends to which the utility did not except.

DPS Staff also excepts on the dividend issue, arguing that the judges have a fundamental misunderstanding of DPS Staff's model, confusing it with the standard annual form employed by the Company, as DPS Staff's model does not compute dividend yields. DPS Staff argues as well that it is not practical to apply a quarterly dividend adjustment to a DCF model that is not the standard form. In response to what it describes as the judges' invitation to provide further evidence as to why such an adjustment is warranted, DPS Staff cites the same 1981 precedent as CPB to the effect that investors earn a higher return from quarterly dividends only to the extent they are reinvested in Company shares. DPS Staff contends that regardless of whether or not such dividends are reinvested, regulators do not need to model for and provide an additional return.¹⁸¹

The Company replies that insistence on use of an annual dividend would have us improperly ignore the time value of money and bond math.¹⁸² No further explanation is provided.

Our updated DCF estimate is based in part on DPS Staff's two-growth-rate model and proxy group, both of which are recommended by the judges. We conclude that the judges were properly concerned, in light of dramatic changes in financial markets in October and November 2008, about relying heavily on share price data preceding that period. We find it is appropriate under these circumstances to rely on a more recent time period, but not so short as to introduce undue volatility into the calculation. The three-month average is also logically consistent with the Value Line forecasts that are published over a three-month period. It is reasonable in these circumstances

¹⁸¹ DPS Staff's BoE, p. 39. DPS Staff is referring in part to page 33 of the Recommended Decision in Case 91-M-0509.

¹⁸² The Company's BOE, p. 48.

to rely on the most recent data over a three-month period reasonably close to the Rate Year.

For growth, we are relying in the short run on the most recent Value Line forecast of dividend growth for each company in the proxy group, as recommended by the judges, and an updated sustainable growth rate for each company in the proxy group (the median of which is 5.10%) as proposed by DPS Staff and CPB on exceptions. This is a fundamental measure of a company's growth. Dividends in excess of this level of growth would cause a company's equity balance to deteriorate and dividends less than this level of growth would cause the equity ratio to exceed reasonable levels.

We remain unconvinced by the Company's basic contention, endorsed by the judges, that it is unreasonably circular to assume a cost of equity to estimate retention growth to estimate the cost of equity. As this Commission stated on a prior occasion, while forecasts of future earnings used to project growth will consider the return that investors expect regulators to allow, those earnings forecasts will also reflect investor expectations about a wide variety of other factors, unrelated to the cost of common equity. In particular, we have previously pointed out that, "The retention growth component of the sustainable growth calculation relies on a prediction of expected future earned rates of return on common equity for a proxy group composed mainly of holding companies owning both regulated and unregulated businesses."¹⁸³

We are not adopting the judges' recommendation that our DCF estimates reflect the payment of dividends quarterly rather than annually at the end of each year. Any extra return to be achieved on account of quarterly dividend reinvestment will be achieved by those who actually reinvest all their

¹⁸³ Cases 06-E-1433 and 06-E-1547, supra, Order Setting Permanent Rates, etc. (issued October 18, 2007), p. 10.

dividends in the Company's stock. Any additional allowance would be duplicative for those who actually reinvest dividends and unnecessarily generous to those who do not. Accordingly, the Company's proposed 20-basis point upward adjustment to our DCF results is rejected.

Taking all of the above into account, our updated DCF estimate for the proxy group is 10.47%.

4. The Capital Asset Pricing Model

Inputs to the judges' CAPM estimates include a beta of .81 for the proxy group, three months of recent yields on 30-year Treasury bonds for the risk-free rate, and a market risk premium based on the difference between the forecast market return for the S&P 500 less the risk-free rate.¹⁸⁴

The .81 beta employed by the judges is the average of the .80 proposed by DPS Staff and the .81 proposed by CPB. DPS Staff explains that the .80 it proposed was the median for the selected proxy group, that .81 was the average, and that the median is superior to the average because it diminishes the influence of any outlying individual results.¹⁸⁵ DPS Staff advises as well that in its December 2008 update, the median beta for the proxy group was .80 and the average beta was .77. The rounded average of these two figures, it notes, is .79 rather than the .81 used by the judges. In any event, DPS Staff proposes that the median be used based on market data available through February 2009.

Turning to the risk-free rate, the Company argued it should be based on 30-year Treasury bonds alone, as they are more like common stocks, and that yields on 10-year Treasuries should be ignored for these purposes. The judges noted that no party offered a substantive response to this contention.

¹⁸⁴ R.D., pp. 222-224.

¹⁸⁵ DPS Staff's BoE, pp. 41-42

The recommended decision does not state a reason for using three rather than six months of yields on 30-year Treasuries. As in the case of the DCF analysis, presumably, the judges were concerned about relying too much on data prior to the sharp market downturn in October-November 2008.

As noted above, these inputs resulted in an average estimated cost of equity of 10.86% using the CAPM and zero-beta CAPM methods.

DPS Staff excepts, pointing out that it does not oppose use of 30-year Treasuries alone given that, over time, either approach will result in higher or lower returns. However, it argues 10-year and 30-year Treasury yields should both be used as this is the approach consistently followed for 14 years and that continuation of this approach will ensure unbiased results.

CPB also excepts, arguing we rejected exclusive use of 30-year Treasury bonds in the 2008 Rate Order and that the recommended decision does not provide an adequate reason to justify the proposed change in practice.¹⁸⁶

The Company does not respond to any of these exceptions in detail, arguing generally that it is wrong to rely on the Generic Finance case approach in light of valid criticisms in this case and current and projected volatility in the markets.

Our "traditional" CAPM and zero-beta CAPM estimates are based on the updated (as of February 2009) median beta of .70 for the proxy group. Our risk-free rate of 2.90% is based on the average of 10-year and 30-year Treasury yields for the three months ending February 2009. Three months' data are being used for reasons discussed above. Both 10- and 30-year Treasuries are being employed to recognize that different

¹⁸⁶ CPB's BoE, p. 8.

investors have different time horizons for holding stocks. Stated differently, not all stockholders hold stocks for 30 or more years. Likewise, as recommended by the judges, our market risk premium of 10% is based on the difference between the March 9, 2009 estimated market return of 12.90% for the S&P 500, less the risk-free rate of 2.90%. Accordingly, our traditional CAPM and zero-beta CAPM results are 9.90% and 10.65%, respectively, or an average of 10.28%.

5. Westchester's Exception

On exceptions, Westchester County continues to support a 9.1% allowed return on equity, suggesting such an allowance would be consistent with the returns allowed in 2008 for Orange and Rockland Utilities, Inc. in the context of a three-year electric rate plan, and for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island, respectively, in the context of five-year rate plans. Alternatively, it suggests the allowed equity return should be no higher than 9.5%.¹⁸⁷ Westchester asserts that the judges were overly influenced by the Company's testimony about the negative consequences of an inadequate rate of return. It suggests the 9.1% allowed in the 2008 Rate Order in response to the Company's 11.5% request had no dramatic consequences.

Westchester goes on to suggest that when rate of return issues are decided, consideration should be given to the effects of the economic downturn on ratepayers and that, as indicated by share prices, the Company is weathering the economic downturn better than many other firms.

It states that a 9.1% equity return allowance, all other things being equal, will save ratepayers \$107 million per year and that the Revenue Decoupling Mechanism (RDM) protects the Company's revenues and minimizes its risks.

¹⁸⁷ Westchester's BoE, pp. 7-9.

The Company responds, arguing the judges properly rejected 9.1% as it lacked any analytical support and ignored changed circumstances since the 2008 Rate Order.¹⁸⁸ Consolidated Edison faults the County for failing to recognize that the economic downturn has increased capital costs and that the Company needs to maintain an "A" credit rating to provide safe and reliable service at a reasonable cost. Finally, the Company states that the 2008 downgrade significantly increased its commercial paper costs and that a further downgrade would not have a modest impact. No quantification is provided.

The Company, DPS Staff and CPB have all introduced extensive testimony to the effect that financial circumstances in the Rate Year can be expected to differ from those we envisioned when the 2008 Rate Order was issued. Westchester basically argues that all of this evidence should be ignored on the grounds that the resulting equity return allowance would be higher. This contention is unreasonable on its face and Westchester's exception is denied.

6. Exceptions Concerning Weight

The judges recommended that the DCF and CAPM results be given equal weight because both involve the use of subjective judgment.¹⁸⁹

DPS Staff excepts, arguing that of all the conclusions in the recommended decision concerning the cost of equity, this is perhaps the most ill-conceived.¹⁹⁰ DPS Staff renews its argument that the DCF method has been the principal equity costing method of regulators for many years (including in New York) because the stock price and yield data are readily available and comprise objective indicia of investors' immediate

¹⁸⁸ The Company's BOE, pp. 49-50.

¹⁸⁹ R.D., p. 226.

¹⁹⁰ DPS Staff's BOE, pp. 42-46.

return requirements. DPS Staff acknowledges that it is more challenging to estimate growth and that this involves subjective judgment. According to DPS Staff, however, what the recommended decision fails to acknowledge is that the DCF methodology is nevertheless less subjective than the CAPM approach.

DPS Staff also expresses its suspicion that the recommendations on this issue were swayed by the Company's claims about the DCF underestimating investors' expectations when a firm's market to book ratio exceeds one, and it argues that there is precedent and good reason to reject such a supposition. It notes as well that the Company's updated and flawed CAPM (9.2%) and Risk Premium (9.1%) estimates have fallen by 170 and 90 basis points, respectively, undermining the Company's claims about increasing capital costs.¹⁹¹

Finally, DPS Staff argues that one further example of the poorly conceived and inconsistent nature of the recommended decision's overall conclusion is that if the judges had used the same historical data in its DCF and CAPM analyses, the conclusion would have been 9.75% instead of 10.58%, exclusive of a credit quality adjustment and issuance costs.

CPB excepts to the recommended equal weighting of the DCF and CAPM results,¹⁹² noting that the 2/3 DCF and 1/3 CAPM weighting was endorsed as recently as an October 18, 2007 rate order for Orange and Rockland Utilities, Inc. The conclusion at that time was that the 2/3 and 1/3 weightings are consistent with the recommended decision in the Generic Finance case, that the concerns raised at that time are addressed by the two-stage DCF model employed by DPS Staff, and that the DCF method offers the significant benefit of reliance on readily available, objective data. In that same order, CPB continues, continuing concerns were expressed about the CAPM method, pointing out that

¹⁹¹ The Company's updated/revised DCF estimate is 12.7%.

¹⁹² CPB's BoE, pp. 7-10.

divestiture of generation should have reduced the riskiness of electric utilities in New York, but that betas of holding companies had gone up. The latter increase, according to that order, could reflect an increase in utility risk or an increase in risk because of holding company investments in non-utility businesses.

Citing the July 1994 recommended decision in the Generic Finance case that supported a convention of 2/3 weight to the DCF method and 1/3 weight to the CAPM method, and numerous decisions consistent with that recommendation in 14 subsequent years, the NYC Government Customers also except to the recommendation that the DCF and CAPM results be weighted equally. The fact that both methods involve some subjective judgment, the argument continues, is not a good reason to deviate from the preferred convention.¹⁹³

The Company opposes these three exceptions, arguing:¹⁹⁴

- a. While the approach recommended in 1994 in the Generic Finance case has been followed consistently, we should nevertheless be prepared to reassess that approach when presented with evidence suggesting modifications are needed to produce a fair rate of return.
- b. Current and projected volatility in capital markets alone justify reassessment of the Generic Finance case approach.
- c. There is evidence of deficiencies in the DCF, CAPM, and Risk Premium methods and that is why it is unreasonable to give more or less weight to any one method.

No good reason has been presented for us to conclude that the judges' recommendations on this issue rest in whole or in part on the Company's criticisms of the DCF method in instances when market-to-book ratios exceed one. Nevertheless,

¹⁹³ The NYC Government Customers' BoE, p. 25.

¹⁹⁴ The Company's BoE, pp. 47-48.

we are granting the exceptions of DPS Staff, CPB, and the NYC Government Customers.

As DPS Staff points out, the DCF relies on readily available data to make objective estimates of investors' return requirements.¹⁹⁵ While the DCF has one input of primary controversy (growth), two CAPM inputs (beta and the market risk premium) are dependent on estimates which are contested and volatile. Measures of beta have dropped from approximately .80 at the time of the recommended decision to .70 now (and dropping from .93 during Case 07-E-0523).¹⁹⁶ The market risk premium is also subject to great variability in short periods, changing from 8.1% at the time of the recommended decision to 10.0% currently. In fact, while we prefer a forward-looking market risk premium, the volatility of using just one, as DPS Staff does, raises concerns which should be addressed in future rate cases. For these reasons, we are according 2/3 weight to our DCF results and 1/3 weight to our average CAPM results, or 10.41% overall.

The Company presented a Risk Premium estimate of the cost of common equity. The judges rejected this approach, stating that it has not been shown to be relevant to the Company's level of risk.¹⁹⁷ We support this finding. As we have stated before, "the significant differences among utilities and among the ways that allowed returns are set by regulatory commissions render such comparisons unreliable, absent careful effort and analysis to ensure comparability."¹⁹⁸

¹⁹⁵ DPS Staff's BoE, p. 43.

¹⁹⁶ Case 07-E-0523, Consolidated Edison Company of New York, Inc. – Electric Rates, Exhibit 254.

¹⁹⁷ R.D., p. 225.

¹⁹⁸ Case 06-E-1433 and 06-E-1547, supra, Order Setting Permanent Rates, etc. (issued October 18, 2007), p. 14.

7. Credit Quality Adjustment

The judges agreed it makes sense intuitively that the market segment and business risks are the same whether one is interested in purchasing the Company's bonds or common stock. However, the Company had introduced an exhibit (Ex. 296) that it had claimed clearly establishes that there is no correlation between credit quality ratings and equity returns and no party had countered that claim in whole or in part. Taking this and some other information into account, the judges recommended a credit quality adjustment of 26.5 basis points, one half what DPS Staff had proposed to recognize that the Company's credit rating is higher than that of the proxy group.¹⁹⁹

The Company excepts, offering the following arguments:²⁰⁰

- a. There is no record evidence demonstrating any relationship between credit quality (S&P bond ratings) and market-equity returns estimated using the DCF and CAPM approaches.
- b. Page 1 of Ex. 296 examines the relationship between DPS Staff's DCF-derived equity returns and S&P bond ratings for the companies in DPS Staff's proxy group. It shows no credit quality adjustment is warranted.²⁰¹
- c. Page 2 of Ex. 296 examines the relationship between the beta component of the CAPM model and credit ratings and this shows no credit quality adjustment is warranted.²⁰²
- d. The judges' intuition is grounded in consideration of Generally Accepted Accounting Principles (GAAP) book results while the DCF and CAPM are market-derived analyses. Given the use of market-derived estimating techniques, the generally-accepted

¹⁹⁹ R.D., pp. 228-229.

²⁰⁰ The Company's BoE, pp. 40-42.

²⁰¹ Id., pp. 40-41. The Company explains this argument in some technical detail, offering information that was not offered in testimony during the hearings.

²⁰² An extra record explanation is again provided.

efficient market hypothesis overrules GAAP. That hypothesis holds that all information about a security, including the credit rating of a security's issuer, is incorporated into the price of the security.

- e. In the alternative, the magnitude of the recommended adjustment is excessive given that the supposed "BBB" companies in DPS Staff's proxy group are equally weighted in the Moody's "A" and "BBB" indices.²⁰³
- f. DPS Staff's willingness to reduce its proposed adjustment during briefing serves to underscore the adjustment's inherent unreasonableness.

DPS Staff opposes the Company's exception, arguing:²⁰⁴

- a. The Company's argument is undermined by the testimony of its own witness that "market prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities..." (Tr. 3131).
- b. Moody's and S&P regularly assess the risk of companies they rate and the Company's stronger credit rating means an investment in the Company is more secure and hence, less risky, than an investment in a portfolio of proxy group company stocks (Tr. 3353-54).
- c. We should ignore the Company's alternative argument, based on the existence of seven A-rated operating company subsidiaries of BBB-rated holding companies in DPS Staff's proposed proxy group. DPS Staff says there is nothing surprising about the fact that some operating companies have credit ratings higher than their holding Company parents because the parents tend to be more highly leveraged and have riskier non-regulated subsidiary operations.

For some of the same reasons just listed and for additional reasons that follow, DPS Staff also excepts to the judges' credit quality adjustment recommendations:²⁰⁵

²⁰³ This is a simple summary of an argument the judges expressly declined to adopt in the recommended decision because the Company's explanation was very hard to follow.

²⁰⁴ DPS Staff's BOE, pp. 29-30.

²⁰⁵ DPS Staff's BoE, pp. 46-49.

- a. The judges should not have recommended a reduced adjustment due to a lack of correlation between debt costs and historical equity returns. The Company's argument is false because there is no caveat in financial theory to the effect that prospective returns must recognize past relationships between debt costs and achieved returns.
- b. The 23.5% drop in the Dow Jones Utility Index from March 28, 2008 through January 20, 2009, and the increase in Consolidated Edison, Inc.'s share price from \$39.45 to \$39.50 during that time, confirms that the Company is considerably less risky than its utility peers.
- c. Given the turmoil in the financial markets and the disparity between current credit spreads and those that existed on average over the past 20 years, it would not be unreasonable to adopt a credit quality adjustment of between 21 and 53 basis points.

The Company replies:²⁰⁶

- a. Ex. 296 shows that DPS Staff's DCF-derived prospective returns are not correlated with the credit quality of the companies in DPS Staff's proxy group.
- b. DPS Staff again fails to produce any academic support for its position.

We are adopting a credit quality adjustment of .41% based on the recent five year average spreads between the Company's bond ratings and those of the proxy group.²⁰⁷ A seminal ratemaking principle is that allowed returns should be commensurate with risk. Bond ratings are a way to measure differences in risk. Investors recognize bond ratings as a basis for distinguishing higher or lower yields for debt. Equity is subordinate to debt, and it therefore follows that these risk differences would exist and be magnified for equity holders.

²⁰⁶ The Company's BOE, p. 49.

²⁰⁷ DPS Staff's updated adjustment as of February 2009 is 130 basis points using the same methodology as in DPS Staff's direct case.

The Company's' arguments to the effect that no credit quality adjustment is warranted are undermined by and contrary to the testimony of its own witnesses. One of its witnesses, for example, testified that "investors will differentiate between the risks they assume. For several years, investors have made relatively little distinction in the cost of capital, based on the risk of those entities. This willful ignorance of risk no longer exists and we can expect the aggressive distinction of risk to persist for a significant period."²⁰⁸ Another Company witness also testified that market prices of debt and equity capital are set by supply and demand, and both are influenced by the risk and return expected for their respective securities and the risks expected from the overall menu of available securities.²⁰⁹ The Company's exception is denied.

8. The Company's Revised Request for 10.6%

The Company now requests a 10.6% return on common equity, arguing:²¹⁰

- a. 10.6% is consistent with the judges' 10.58% return exclusive of any adjustment for credit quality and issuance costs.
- b. 10.6% is the amount reflected in the Company's update/correction filing in late December 2008.
- c. It is compelled to increase its request because it now seems likely that capital costs will remain higher given the poor economy, that credit markets will remain stressed and volatile, and as it must maintain access to needed capital on reasonable term.
- d. Some of the judges' expense and rate base adjustments would result in the disallowance of reasonable business costs and its proposal to ameliorate its rate filing, including the request

²⁰⁸ Tr. 1831-32.

²⁰⁹ Tr. 3131.

²¹⁰ The Company's BoE, pp. 38-40.

for a 10.0% return on equity, was expressly conditioned on their being no such disallowances.

DPS Staff replies as follows:²¹¹

- a. The Company is inconsistent to argue that capital costs have risen substantially while requesting 10.6% instead of the 11.0% supported in the Company's direct case.
- b. DPS Staff's updated 9.7% (as of December 2008) shows a 60 basis point increase since the 2008 Rate Order and a 20 basis point increase since its direct testimony was filed in early September 2008.
- c. Recent trades of 10-year debentures issued by the Company in December to yield 7.125% are now yielding only 5.7%, an indication that capital costs in the fixed-income market will not necessarily be higher throughout the Rate Year. Likewise, yields on the Company's most recent 30-year debt issuance decreased from 6.75% in April 2008 to approximately 6.0%.²¹²
- d. The indicated dividend yield requirements on Consolidated Edison, Inc.'s common stock is down from 5.9% in March 2008 to 5.8% as of February 3, 2009.
- e. While Value Line and Zacks were forecasting long-term growth of 4.5% and 3.2% when the Company filed its case, they now forecast growth of 1% and 2.1%, respectively.
- f. In sum, the financial turmoil has had dramatic, negative effects on many firms, but not on financially strong, low-risk companies like Consolidated Edison.
- g. The Company's recent debt issuance with an authorized equity return that is 60 basis points lower than the return now recommended by DPS Staff proves that the Company continues to have unfettered access to capital markets.
- h. The Company just announced its 35th consecutive annual common equity dividend increase. This is a strong indication that the Company's parent expects continued access to equity markets.

²¹¹ DPS Staff's BOE, pp. 25-29.

²¹² DPS Staff acknowledges that these comparisons do not reflect issuance premiums for any new debt.

- i. The judges did not create any increased risks for the Company as they recommended 97% of the \$654 million initially requested by the Company.
- j. The revenue requirement effect of the Company's 10.6% compared to DPS Staff's 9.7% is approximately \$103 million.

The County opposes the Company's exception for the following reasons:²¹³

- a. The Connecticut Department of Public Utility Control issued an order on February 4, 2009, rejecting a request by United Illuminating for a \$51.4 million revenue increase. Instead, it ordered a rate decrease based in part on a determination that 8.75% is a reasonable cost of equity.
- b. The Statement of Policy (referring to the Statement of Policy Concerning Evidence of Economic Impact in Rate Cases (issued January 14, 1980)) clearly recognizes that this Commission can reject any rate of return even if it conflicts with its usual practice of setting an allowed rate of return at the lowest level within a range of reasonableness.
- c. Lowering the return on equity to a more reasonable 9.0% properly balances the interests of shareholders and ratepayers and would be reasonable at this time.

Our overall equity return conclusions are based in part on our review of the Company's evidence and arguments in support of an 11.0% return on equity and need not be reevaluated in light of the recent change in the Company's request for a return of 10.6%.

Going beyond that fundamental point, the judges' recommendations to disallow certain costs on grounds that such costs are unreasonable or should not be borne by ratepayers do not constitute a reason on which we would rely to increase the allowed return on common equity. Rather, it is incumbent on the Company to avoid unreasonable costs or to bear full financial responsibility for its decision to do otherwise. Another factor ignored in the Company's recent request is that it is based in

²¹³ Westchester's BOE, pp. 4-7.

part on proposed methodological changes that went beyond the updates requested by the judges and, thus, is procedurally improper.

As noted above, there is uncertainty about the future in light of the recent economic downturn. Dealing with that uncertainty is a major consideration in these cases. The Company suggests it is a given that credit markets will remain stressed and volatile. For reasons discussed by DPS Staff and noted above, the Company's suggestion is inconsistent with some current information about trades in the secondary market and analysts' decreased estimates of growth. Turning, finally, to Westchester's arguments, that another utility in another state was recently awarded an 8.75% return on common equity says nothing about how we should decide this rate case. There has been no presentation concerning the comparability of the Company and United Illuminating. Likewise, the Statement of Policy on Economic Impacts discusses issues on which parties might file evidence but does not suggest how such issues ought to be resolved. The County's arguments are rejected.

9. ROE Conclusion

As discussed above, we are according 2/3 weight to our DCF result of 10.47% for the proxy group and 1/3 weight to our average CAPM results of 10.28% for the proxy group, or a weighted cost of equity for the proxy group of 10.41%.²¹⁴ This overall result is being adjusted downward by 41 basis points to reflect the credit quality difference between the Company and the median of the proxy group and increased by four basis points

²¹⁴ This unadjusted result is roughly equivalent to the average electric utility allowed ROE of 10.38% reported by Regulatory Research Associates for 2008 and the first quarter of 2009.

as recommended by the judges for issuance costs. The 10.04% result is rounded to 10.0%.²¹⁵

This return on equity, in conjunction with the 48% equity ratio and other risk-reducing provisions adopted here, should allow the Company to maintain its financial integrity, given that it matches what the Company claimed for most of these cases was needed to ensure access to capital on reasonable terms. It said we must, “. . . adopt an ROE of at least 10.0%, so as to preserve the Company’s “A” rating and permit it to raise common stock capital.”

10. Earnings Sharing Trigger and Cap

The judges recommended that we give serious consideration to an earnings sharing trigger and cap in light of several key factors. First, the Company has shown that for the current rate year it sees nothing wrong with asking for and receiving funds in rates to fill new positions, not filling a large number of those positions, and not establishing how the funds were used. Stated differently, the Company showed that it could increase its rate of return simply by not filling positions that it had claimed were needed to maintain reliable and otherwise reasonable electric service. Second, the judges concluded that earned rates of return in excess of allowed rates of return in past years likely contributed to the Company’s achievement of an “A-” credit rating. The judges thought that adoption of a Revenue Decoupling Mechanism in the Company’s last case decreased the chances the Company would be able to earn above its allowed rate of return in the future. Meanwhile, the judges noted that both the Company and DPS Staff proposed that this rate case be decided in a manner intended to ensure the Company’s maintenance of an “A-” credit rating. Third, the

²¹⁵ No RDM adjustment is proposed or is being made to the ROE since the risk reducing effects of the RDM are already reflected in the Company’s credit ratings.

judges thought it more difficult than usual to estimate what level of productivity the Company might reasonably be able to achieve in the Rate Year. Fourth, the judges thought that the current economic downturn is a unique circumstance that warrants protecting ratepayers against excessive utility earnings.

Taking all of these factors into account, the judges reasoned that an earnings sharing trigger and cap mechanism would give the Company some limited upside earnings potential--to help it retain its "A-" credit rating--while limiting the Company's ability to convert revenues intended to match expenses into rates of return in excess of what is allowed.²¹⁶

The Company excepts, offering the following arguments:²¹⁷

- a. The judges' recommendation introduces substantial regulatory risk and should not be adopted.
- b. No party made such a proposal and the cost of capital experts in these cases have not had an opportunity to make recommendations in the context of such a proposal.
- c. There is no basis in the record for assuming the Company will achieve productivity greater than 1% or \$10.6 million per year.
- d. While joint proposals frequently call for earnings sharing triggers and caps, this Commission has never adopted such a mechanism in the context of a one-year rate plan.²¹⁸
- e. Public Service Law (PSL) §66(20) authorizes refunds for over-earnings in a 12-month period only after the over-earnings occurs and only after there has been an opportunity to consider all of the relevant factors, including whether actual capital costs are higher than when last estimated.

²¹⁶ R.D., pp. 234-235 and 10-11.

²¹⁷ The Company's BoE, pp. 42-49.

²¹⁸ This is the same basic argument DPS Staff makes with respect to the reconciliation of property tax expenses, an argument with which the Company disagrees in that instance.

- f. No statute expressly authorizes the disposition of equity earnings in excess of those allowed except as provided in PSL §66(20).
- g. The judges did not adequately explain how earnings would be calculated. This is a further reason to conclude that PSL § 66(20) governs.
- h. Alternatively, the earnings sharing trigger should be 100 basis points above the allowed equity return, suggesting this is typical in cases with joint proposals.

The County opposes the Company's exception, arguing:²¹⁹

- a. The recommended sharing trigger and cap are reasonable.
- b. The effect of increasing the earnings sharing cap from 50 to 100 basis points above the allowed return is an extra \$60 million of earnings for shareholders, an amount it considers unnecessary.

No party responds to the Company's legal argument.

DPS Staff does not comment on the recommended earnings sharing trigger and cap.

As discussed elsewhere in this order, it is very important that the Company have strong incentives to operate efficiently given the electric rates we set. The recommended equity earnings sharing trigger and cap would minimize that incentive and we conclude this would be contrary to the interests of ratepayers in the short- and long-run. Furthermore, in the context of an RDM and downside true-ups for capital investment, an earnings sharing mechanism would not be balanced. Accordingly, the Company's exception is granted. However, we do not reach the questions of whether we lack statutory authority to adopt the judges' recommendation or whether such a mechanism must be proposed through the testimony of one or more parties before it could be adopted.

²¹⁹ Westchester's BOE, pp. 7-6

B. Cost of Debt

The judges noted the Company plans to issue at least \$1.1 billion of debt before the end of the Rate Year, in addition to \$600 million of 10-year debt issued in December 2008. (In fact, the Company issued \$750 million of additional debt on March 23, 2009.) The judges also discussed the agreement of the Company and DPS Staff that debt costs be updated at the time of our decision and recommended DPS Staff's approach for such an update. That forecast method calls for use of the latest Moody's determination of spreads above Treasuries for similarly-rated utility debt as well as a premium for new issuance. The judges also endorsed the agreement of the Company and DPS Staff that actual and forecast debt costs for the Rate Year should be trued up in light of market uncertainty.²²⁰

Using the latest debt yields including issuance costs, the updated Rate Year cost of long-term debt is 5.79% compared to the 5.96% reflected in the recommended decision. Appendix IV shows the derivation of the 5.79%.

For purposes of the reconciliation, Appendix IV will be replicated using actual data and determining the revenue requirement effect of the difference between what was authorized and incurred will be subject to true-up. It is solely the overall cost rate of debt which should be reconciled, and not the amount of debt outstanding. We note that such a true-up of debt costs in a one-year litigated rate case is unusual. However, given the special circumstances created by the upheaval in the financial markets recently, such a mechanism is warranted. In light of recent volatility, it is currently difficult to estimate accurately what auction rate debt costs and spreads to Treasuries will be in effect when the Company issues additional debt. This reconciliation protects both the

²²⁰ R.D., pp. 236-238.

Company and customers by removing the risk of a very inaccurate estimate of such costs.

C. Overall Rate of Return

Given the 10.00% updated cost of common equity, the 5.79% updated cost of long-term debt, the updated customer deposit rate of 4.85% (up from 3.75%) and the judges' uncontested capitalization ratio recommendations, the Company's overall allowed rate of return in the Rate Year is 7.79%, calculated as follows:

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
RATE OF RETURN REQUIRED FOR THE RATE YEAR
TWELVE MONTHS ENDING MARCH 31, 2010

PER COMMISSION			
	Average <u>Capitalization %</u>	Cost <u>Rate %</u>	Weighted <u>Cost Rate %</u>
	<u>Percent</u>		
Long Term Debt	49.60%	5.79%	2.87%
Preferred Stock	1.10%	5.34%	0.06%
Customer Deposits	1.30%	4.85%	0.06%
Common Equity	<u>48.00%</u>	10.00%	<u>4.80%</u>
Total	<u>100.00%</u>		<u>7.79%</u>

IX. RATE BASE

A. Lower Allowance for Infrastructure

1. Transmission and Distribution

a. Introduction

The Company initially forecast a transmission and distribution (T&D) capital budget of \$1.723 billion in 2009 and \$1.596 billion in 2010. The dollar impact of this investment on Rate Year plant in service has not been specified.

DPS Staff proposed a general downward adjustment to Rate Year plant in service of \$125.769 million and a related downward adjustment to Rate Year T&D expenses. The basic premise underlying these adjustments is that for many of the Company's capital programs and projects, the Company historically invested or expended fewer dollars than it had budgeted. On that basis, DPS Staff projects that the Company will do likewise in the Rate Year, meaning that rates based on the Company's T&D forecasts would be unnecessarily high. This is referred to as DPS Staff's historic spending adjustment.

DPS Staff also proposed adjustments to eight specific T&D programs or projects for reasons going beyond its historic spending adjustment. It proposed as well that the costs of two T&D projects or programs be considered in other cases.

The Company disagreed in large part with DPS Staff's proposed adjustments but accepted some, both at the hearings and in its trial briefs. In its initial trial brief, the Company also reported the results of its updated forecast of approximately \$1.623 billion T&D investment in 2009, or approximately \$100 million lower than its earlier forecast.

The judges recommended against adoption of DPS Staff's historic spending adjustment because the Company provided very extensive support for its planned expenditures. DPS Staff's adjustment, on the other hand, was premised solely on what the Company had invested or spent in the past years compared to Company budgets for those years and the judges concluded that approach would be a departure from the 1977 Statement of Policy on Test Periods in Major Rate Proceedings. Outside of the DPS Staff's specific adjustments discussed separately below, the judges noted, DPS Staff did not offer any substantive basis for questioning the Company's planned Rate Year T&D investment and

expenses.²²¹ Indeed, for some projects and programs, DPS Staff expressly agreed that the Company's plans were substantively reasonable. The judges also thought it unwise to adopt a low estimate of T&D investment given their separate recommendation to adopt DPS Staff's proposals that the revenue requirement effects of planned T&D and other capital investment reflected in rates but not actually made be deferred with interest for the future benefit of ratepayers.²²²

Turning to DPS Staff's proposed adjustments to specific projects or programs, the judges recommended adoption of three of DPS Staff's proposed specific adjustments, recommended outcomes between the two parties' positions for three issues, and recommended adoption of the Company's position on four issues.²²³

The judges made reference to some DPS Staff T&D adjustments that the Company agreed to during the hearings and initial briefs. However, only the former are reflected in the cost of service calculations attached to the recommended decision.

As to the \$100 million reduction in forecast 2009 T&D plant investment, the judges did not reflect it in their cost of service calculations, in small part because they did not believe they had enough detail or time for that change to be reflected in Rate Year plant in service and in large part because the referenced Policy Statement provides that updates of forecasts will be accepted only if they are provided up to the time that DPS Staff's direct case is cross-examined. The latter occurred in October 2008 and the update in the Company's initial trial brief was provided on November 21, 2008.

²²¹ R.D., pp. 265-266.

²²² Id., pp. 299-301.

²²³ Id., pp. 266-267.

The sections that follow pertain to: DPS Staff's historic spending adjustment; some of DPS Staff's issue-specific adjustments; the proper treatment of DPS Staff's adjustments accepted by the Company; and the Company's \$100 million T&D budget forecast update.

b. DPS Staff's Historic Spending Adjustment

For the reasons that follow, DPS Staff excepts to the recommendation against its historic spending adjustment:²²⁴

- a. DPS Staff's proposed T&D O&M adjustment is \$22.528 million, not \$40 million as reported by the judges.
- b. Historic cost analysis is a principal evaluation tool accepted for many years. Denying parties the opportunity to evaluate, draw conclusions, and advance recommendations based on historic performance seriously handicaps parties and imposes an unfair bias in favor of utilities.
- c. The judges are inconsistent to recommend DPS Staff's historic hiring practices adjustment while rejecting DPS Staff's historic spending adjustment for T&D capital and expense items.
- d. The Company under-spent its 2008 electric operations budget by over \$100 million and its 2008 common operations budget by \$49 million. The implication is that this is a further reason to believe that DPS Staff's historic spending adjustment is reasonable.
- e. The Policy Statement on Test Periods in Major Rate Proceedings holds that rate case forecasts must be developed from a historical base and that parties should be able to retrace a utility's projections to the historical base.
- f. The historic relationship between budgeted and actual expenditures provides a reasonable guide as to what the Company will likely spend in the future.
- g. Contrary to the judges' claim, DPS Staff's adjustments are not based solely on an analysis of historic costs. The record shows that DPS Staff investigated each capital and O&M project and program and that such review led to the proposed adjustments (Tr. 2998, 3003, and 3007).

²²⁴ DPS Staff's BoE, pp. 50-53.

- h. That DPS Staff agrees some projects and programs are needed is not decisive because the Company in past years invested or spent less than budgeted amounts even on projects or programs that were unquestionably needed.
- i. The Company admits it would be grossly unfair to ratepayers to pay rates based on projections of investments and expenses that are higher than actual. Adoption of the recommended decision will permit such a situation to exist.

Finally, in a separate part of its brief, DPS Staff argues that the effect of rejecting its historic expenditure adjustment is to shift the burden of proof from the Company to other parties.²²⁵

The Company opposes DPS Staff's exception for the following reasons:²²⁶

- a. The judges did not deny the parties the opportunity to evaluate, draw conclusions, and advance recommendations based on the Company's historic performance. They held that adjustments based solely on historic performance did not overcome the Company's extensive evidentiary presentation in support of its Rate Year programs and projects.
- b. The Statement of Policy on Test Periods in Major Rate Proceedings says that the goal of ratemaking is to ascertain revenues, expenses, and other conditions in the Rate Year and, to that end, that historic data, emerging actual results, and projected changes in operations and costs should be considered. DPS Staff's adjustment is based solely on historic data.
- c. Adjustments based solely on historic performance were rejected in the 2008 Rate Order because they did not account for prospective planning and the assessment of needs based on aging infrastructure and demand growth. DPS Staff's proposal suffers from the same problems.
- d. DPS Staff's adjustment is inconsistent with its urging the Company to be more aggressive and proactive in the replacement and upgrade of aging

²²⁵ DPS Staff's Boe, p. 3, including n. 4.

²²⁶ The Company's BOE, pp. 50-56.

infrastructure (Tr. 2996-97). The Company's projections account for this information.

- e. The record shows that the Company fully met its burden of proof in support of T&D investment and expenses.
- f. The \$100 million under run in 2008 electric operations capital expenditures was primarily attributable to long term projects not scheduled to be included in net plant in service until after the Rate Year. In any event, the associated revenue requirement is and would continue to be subject to reconciliation and this fully protects ratepayer interests.

We are adopting DPS Staff's historic spending adjustment. Consideration of historic information is clearly appropriate under the referenced Policy Statement. Such information establishes a pattern of under-spending by the Company compared to forecasts. Emerging actual information is also appropriately considered under the referenced Policy Statement and a \$100 million reduction in actual 2008 T&D capital spending reported post-recommended decision is consistent with the historic pattern underlying DPS Staff's proposal. The remaining question is whether DPS Staff or other parties must disagree with the Company's forecast on a program or project specific basis in order for us to determine whether the Company will continue to under-spend in the Rate Year. We conclude not, because the Company has generally under-spent even as to projects and programs as to which there is no question of need.

We cannot agree with the Company's argument that a generalized adjustment to estimated T&D expenditures, such as the historic spending adjustment urged by DPS Staff here, was rejected in the Company's last electric rate case. The Company's argument notwithstanding, the 2008 Rate Order recognized the potential validity of such an adjustment.²²⁷

²²⁷ The 2008 Rate Order, pp. 91-92.

Indeed, in that decision we adopted an adjustment based, at least in part, on a “slippage” analysis provided by DPS Staff, the same type of analysis presented here. While we also based our adjustment in the 2008 Rate Order on our need to restrict spending to mitigate rate increases, the Company is simply wrong to assert that the 2008 Rate Order rejected the use of a generalized adjustment to estimated T&D investment.

In reaching this conclusion, we agree with the judges that the precise basis for DPS Staff’s proposed adjustment is the comparison it made between budgeted and actual T&D investment amounts in past years. That utilities are required to forecast Rate Year revenue needs working off of an historic Test Year also has nothing to do with this issue. We agree with the judges, moreover, that the risk to ratepayers of over-forecasting the Company’s actual investment is not high in light of their recommended one-way downward only reconciliation.²²⁸ However, we are concerned about setting T&D construction targets too high and removing or minimizing the Company’s incentive to operate efficiently. For this reason, a lower investment estimate is warranted.²²⁹

c. DPS Staff’s Project- or Program-Specific Adjustments

(i) Emergent Transmission Reliability

The Company proposed to invest \$10 million per year in emergent transmission reliability. Based on the results of an annual review of transmission feeder operations, the money would be used to address reliability concerns for some transmission equipment before it fails. DPS Staff proposed that the entire

²²⁸ That reconciliation recommendation clearly distinguished DPS Staff’s proposal here and its separate historic hiring adjustment proposal.

²²⁹ We consider separately the issue of whether to reflect the \$100 million reduction in the Company’s forecast T&D investment.

\$10 million per year be disallowed. The judges recommended an annual allowance of \$2.9 million based on the Company's historic investment for this purpose.²³⁰

DPS Staff excepts, arguing an historic average is not appropriate as there is no historic pattern and there have been no such expenditures since 2004.²³¹ The Company should simply invest what it needs and the Company's actual costs could be evaluated for reasonableness after the fact and a prospective rate allowance, if appropriate, could be provided in a future case.

The Company replies that it spent \$8.8 million on emergent work in 2005 (Tr. 3806) and that DPS Staff has not addressed much less rebutted the transmission feeder reliability concerns that give rise to the planned 2009 investment.²³² The Company also argues that the absence of any expenditure after 2005 does not negate or trump the reliability concerns arising from recent feeder performance.

DPS Staff's exception is granted. Exhibit 169, p. 18, a discovery response prepared by the Company, shows no outlays in this category in the period 2004 through 2007 and this was pointed out in DPS Staff's trial briefs.²³³ To the extent the Company is arguing that specific work needs to be done in response to recent operational problems, this is not established by any of the evidence it cites. There is also an open question of fact about whether the \$8.8 million project the Company identifies was for emergent transmission reliability work or for work needed in another category. Any failure of proof in that regard is properly assigned to the Company.

²³⁰ R.D., pp. 248-250 and 267.

²³¹ DPS Staff's BoE, p. 56.

²³² The Company's BOE, p. 57.

²³³ DPS Staff's Initial Brief, p. 224.

(ii) Work Management Systems

The Company plans to begin a project in 2009 to develop a consolidated electric construction work management system. The projected investment is \$1.5 million in 2009, \$13.5 million in 2010, and the total projected cost is \$65.280 million through 2012. DPS Staff proposed to disallow \$6.5 million of the 2010 figure.²³⁴

The judges recommended against DPS Staff's adjustment on the grounds that its opinion of how soon this project needs to be completed amounted to improper micro-management of the Company.²³⁵

DPS Staff excepts, arguing that the judges' recommendation is not supported and is potentially harmful to the rate making process.²³⁶ Determining if and when certain investment is needed is a typical part of its function, according to DPS Staff. As its witness testified, DPS Staff says, its proposal would help to reduce impacts on customers while the existing work management system remains operational.

The Company opposes DPS Staff's exception, asserting that the 2008 Rate Order directed the Company to aggressively act to manage costs and prioritize projects to achieve the necessary improvements at the least possible cost to customers.²³⁷ Adopting DPS Staff's adjustment, it says, would delay the roll-out of the consolidated work management software platform for electric operations (i.e., distribution) from 2012 to 2016.

²³⁴ Contrary to the recommended decision, p. 264, DPS Staff proposed no adjustment to the \$1.5 million for 2009. Ex. 172, p. 7 of 8, near the bottom. The total project figure is shown in Ex. 70, p. 2.

²³⁵ R.D., pp. 268 and 269.

²³⁶ DPS Staff's BoE, p. 55.

²³⁷ The Company's BoE, pp. 56-57.

Our rate year revenue requirement is based in part on capital investment in this project of \$1.5 million in 2009 and \$7.0 million in 2010. We agree that this project should go forward. However, we are informed that a report based on an ongoing audit of the Company will touch on the Company's plans, the extent to which they are reasonable, and the extent to which cost offsets are likely.²³⁸ That report is expected to be provided in the coming months and we will address this issue further in the Company's next electric rate case.

d. Corrections and Updates

The Company advises that the recommended decision incorrectly failed to reflect three DPS Staff adjustments to capital expenditures programs that the Company accepted. The adjustments total \$.586 million in 2009 and again in 2010.²³⁹ In its brief opposing exceptions, the Company states that there are nine DPS Staff adjustments that were accepted by the Company that are not reflected in the recommended decision, including the three referenced above. The nine downward adjustments to planned capital expenditures total \$6.75 million in 2009 and \$3.75 million in 2010.²⁴⁰

These corrections are uncontested and are reflected in our revenue requirement determination.

As noted above, the judges did not reflect in their cost of service calculation a \$100 million dollar reduction in the Company's 2009 capital investment budget. The budget update was reported for the first time in the Company's initial trial brief, some details were provided much later, and the judges thought they did not have enough information or time to determine in early January 2009 how the updates might affect

²³⁸ This information was not available to or considered by the judges in the recommended decision.

²³⁹ The Company's BoE, p. 25.

²⁴⁰ The Company's BoE, p. 50, n. 47.

plant in service in the Rate Year.²⁴¹ Even if they had the requisite time and information, the judges recommended against reflecting the update unless we would be inclined to consider updates of forecasts that would tend to support a greater revenue increase.

DPS Staff excepts, arguing the \$100 million reduction is described in the Company's trial brief as a material known change in the Company's capital budget not a change in estimate as characterized in the recommended decision.²⁴² DPS Staff goes on to note that the Company under-spent its 2008 T&D budget by \$100 million and its 2008 common operations budget by \$49 million. This significant under-spending, according to DPS Staff, should also be recognized so that rates will not be set too high.

Taking these DPS Staff arguments in order, the Company notes that the Rate Year revenue requirement impact of the \$100 million T&D budget reduction for 2009 is about \$5 million. The Company also reports that the 2009 T&D budget has been further updated, reflecting another \$11 million reduction (for a total of \$111 million) but states that net plant in service in the Rate Year is not affected beyond the \$5 million just mentioned.

As to whether the updated projection should be reflected in the final decision, the Company opposes DPS Staff's proposal, arguing:²⁴³

- a. We should tread lightly with the use of new estimates other than those for which there is a consensus.

²⁴¹ R.D., p. 241.

²⁴² DPS Staff's BoE, p. 51.

²⁴³ The Company's BoE, pp. 58-59.

- b. Customers are already protected because the Company does not oppose continuation of the T&D net plant downward-only reconciliation.²⁴⁴
- c. If DPS Staff's proposal is adopted, this should be done subject to the caveat that in future proceedings, budget updates going the other way will also be reflected.

The Company opposes consideration of reductions in its actual 2008 investment for the following reasons:

- a. The Company report relied upon by DPS Staff and attached to DPS Staff's brief on exceptions is not part of the record. Erroneous conclusions might be drawn from this report and the Company would have no opportunity to respond.
- b. The impact on net plant in service in the Rate Year is \$6.5 million, reducing Rate Year revenue requirement by \$1.6 million.
- c. \$115 million of the under-run is related to the delayed in-service dates for the M-29 feeder and the York and Elmsford substations.
- d. DPS Staff's proposal does not account for the possibility that net plant investment from now through the end of the Rate Year may be higher than forecast.
- e. If DPS Staff's proposed update is reflected, it should be subject to the understanding that in a future proceeding where the Company's actual capital expenditures immediately before the Rate Year are higher than previously forecast, the higher actuals will likewise be reflected.

The Statement of Policy on Test Periods in Major Rate Proceedings (17 NY PSC 25-R, 28-R) states that revisions in known cost rates (such as for wage and tax increases), to the extent they are material, may be made as late as the Company's brief on exceptions. The stated reason for accepting changes this late is that they are easy for DPS Staff and other parties

²⁴⁴ The Company's decision to accept continuation of a downward-only T&D reconciliation, however, is expressly conditioned on our adopting the judges' T&D capital forecast for 2009 and 2010.

to verify and to note any disagreement in their briefs opposing exceptions. The referenced policy statement also discusses changes in estimates and states that they will be entertained when based on data not available at the time of the original filing and if presented not later than at the hearing at which DPS Staff's case is cross-examined or, in this instance, in mid-October 2008. We agree that an updated forecast would not typically be reflected at this time under the terms of the referenced policy statement. However, there is no objection by any party other than the Company. The information is also properly seen as Company-provided information requested at the hearings. Given that the new information reduces revenue requirement, moreover, reflecting the Company's own updated forecast is not likely to frustrate the ratepayer protection affected by the rate case process generally. Finally, we note we are also reflecting numerous cost updates that were provided after the briefs on exceptions, contrary to the express terms of the Statement of Policy on Test Periods in Major Rate Proceedings. The net effect of these is to increase substantially the Company's revenue requirement. In this context, it would not be fair to ignore the Company's updated T&D forecast.

As to the 2008 actuals, these comprise actual results that bridge the gap between the historical Test Year and the forecast Rate Year. The existing T&D reconciliation term addresses them for the current rate year, but not for the Rate Year at issue here and that is why they are properly reflected.

2. General Equipment

The Company's rate request is based in part on its projected investment in general equipment--vehicles, computers, lab equipment, furniture, tools, and communications equipment--of approximately \$77 and \$74 million in 2009 and 2010, respectively. The Company's May 2008 filing includes at least

two exhibits (Exs. 5 and 11) showing the planned monthly rate of investment but there was no testimony to support it. During the discovery process, DPS Staff asked the Company (DPS 318) for the location of any testimony in support and, if none, for an explanation of the forecast. The Company provided neither in a response that basically described the categories of general equipment and set forth the Company's projections for each by calendar year.²⁴⁵

DPS Staff filed testimony and exhibits in early September to the effect that the forecast investment should be disallowed as unsupported. It later became apparent that DPS Staff was also proposing a prospective disallowance of any return on general equipment acquired by the Company in the Linking Period of January 1, 2008 through March 31, 2009 (the period from the end of the historic Test Year, December 31, 2007, to the beginning of the Rate Year, April 1, 2009).²⁴⁶

The Company sought to augment its support for its forecast general equipment investment in the form of update/rebuttal testimony filed in late September 2008. A Company witness acknowledged on cross-examination that the further information was available in May 2008, when the Company's direct case was filed. DPS Staff moved to strike and the motion was granted in a ruling issued November 4, 2008.

In their trial briefs, DPS Staff continued to support a full disallowance and the Company sought the exact opposite.

In the recommended decision, the judges:²⁴⁷

1. Agreed in general that the overriding goal of ratemaking is to determine the Company's revenue needs in light of information presented timely and in a procedurally correct manner.

²⁴⁵ Ex. 190, pp. 61-66.

²⁴⁶ The 25-day extension of the suspension date, through April 30, 2009, does not change the Rate Year.

²⁴⁷ R.D., pp. 277-279.

2. Noted that there are prior decisions holding that DPS Staff and intervenors have an obligation to identify and invite a utility to flesh out those aspects of its rate filing that are deficient as a precondition to proposing a disallowance concerning those aspects.
3. Recommended for a variety of reasons that DPS Staff and intervenors be relieved of any such obligation on a prospective basis and that consideration be given to adopting specific filings standards that must be met before the 11-month suspension period would start to run. (The latter would require legislation).
4. Held that the minimum requirements set forth in the 1977 Statement of Policy on Test Periods in Major Rate Proceedings--the provision of testimony and exhibits justifying quantities, assumptions, expectations, activity changes, etc. (17 NYPSC 25-R, 26-R)--apply to general equipment.
5. Found that there is no conclusive record evidence about whether the Company provided the same level of proof for general equipment in past cases without any objection and concluded, in any event, that parties cannot waive the referenced Policy Statement.
6. Expressed mixed feelings about whether the Company's request for general equipment should be disallowed. While it was apparent to them that something needs to be done to ensure Consolidated Edison's future filings are more complete, the judges were concerned about disallowing all the planned investment in the absence of some proof that the Company does not need new vehicles, computers and the like to provide reasonable quality delivery service in the Rate Year. In other words, disallowing all planned general equipment investment might be counter-productive for ratepayers.
7. Recommended a disallowance of \$2 million of rate case expense as a deterrence and inclusion of the Company's forecast of general plant in rate base.

DPS Staff excepts, offering the following arguments:²⁴⁸

- a. The recommended decision is inconsistent to the extent it cites numerous procedural reasons why the Company's general plant forecast might be ignored and nevertheless recommends, aside from the recommended \$2 million rate case expense disallowance, that the Company's forecast for general equipment be reflected fully in rates.
- b. 16 NYCRR Part 61 places the burden of proof on the utility; there is no burden on DPS Staff to prove that the Company does not need general equipment in the Rate Year.
- c. There is no evidence in the record that the Company needs to purchase general equipment during the Rate Year.
- d. The approach taken by the Company denies DPS Staff and other parties the opportunity to test the need, timing and costs of the Company's planned investment in general equipment.

The Company opposes DPS Staff's exception, as follows:²⁴⁹

- a. DPS Staff does not dispute the judges' premise that the Company needs general equipment to provide safe and reliable delivery service in the Rate Year.
- b. As the judges expressly stated in the November 4, 2008 ruling, there is no shift in the burden of proof to DPS Staff and the other parties.
- c. In the Company's last electric rate case, a proposed CPB adjustment based on dissatisfaction with Company discovery responses was rejected on the grounds that CPB had failed to exhaust its remedies in the

²⁴⁸ DPS Staff's BoE, pp. 56-59. The reconciliation attached to DPS Staff's BOE shows a reversal of the recommended \$2 million rate case disallowance. The downward revenue requirement impact of granting its exception is estimated to be \$9.9 million for the Linking Period and \$3.4 million for the Rate Year. As discussed below, however, the Company estimates larger revenue requirement impacts of \$15.8 million for the Linking Period and \$4.9 million for the Rate Year. The Company's figures apparently include associated depreciation expense.

²⁴⁹ The Company's BOE, pp. 62-67.

discovery process (e.g., file a motion to compel a satisfactory response). The Company relied on this precedent and followed past practice and, thus, DPS Staff's draconian proposal is unwarranted, especially as there is no allegation that the Company did not stand ready to provide the additional information.

- d. Rate case proceedings should not be a game of "gotcha" and DPS Staff's approach for the general plant category differs from one it followed for other cost elements. The Company assumed its response to DPS Staff's discovery request DPS-318 was reasonable because DPS Staff did not object or ask any follow-up questions.
- e. DPS Staff provides no reason why the historic average spending should not be relied upon for a Rate year forecast. Exhibit 5, included in the Company's direct case, includes plant balances, amortization and depreciation, including for various categories of general plant on a monthly basis for the Linking Period and the Rate Year.
- f. There is other evidence on the record that supports the Company's projections for general equipment. Exhibit 344 shows historical costs by general equipment category for 2005, 2006, and 2007 and 2008 through August. That exhibit shows the 2005-2007 average investment was \$75.2 million per year, in line with the Company's forecast for 2009 through 2011.
- g. DPS Staff seeks to disallow a return on more than \$99 million of plant additions for general equipment in the Linking Period even though that investment was included in the Company's last rate case filing, was unopposed in its last case, and was reflected in part (January-March, 2008) in the 2005 Rate Plan. It makes no sense to disallow these costs, even prospectively, based on the Company's failure to re-justify them in testimony in these cases.
- h. DPS Staff is inconsistent to argue that the Company failed to meet current requirements and to propose on a prospective basis that the Company be required to prove the reasonableness of new costs in the Rate Year or deviations from the forecasts of more than 10%.²⁵⁰

²⁵⁰ The latter proposals are discussed below, in Section IX(B)(5) and (6).

- i. The effect of granting DPS Staff's exception would be to deny the Company \$4.9 million of revenue for planned Rate Year investment and \$15.8 million for its investment in the Linking Period. The Company says it is not clear if DPS Staff is pressing the latter point because it is silent on it. The Company provides the revenue requirement figure as a matter of caution.

The Company also excepts and appeals the November 4, 2008 ruling, arguing:²⁵¹

- a. The recommended \$2 million rate case expense disallowance is unreasonable to the extent it is based on a deficiency in one narrow aspect of the Company's rate case filing rather than on a comprehensive assessment of the Company's entire filing.
- b. A \$2 million disallowance is not needed to encourage the Company to meet the applicable rate case filing standards.
- c. Contrary to the recommended decision, the Company submitted sworn testimony to the effect that its approach in this case followed historical practice and that testimony is unchallenged (Tr. 404). It would be difficult or impossible to prove that other parties did not object to that approach in past cases.
- d. Even if parties cannot waive a standard by practice, it would be unreasonable to disallow \$2 million without prior notice, especially in light of the judges' tacit recognition that current filing requirements are general.
- e. While the judges recommend that DPS Staff and other parties be relieved prospectively of the obligation to identify and invite the Company to flesh out deficient aspects of its filing, past precedent holds otherwise and the Company relied in good faith on that precedent.
- f. DPS Staff and other parties should have some continuing obligation to avail themselves of all tools and remedies available for obtaining the information they need to evaluate a utility rate filing.

²⁵¹ The Company's BoE, pp. 50-52.

- g. Nothing in this case provides a basis for the judges' suggestion that consideration be given to starting the 11-month suspension clock only after it is determined that all filing requirements have been met.

DPS Staff disagrees with the Company as follows:²⁵²

- a. Parties are not collaterally estopped from questioning the level of support the Company provides for planned general equipment investment, merely because there was no objection in prior cases.
- b. DPS-318 asked the Company to identify where in testimony and exhibits it supported its general equipment request and to provide the justification for each project not included in the Company's filing. The Company's response (in Ex. 190) answered neither of these questions. The failure of proof here is entirely the Company's.

We conclude that DPS Staff's exception pertains to general equipment investment for the Linking Period and the Rate Year. This has been its position all along and nothing it says on exceptions suggests anything to the contrary.

Under 16 NYCRR 61.3(b)(1), the Company is required to establish by competent testimony the detailed cost of rendering service to which its proposed new rates, rules, and regulations are applicable. The Company did not comply with this requirement for general equipment. Likewise, the Statement of Policy on Test Periods in Major Rate Proceedings states the long-standing expectation that rate case filings will be accompanied by testimony and exhibits justifying quantities, assumptions, expectations, activity changes, etc.²⁵³ The Company did not comply with this policy to the extent it failed to file testimony timely.

The Company seeks relief from any adjustment on various grounds. It suggests, for example, that it was

²⁵² DPS Staff's BOE, pp. 30-31.

²⁵³ 17 NYPSC 25-R, 26-R (1977).

reasonable for it to conclude that its response to DPS-318 was acceptable in the absence of any objection or follow up discovery. This essentially amounts to an argument that responsibility for meeting rate case filing requirements should be shifted to other parties. Such an outcome is contrary to the express terms of the rule and policy discussed above and we reject it. Moreover, it is highly unlikely any person reviewing the Company's answer to DPS-318 would reasonably conclude that it is a complete and direct response to the specific questions asked. This confirms our conclusion.

At the same time, the purpose of a rate case filing is to help us to set rates for a future period. The bulk of DPS Staff's adjustment, however, would result in the disallowance of a return on investment in the Linking Period rather than in the Rate Year. The Company is also correct that its investment plans for the current rate year were reviewed in its last rate case with no disallowance. Following such an evaluation, a disallowance in these cases would only be warranted on some showing that the Company's actual investment was unreasonable. Moreover, an attachment to DPS Staff's brief on exceptions shows the Company's budget and actuals for general equipment of \$99.064 million and \$98.935 million through December 2008. This information also suggests a disallowance of all general equipment investment for the Linking Period would not be reasonable.

Taking all of the above into account, DPS Staff's exception is granted as to the Rate Year and denied as to the Linking Period. The recommended \$2 million rate case expense disallowance is not adopted.

The Company's appeal of the November 4, 2008 ruling is denied. The Company's arguments against a revenue requirement adjustment have no bearing on whether the Company's "rebuttal"

was actually untimely direct testimony and properly stricken on that basis.

3. Electric Production

The Company forecast capital expenditures of approximately \$39 million per year and DPS Staff proposed a downward adjustment of approximately \$5.5 million based on the Company's investment levels over the prior five years.²⁵⁴

The judges recommended that the revenue requirement impacts of the Company's forecast be reflected in rates, subject to a downward only reconciliation provision. Under the latter term, which had been proposed by DPS Staff, the revenue requirement impacts of any planned investments not made by the Company would be deferred with interest for the future benefit of customers. Given this recommendation, ratepayers will not be harmed and the Company will not benefit financially if the latter actually invests less than it forecasts.

Aside from this term, other reasons why the judges did not recommend DPS Staff's proposed \$5.5 million disallowance include:²⁵⁵

1. DPS Staff said the Company had recently invested more than \$40 million per year and that it had no reason to believe the Company would not continue to invest at current levels.
2. DPS Staff agreed the work proposed by the Company needs to be done but said it has doubts about the timing and costs for such work.
3. DPS Staff seemed to be requiring a level of proof in support of the Company's forecast that goes beyond that set forth in the 1977 Statement of Policy on Test Periods in Major Rate Proceedings. Meanwhile, the Company described how its estimates were prepared and said they were made in good faith.

²⁵⁴ DPS Staff called it \$5.428 million and the Company called it \$5.6 million.

²⁵⁵ R.D., pp. 282-283.

4. DPS Staff had not provided a direct response to the Company's contention that investment levels in two of the five years in DPS Staff's historic average were aberrational.²⁵⁶
5. The Company's actual investment in the last three years averaged \$43.3 million.²⁵⁷

DPS Staff excepts for the following reasons:²⁵⁸

- a. The judges mischaracterized DPS Staff's argument concerning the proposed use of a five-year instead of a seven-year historic average. DPS Staff rejected the seven-year average because the East River Repowering Project work was ongoing during those years.
- b. The judges gave inadequate weight to DPS Staff's contention that the Company provided little proof supporting its projections as the planned projects are still in the conceptual design and work-scope development phase.
- c. The judges give too much weight to the Company's unsupported and undocumented cost and timing estimates (as contrasted with need).
- d. Customers should not be expected to fund projects that may or may not be completed.

The Company opposes DPS Staff's exception, contending:²⁵⁹

- a. DPS Staff champions the exclusion of aberrational data as a reason for not using a seven-year forecast but has still not responded to the Company's contention that two of the five years in DPS Staff's

²⁵⁶ Id. In connection with the latter point, the judges characterized as "beneath DPS Staff" an argument that use of a five-year historic average is reasonable because DPS Staff could have but decided not to rely on a seven-year average that would have reflected electric production capital investment levels that were substantially lower than its five-year average. See DPS Staff's Initial Brief, p. 248.

²⁵⁷ Actual investment levels, 2003 through 2007, are \$16.4 million, \$20.6 million, \$48.9 million, \$36.8 million, and \$44.3 million.

²⁵⁸ DPS Staff's BoE, pp. 59-60.

²⁵⁹ The Company's BOE, pp. 67-68.

five-year historic average are aberrational because they immediately followed the East River Repowering Project and the retirement of Waterside.

- b. DPS Staff does not contest the judges' conclusion that the Company's presentation meets the standards of the 1977 Statement of Policy on Test Periods in Major Rate Proceedings.
- c. DPS Staff does not contest that the Company justified the need for the proposed work and that it has no reason to believe that the Company should not continue to invest at the level Consolidated Edison proposes.

The Company's planned generation investment in ten subcategories is set forth in reasonable detail in its direct testimony (Tr. 919-933) and in Exhibits 81 and 150, pp. 22-23. The best record evidence is that the Company's actual investment in 2003 and 2004 is aberrational and DPS Staff provides no explanation as to why such information should nevertheless be relied upon. DPS Staff's exception is also undermined to the extent it says it is not aware of any reason why the Company should not continue to invest at recent historic levels of more than \$40 million per year. We also disagree that the judges misunderstood or misrepresented DPS Staff's arguments about use of a five-year versus a seven-year average. As the judges' surmised, rejection of a seven-year average with four years of aberrational data does not render reasonable a five-year average based in part on two years of aberrational data. Finally, it seems clear that DPS Staff is envisioning the filing of detailed construction plans to support forecast rate base increases and neither our rules nor policy statements require this. DPS Staff's exception is denied.

4. Facilities – West 125th Street Property

The judges declined to offer any recommendation under this heading, noting that the issues changed during the case and that the parties' trial arguments basically amounted to new proposals with no clear explanation by either side about why its

latest proposal is reasonable.²⁶⁰ The arguments offered at this point, accordingly, are more in the nature of clarified trial arguments rather than exceptions.

The basic facts are that the Company proposed to transfer a property at West 125th Street for \$15.3 million so that the building there can be torn down and a new charter school can be erected.

There was broad public support for the property transfer and, as discussed below, the transfer was previously authorized subject to conditions. In the present case, the Company proposes that it be authorized to true-up (be made whole for) any additional costs it incurs for leases, renovation, and moving into a replacement facility.

According to DPS Staff, the Company's proposed true-up is inconsistent with a prior decision in another case concerning the accounting for a net gain expected to result from the sale of the 125th Street Property,²⁶¹ would eliminate any incentive by the Company to control capital spending associated with a replacement facility, and is not warranted as the total annual revenue requirement impact of the replacement facility (compared to what is in rates today) would be about \$225,000 less some avoided costs. DPS Staff describes this as de minimis for a utility the size of Consolidated Edison.²⁶²

The Company argues that its true-up proposal would ensure that ratepayers pay no more and no less than the Company's actual incremental costs, if any, resulting from the sale of the West 125th Street property, regardless of the timing

²⁶⁰ R.D., p. 287.

²⁶¹ Case 08-M-0930, Consolidated Edison and Village Academies Network, Inc. – Transfer of 125th Street Property, Order Approving Property Transfer (issued October 28, 2008) (the October 28, 2008 Order).

²⁶² DPS Staff's BoE, pp. 60-62.

of the closing on that sale.²⁶³ Anticipating DPS Staff's arguments, the Company also argues there is no way to know whether the incremental costs to the Company will be de minimis as the exact date of closing is not known. If the impacts are de minimis, it continues, this undermines DPS Staff's contention that a reconciliation would eliminate any incentive to mitigate or control costs. DPS Staff's proposal to deny any incremental costs regardless of the Company's mitigation efforts, the Company continues, would provide the Company a disincentive to accelerate a closing on the sale should circumstances ever make such an acceleration possible. The Company also points out that all parties would have an opportunity to review the reasonableness of its incremental costs in the Company's next electric rate case, before the costs would be reflected in rates.

In response to DPS Staff's latest arguments, the Company adds that its true-up proposal was set forth in its affidavit in Case 08-M-0930 and that this proposal was not addressed much less rejected in the October 28, 2008 Order. Accordingly, it sees no inconsistency between its proposal and that order.²⁶⁴

In response to the Company's further initial arguments, DPS Staff argues that adoption of the Company's true-up proposal would mean that the benefits of the transaction might be fewer than those calculated in the net present value analysis performed to determine whether the proposed transfer is

²⁶³ The Company's BoE, pp. 53-55.

²⁶⁴ The Company's BOE, pp. 68-69.

in the public interest.²⁶⁵ It reiterates that the impact of any incremental costs are likely to be de minimis as the in-service date for the replacement facility is likely to be close to the end of the Rate Year. DPS Staff describes as counter-intuitive the Company's contention that denial of a true-up would give it a disincentive to accelerate a closing, saying that information presented in the case in which the transfer was authorized suggests the transfer date is dependent on the buyer.

In light of the positive net present value of the benefits of this sale of land estimated when the sale was authorized, and in light of the positive benefits of this transfer to the local community, the Company's proposal is adopted. There is nothing in the October 28, 2008 Order to the contrary.

B. Capital Expenditure Cap/Reconciliation and Capital Expenditure Reporting/Rate Case Demonstration

1. Introduction

DPS Staff proposed a continuation of the one-way downward-only reconciliation of T&D plant that was adopted in the 2008 Rate Order.²⁶⁶ The judges recommended adoption of DPS Staff's proposal.²⁶⁷ As a matter of principle, the Company continues to oppose such a term for T&D plant. However, it does not except to minimize the number of issues in controversy and as the judges recommended that the net plant target be set based

²⁶⁵ That analysis, says DPS Staff, suggested the sale would produce marginal quantifiable benefits to ratepayers. The October 28, 2008 Order, p. 18, anticipated a net present value benefit to customers of \$1.3 to \$3.2 million over 25 years. These are exclusive of other, unquantified benefits to the Harlem community.

²⁶⁶ The 2008 Rate Order, pp. 98-99. Any credit due ratepayers would be measured by the revenue requirement effect of any reduction in T&D plant in service from the level authorized in the 2008 Rate Order.

²⁶⁷ R.D., p. 299.

on the Company's forecast (and not based on any historic level of investment or any global adjustment).²⁶⁸

DPS Staff also proposed that the downward-only reconciliation adopted in the 2008 Rate Order for T&D plant be extended in these cases to several other categories of capital investment. The judges recommended adoption of DPS Staff's proposal and the Company excepts.

DPS Staff proposed a change in the existing downward-only reconciliation mechanism to exclude the effects of the cost of removal. The judges recommended against DPS Staff's proposal and DPS Staff excepts.

Finally, DPS Staff proposed new reporting and rate case filing requirements. The judges recommended against DPS Staff's proposals or that they be pared back and DPS Staff excepts on both counts.

The exceptions are discussed in turn.

2. Expansion of the One-Way Reconciliation

The judges recommended DPS Staff's proposal that the existing one-way, downward-only T&D reconciliation proposal apply as well to Electric Production, Shared Services, and Municipal Infrastructure capital expenditures. They reasoned as follows:²⁶⁹

1. The Company sought and obtained funding in its last electric rate case for numerous positions of which many were not filled in the current rate year. With the exception of one Company witness, the Company claimed there was nothing wrong with this approach. Setting rates with no reconciliation of actual and forecast capital expenditures, as the Company had proposed, would permit the Company to under-invest as a means to help drive up its earnings at the expense of reliability.

²⁶⁸ The Company's BoE, p. 56. However, the judges recommended some adjustments to the Company's forecast.

²⁶⁹ R.D., pp. 299-301.

2. Bilateral reconciliation of projected and actual costs would reduce the Company's incentive to minimize its capital expenditures.
3. The combination of a one-way, downward-only reconciliation term and a low estimate of Company investment, as DPS Staff proposed, would unreasonably increase the risk that the Company would not have sufficient revenues to cover its actual costs.
4. Accordingly, the best approach would be to adopt a reasonable estimate of the Company's capital investment, to leave in place the same incentives the Company has to control its capital costs, and to provide for a one-way, downward-only reconciliation.

The Company excepts, offering the following arguments:²⁷⁰

- a. The only reason the judges offer for their recommendation is to hold ratepayers harmless when the Company invests less than forecast.
- b. The effect of the recommendation is that the Company loses flexibility, once rates are set, to use funds to meet the needs that turn out to be the most important during the Rate Year.
- c. The Company also needs flexibility in order for it to earn its allowed rate of return and to achieve and retain the productivity that the recommended decision encourages it to pursue.
- d. The Company also excepts if the judges are recommending reconciliation of forecast and actual total capital expenditures. Such an approach would give the Company more flexibility to shift funds around, compared to a number of separate reconciliation mechanisms, but there is no basis in the record for it either as there is no demonstration that ratepayers would be harmed without such a term.

As an aside, the Company states that it currently includes capital expenditures for electric municipal infrastructure in the T&D reconciliation mechanism and that it proposes that this continue.

²⁷⁰ The Company's BoE, pp. 55-58.

DPS Staff opposes the Company's exception for the following reasons:²⁷¹

- a. Reasons for the judges' recommendation not discussed in the Company's exception include (1) concern about the Company under-investing to drive up its rate of return, and (2) the judges' contemporaneous support of a capital investment forecast much closer to the Company's than to DPS Staff's, in order to minimize the chances of a Company shortfall.
- b. The costs of copper, rolled steel, and synthetic rubber have gone down because of the economic downturn and the savings should be captured for ratepayers.
- c. A downward-only reconciliation for all plant categories is more important than ever in light of the recent arrest of ten Company employees.

The County agrees in part with DPS Staff and contends:²⁷²

- a. The judges properly recommended a downward-only reconciliation term for additional plant categories, so the Company will not shift such funds for T&D use or retain the associated revenues for shareholders.
- b. However, to allow the Company greater flexibility to shift funds from one category to another, the County supports adoption of one overall capitalized plant target that would be subject to a downward-only reconciliation.

There is some confusion on the record about whether DPS Staff is proposing one large reconciliation mechanism (with two minor exceptions discussed separately in the next subsection) or one reconciliation mechanism each for T&D, Electric Production, Shared Services, and Municipal Infrastructure capital expenditures.²⁷³ The Company understood

²⁷¹ DPS Staff's BOE, pp. 34-35.

²⁷² Westchester's BOE, pp. 8-9.

²⁷³ See Tr. 2463, 2523, 2554-55, 2824 and 3047 and DPS Staff's Initial Trial Brief, p. 255.

DPS Staff to be proposing separate mechanisms and we are evaluating the proposal on that basis.

With two minor exceptions noted above and discussed below, we are adopting four separate downward-only reconciliation mechanisms for the capital investment categories listed above. Such mechanisms will provide the Company a strong incentive to budget carefully, manage its capital operations efficiently, and keep total investment below the targets we adopt, with the possible exception of any incremental investment that is absolutely essential to the maintenance of safe and adequate electric delivery service.

We acknowledge that adoption of targets without any reconciliation would provide the Company even more incentive to operate efficiently. However, the record in this case with respect to the Company's historic hiring practices--i.e., numerous funded positions were not filled, with no solid evidence from the Company of how the funds were used instead--is a good reason to question whether the Company would increase earnings by becoming more efficient or seek to do so by pocketing carrying costs on investments not made. The Company's exception is denied.

3. Advanced Technology and Storm Hardening and Response True-Up Proposals

As summarized in Appendix 2, p. 2 of the recommended decision, the Company originally projected investment of approximately \$13 million and \$12 million in 2009 and 2010, respectively, in storm hardening and response. This investment would be for sectionalizing overhead distribution feeders to minimize outage impacts, installing automated switches and remote monitoring and control equipment, and replacing obsolete cable.

It likewise originally projected approximately \$49 million and \$39 million in 2009 and 2010, respectively, in

advanced technology. This would be for updates to its energy management system, and to enhance its work management system, as well as for cyber security and 20 separate investments in advanced technologies to create a "smart grid."

In its trial briefs, DPS Staff proposed that the Company be required to defer for the future benefit of customers the carrying charges on planned investment in these two categories that for any reason is not made during the Rate Year.

The judges did not recommend DPS Staff's proposal, citing the absence of any explanation of why these categories should be subject to separate downward reconciliations, outside that proposed and supported by DPS Staff for T&D, electric generation, shared services, and municipal infrastructure support capital programs and projects.²⁷⁴

DPS Staff excepts, arguing that it had provided an explanation, i.e., to encourage the Company to invest properly in these categories which can help reduce the likelihood of events like the Long Island City network and Westchester storm outages of 2006.²⁷⁵ It asks that separate, one-way downward-only reconciliation terms be adopted for these two categories of capital investment.

The Company does not respond to this exception specifically. As discussed immediately above, however, the Company expresses concern about losing flexibility to move funds from one capital investment category to another when warranted by operating circumstances, particularly as the number of separate capital investment categories subject to one-way, downward-only reconciliation goes up.²⁷⁶

²⁷⁴ R.D., p. 318. An issue about reconciling municipal infrastructure support O&M expenses is discussed above, in Section V(B).

²⁷⁵ DPS Staff's BoE, pp. 54-55.

²⁷⁶ The Company's BoE, p. 57.

We do not accept the underlying premise that the Company's investments in Storm Hardening and Advanced Technology affecting the Rate Year are so much more important than other T&D investment categories to warrant separate reconciliation terms. DPS Staff's exception is denied.

4. The Cost of Removal

As noted above, DPS Staff proposed a change in the current one-way, downward-only reconciliation approach so that it would isolate the net changes in the book cost of plant and exclude the effects of the associated cost of removing existing plant from service. The Company opposed DPS Staff's proposal.

The judges recommended against DPS Staff's proposal, noting that the actual cost of removal could differ from a forecast just as much as the cost of materials and equipment and that DPS had given no reason as to why the differences of one should be reconciled while the other would not.²⁷⁷

DPS Staff excepts for the following reasons:²⁷⁸

- a. A failure to isolate the costs of removal provides the Company with an upward reconciliation of the cost of removal i.e., it permits the Company to spend more than forecast for removal with no loss of income in instances where the associated net plant costs are lower than forecast.
- b. DPS Staff's proposal ensures that the benefits of under-spending on capital projects and programs are captured for the benefit of ratepayers.

The Company replies in opposition as follows:²⁷⁹

- a. The effect of DPS Staff's proposal is that the Company is penalized if its mix of capitalized plant and removal costs changes, in instances when the net plant component is lower than forecast, even if the total is exactly the same as the Company forecasts.

²⁷⁷ R.D., p. 303.

²⁷⁸ DPS Staff's BoE, pp. 63-64.

²⁷⁹ The Company's BoE, pp. 71-72.

- b. DPS Staff is inconsistent to press this exception even though it previously agreed²⁸⁰ that adoption of its proposal would result in an under-run of net plant worth \$201.862 million, in circumstances when the Company did not have any variance in the level of capitalized plant and removal costs.

Approximately 15% of total projected capital investment comprises removal costs. The latter costs are spiraling and the Company should have an incentive to keep them to the minimum necessary. Rejection of DPS Staff's proposal would have the opposite effect, however, providing the Company a disincentive to control removal costs should the actual for the other 85% of total projected capital costs be less than the projection we adopt. DPS Staff's exception is granted.

5. Proposed Reporting Requirements

DPS Staff proposed that the Company be required to prepare and file quarterly reports on its capital expenditures. The reports would include detailed explanations of actual investments by program or project that differ by 10% or more from the projected amounts reflected in rates, that involve programs or projects beyond those reflected in rates, or that involve projects or programs that have been abandoned or materially altered. The Company opposed DPS Staff's proposal.

The judges recommended that DPS Staff's proposal be rejected or pared back, observing that the Company does not prepare a quarterly capital investment forecast that could be used for comparison purposes and that it does not seem reasonable to require the Company to report quarterly deviations between forecasts and actuals that should be expected to be different. The proposal would also result in reports on very small dollar amounts. Finally, the judges noted that the proposed quarterly filing requirements would be redundant if DPS Staff's proposed new rate case filing requirements were adopted.

²⁸⁰ DPS Staff's Initial Brief, p. 259.

The Company already prepares Monthly Capital Budget Status Reports and the judges recommended that these be provided to DPS Staff.²⁸¹

DPS Staff excepts to the judges' recommendations, implying that the reports are critical to the proposed new rate case filing requirements on which it focuses.²⁸²

The Company responds, stating that DPS Staff has not addressed the judges' reasoning and that DPS Staff's exception should be given no weight.²⁸³

DPS Staff is clearly entitled under law to whatever information it needs to monitor utility operations and it needs no order from us to exercise its authority. That said, the judges correctly identified a number of practical shortcomings in DPS Staff's proposal and DPS Staff does not contest those reasons expressly. DPS Staff's exception is denied.

6. Proposed Rate Case Filing Requirements

DPS Staff proposes that the Company be required to file in its next electric rate case information similar to that to be provided in the quarterly reports just discussed, along with testimony that includes a complete justification of the then-current book cost of plant.

The judges expressed mixed feelings about DPS Staff's proposal. They agreed with DPS Staff, for example, that it is important to be sure that the Company's construction program is limited to what cannot be avoided, that work is completed efficiently, and that actual costs incurred are reasonable for the work done. They simultaneously expressed wariness of

²⁸¹ R.D., pp. 301-302. As to the proposed reports covering relatively small dollar amounts, see exhibits 47, 49, 51 and 54 (as filed in May 2008) and 310, 312, and 313 (as filed in late September 2008).

²⁸² DPS Staff's BoE, pp. 62-63.

²⁸³ The Company's BOE, p. 69.

adopting new rate case filing requests for the Company alone that might be perceived by investors as an increase in regulatory risk.²⁸⁴ In the end, however, the judges recommended against DPS Staff's proposal because they were concerned about the process and resource implications of overlaying on an already complex, 11-month Consolidated Edison electric rate case what amounts to a prudence proceeding concerning past Company investments. In this light, they suggested alternative approaches to address DPS Staff's valid concern, one of which would be to institute a separate prudence investigation. Finally, the judges noted that should we adopt DPS Staff's proposal, it should be recognized that very little actual information about the Company's capital investments in the Rate Year will be available by the time the Company files its next electric rate case (expected in May 2009).

As noted above, DPS Staff excepts offering the following arguments:²⁸⁵

- a. The judges' recommendation is disturbing because the proposed information is necessary for it and this Commission to determine if the Company's net book plant is reasonable.
- b. Investors' expected risk should not change because rate base expansion is always subject to review.
- c. The judges fail to recognize that the Company cannot reasonably request rate relief without explaining the reasons for new plant added beyond that previously proposed.
- d. It is inconceivable how the judges could conclude that DPS Staff's proposal would be too expensive, stating there is no evidentiary basis for such a

²⁸⁴ R.D., pp. 302-303. It is undisputed that witnesses for both the Company and DPS Staff testified that we should act in a manner intended to help ensure an S&P credit rating of "A-" could be maintained by the Company. One reason for doing so is minimize future capital costs and revenue requirements.

²⁸⁵ DPS Staff's BoE, pp. 62-63.

conclusion and that the costs of not adopting its proposal could be even greater.

The Company replies as follows:²⁸⁶

- a. DPS Staff ignores the investment community's acknowledged focus on consistency of regulation as a primary factor in rating utilities. To suggest that investors' risk would not be materially changed by DPS Staff's proposal ignores reality. Indeed S&P states that regulation of a delivery company could account for 30-40% of a business profile score.
- b. As suggested in the recommended decision, DPS Staff's proposal goes beyond what is required by the Statement of Policy on Test Periods in Major Rate Proceedings and 16 NYCRR Part 61, concerning rate case filings.
- c. DPS Staff's concerns can reasonably be addressed on a cost-effective basis without adopting DPS Staff's proposal.

The basic issue presented is how, if at all, should the rate case process be changed to focus not only on a utility's revenues, costs, and other variables in a future rate year but on the reasonableness of a utility's investments in plant for an historic period. Given that our rate decisions are not prudence determinations with respect to planned future investment and the relatively larger dollar amount of plant investment made by New York utilities each year, there should be no question about whether utilities' past investments are properly subject to review by the Department.

Going beyond the broader issue, DPS Staff is proposing a specific manner by which we would review the reasonableness of the Company's past investment in plant, in the context of future rate cases.

As the judges observe, however, there are some practical problems with DPS Staff's specific proposal, including the time constraints of the statutory 11-month rate case

²⁸⁶ The Company's BOE, pp. 70-71.

schedule, marshalling resources to complete the necessary work, identification of the past period of investments to be reviewed, and development of a process by which all the information necessary would be provided and reviewed. For these reasons, we decline to adopt DPS Staff's proposal.

C. EB Cap Adjustment

An earnings base/capitalization (EB Cap) adjustment was first adopted in 1975 because the Commission thought it improper for a utility to earn a return on a rate base that exceeded the utility's capitalization. The adjustment has been commonplace since that time, including in cases, such as the present one, in which a utility's capitalization exceeds its rate base.

The New York Power Authority opposed application of such an adjustment in this case, noting the effect is to increase the Company's rate base by \$388 million.²⁸⁷ The judges agreed with NYPA that the Company's explanation of need for the adjustment—use of the Federal Energy Regulatory Commission (FERC) formula for cash working capital and some point about pension credits—was fairly vague. However, the Judges declined to recommend NYPA's position in the absence of any support by DPS Staff.²⁸⁸

NYPA excepts, arguing the Company has the burden of proof, that the Company's explanation is so sparse that the judges could not even determine if it is reasonable, and, thus, that the judges have improperly presumed that the EB Cap adjustment is reasonable. NYPA goes on to fault the judges for giving undue preference to the view of one party (DPS Staff) and

²⁸⁷ As discussed below, the correct figure is approximately \$193 million.

²⁸⁸ R.D., p. 305. As of the conclusion of the hearings, the annual revenue requirement effect of adopting NYPA's proposal was estimated to be a \$22.3 million decrease.

for unreasonably shifting the burden of proof to DPS Staff. The end result, says NYPA, is that the Company is rewarded at the expense of ratepayers. In sum, according to NYPA, the EB Cap adjustment should be rejected based on the Company's failure to justify it.²⁸⁹

The Company replies that adoption of an EB Cap adjustment in the 2008 Rate Order is a legal basis for doing so here. Unlike other components of rate base that are forecast, the Company continues, the EB Cap figure is derived using actual data from the Test Year ending December 31, 2007 and a calculation method that is consistent with well-established precedent. The Company emphasizes that DPS Staff reviewed the Company's calculations and has no objections. According to the Company, therefore, it fully met its burden of proof and provided an adequate explanation of the EB Cap adjustment. Thus, it concludes, there is no improper shift in the burden of proof.

No other party comments on this issue.

The record shows that the Company's historic Test Year EB Cap adjustment was approximately \$388 million, but that the Company adjusted this amount downward by \$141.980 million.²⁹⁰ The latter figure was reduced to \$200.846 million in the Company's informal update in July 2008. It is that latter figure that DPS Staff supported, subject to a correction, bringing the figure to \$192.957 million.²⁹¹ In this context arguments about \$388 million are misplaced.

In this case, the EB Cap adjustment primarily corrects for differences between the Company's cash working capital requirements and those we forecast using the FERC formula (discussed next). The adjustment also reflects that non-cash

²⁸⁹ NYPA's BoE, pp. 2-4.

²⁹⁰ Tr. 2171-72 and Ex. 9, Schedule 5.

²⁹¹ Tr. 2757-2758.

pension credits have been employed in past cases to reduce delivery service revenue requirement. This requires the Company to finance the amount of the credits and this is reflected in rate base through a positive EB Cap adjustment.

We have also evaluated the Company's latest figure in comparison with the EB Cap adjustment adopted in the Company's last case and note that the results are very similar.²⁹² This confirms the reasonableness of the result here.

Given the specific record evidence in support of the EB Cap adjustment and the other reasons just mentioned, the EB Cap adjustment is reasonable and NYPA's exception is denied.

D. Working Capital - Lead-Lag Study

A portion of the capital invested in the Company is necessary because there are time differences between (1) the provision of service by the Company and its receipt of payment and (2) the Company's receipt of materials and services and its payment for them. Capital used in this way is referred to as cash working capital and is included in rate base so that the Company earns a return on or recovers the costs of such capital. This Commission has long-employed the FERC formula which equates cash working capital requirements with 1/8 of certain O&M expense. In this case, that formula yields \$185.6 million in rate base.

NYPA argued that the Company should be required to prepare a lead-lag study to determine more accurately the Company's cash working capital requirements. Pending completion of that study, NYPA proposed a \$19.4 million downward adjustment to the Company's cash working capital figure, based on the results of a simplified lead-lag study NYPA had prepared. NYPA also proposed that the Company be required to perform a

²⁹² The figure was \$184.509 million. The 2008 Rate Order, Appendix 2, Schedule A, p. 6 of 8.

retrospective lead-lag study to show whether use of the FERC formula resulted in an excessive Company rate base in past periods. Consolidated Edison opposed all of NYPA's proposals.

The judges agreed with the Company that prior decisions make clear this Commission's preference for use of the FERC formula because it is easy to use. They agreed with NYPA that use of the FERC formula may systematically overestimate the Company's cash working capital needs. However, the judges said they saw no purpose in requiring a lead-lag study in the absence of any willingness on our part to abandon the EB Cap adjustment. As noted above, the latter adjustment offsets any error in estimating cash working capital. As such an outcome seemed unlikely, the judges did not recommend any of NYPA's cash working capital proposals.²⁹³

For several reasons, NYPA strongly disagrees with the judges' pre-supposition of how we might resolve the EB Cap issue as a basis for rejecting NYPA's cash working capital proposals.²⁹⁴ To begin, this recommendation ignores the judges' finding that the FERC formula could very well systematically over-estimate the Company's cash working capital requirements. Second, one purpose of a recommended decision is to provide guidance to an agency in reviewing and implementing policy, deciding whether policy changes are needed, and, if so, in what areas and to what extent.²⁹⁵ Further exacerbating the judges' flawed reasoning, NYPA continues, is that whether an EB Cap adjustment is proper is also at issue and the judges found inadequate on even a gross basis the Company's explanation of why that adjustment is reasonable.

²⁹³ R.D., p. 309.

²⁹⁴ NYPA's BoE, pp. 4-7.

²⁹⁵ Id., p. 5. NYPA cites to the 2002 Manual for Administrative Judges and Hearing Officers, p. 135, posted on the Department of Civil Service web page.

Another problem with the judges' cash working capital recommendations, according to NYPA, is that they intertwine and overstate the relationship between cash working capital and the EB Cap adjustment. NYPA concludes, arguing that the Company's cash working capital requirements should be determined on a stand-alone basis and not based on conjecture about how the EB Cap issue might be resolved.

Consolidated Edison opposes NYPA's exception.²⁹⁶ It argues that this Commission has consistently expressed a strong preference for use of the FERC formula since the 1970s because the alternative of preparing lead-lag studies is so cumbersome and time-consuming and that NYPA's proposals in this case were rejected for failing to overcome this long-standing preference with evidence or arguments. According to the Company, this Commission has also required utilities to include EB Cap adjustments in their filings to correct for any over- or under-statement of working capital requirements that might result from using the FERC formula.

The Company goes on to criticize NYPA's failure to prove that any technological improvements since the 1970s (including computers) will translate into an increase in accuracy that justifies the time and expense of performing a lead-lag study.

Contrary to NYPA's argument, the Company maintains that the judges' recommendations rest less on how the EB Cap issue might be resolved and more on the fact that the mere possibility that the FERC formula may result in a systematic overestimation of cash working capital requirements does not overcome the long-standing preference.

There is no risk to ratepayers of overpaying for cash working capital requirements if the FERC cash working capital

²⁹⁶ The Company's BOE, pp. 74-76.

formula and the EB Cap adjustment are both employed. For this reason, there is no need for the studies NYPA proposes. While it is true that it may be easier to prepare such studies now, compared to thirty or more years ago, there is no reason to believe there would be fewer disputes about the proper inputs to such studies. Given the continued use of an EB cap adjustment, this could not provide any benefit to ratepayers. NYPA's exception is denied.

E. Rate Base Treatment for Deferred Overhaul and Local Law 11 Expenditures

DPS Staff had proposed that two O&M costs be recovered over more than one year with carrying charges accruing at the other customer capital rate. The Company had no objection to the longer recovery period, provided carrying charges would accrue at its overall rate of return.

The judges concluded that use of the other customer capital rate would confiscate utility property unless it were established that the Company could finance the costs at that rate.²⁹⁷ Specifically, the judges said that adoption of DPS Staff's proposal would be contrary to the fundamental tenet that the Company should be able to recover its reasonable costs of doing business, including a reasonable opportunity to earn a fair rate of return.

DPS Staff excepts, arguing that the issue is not about recoverability, but carrying charges.²⁹⁸ As to the latter, it says the historic practice of employing the other customer capital rate reflects the common utility practice of financing such costs with short-term instruments.²⁹⁹ Likewise, it contends the standard treatment of costs that are unknown and subject to

²⁹⁷ R.D., pp. 309-312.

²⁹⁸ DPS Staff's BoE, pp. 64-65.

²⁹⁹ This argument was not offered in DPS Staff's trial briefs.

reconciliation is to accrue carrying charges at the other customer capital rate. According to DPS Staff, rate base treatment is usually afforded only to known and verified costs.

The Company replies that DPS Staff's exception rests primarily on what DPS Staff calls past practice by the Department and in part on one reference to a prior order adopting the terms of a joint proposal. The latter order concerns a steam rate plan in which there was no dispute about carrying charges.

The Company also denies that rate base treatment is afforded only to known and verified costs, noting that the FERC cash working capital formula employed for many years is based on a forecast of certain O&M expenses and that the result is nevertheless included in rate base.

We are authorizing carrying charges for these expenses based on the other customer capital rate in the Rate Year and the Company's overall rate of return thereafter.

The interest rate on other customer capital, such as gas supplier refunds, is based on the composite yields of intermediate term, A-rated corporate bonds and an index of municipal bonds. The rate for 2009 is 6.6%. Unlike customer deposit rates, there is no reduction to the 6.6% on account of administrative costs.

The Company can reasonably be expected to finance these projects in the Rate Year with short term debt and without incurring administrative costs associated with customer deposits. The Company's current commercial paper rates, meanwhile, are extremely low, at just under .5%. In these circumstances, we are satisfied that use of the other customer capital rate in the Rate Year will not be confiscatory. Going beyond the Rate Year, however, the unamortized costs will more likely be supported by long-term capital, including a mix of

debt and equity. Accordingly, the Company's proposal is adopted for that period.

X. REVENUE ALLOCATION/RATE DESIGN

A number of parties submitted exceptions or arguments concerning the interim revenue allocation and rate design recommendations in the January 7, 2009 recommended decision. The issues raised include whether a report should be submitted to us or a separate recommended decision should be issued for exceptions on Phase II issues, the pros and cons of an across-the-board revenue allocation, the appropriate allocation of a \$30 million revenue requirement element attributable to a forecast \$30 million reduction in TCC revenues, and the reasonableness of the Company's 2005 embedded cost of service study.

As discussed below, we are addressing all of the Phase II issues finally at this time. The arguments about interim recommendations, accordingly, are moot.

As to whether a report should have been submitted to us or a separate recommended decision should have been issued on all Phase II issues, we reiterate that issuance of a recommended decision, even if preferable, was not an option as a practical matter even with the 25-day suspension date extension through April 30, 2009. Severing the Phase I and Phase II issues might have resulted in unwarranted customer confusion from multiple rate changes in a short period of time. We also prefer to consider simultaneously the issues about rate of return, low-income discounts, the residential/religious customer charge, and the level of Company revenues at risk under various performance mechanisms.

A. 2005 ECOS, Revenue Allocation, and Tolerance Bands

Arguments concerning the Company's Embedded Cost of Service Study for calendar 2005 (the 2005 ECOS), the proper

allocation of revenue requirement, and appropriate tolerance bands to apply when using the 2005 ECOS are summarized next, followed by one discussion. The basic issue presented is whether approximately \$15.0 million in annual revenue requirement should be shifted to NYPA customers before any revenue increase (the Company's position), whether only \$6.7 million should be shifted to NYPA customers before any revenue increase (DPS Staff's position), or whether no shift is warranted (NYPA's, the NYC Government Customers', and Westchester's position).³⁰⁰

1. 2005 Embedded Cost of Service Study

For the reasons that follow, the Company argues that its 2005 ECOS should be relied upon for purposes of realigning class revenues before any revenue increase, allocating any incremental revenue increase, and designing specific rates to recover each class's revenue requirement:³⁰¹

- a. The validity of the Company's 2005 ECOS was established in the Company's last electric rate case. At that time, criticisms of the Company's study by other parties were rejected (2008 Rate Order, p. 134) and an additional \$15 million of revenue requirement was allocated to NYPA based on the study's results. The fact that the entire \$30 million NYPA deficiency indicated by the study was not allocated to NYPA reflected our desire to ameliorate harsh impacts and does not undermine the substantive validity of the study or its results.
- b. This Commission has frequently relied upon the results of an ECOS for more than one rate year. Accordingly, reliance on the Company's 2005 ECOS in the last case is no barrier to relying on it again.
- c. The criticisms of the Company's study in this case are the same as those rejected in the Company's last electric rate case.

³⁰⁰ The NYC Government Customers and Westchester are NYPA commodity customers.

³⁰¹ The Company's Initial Brief, pp. 431-440.

d. Going beyond the 2008 Rate Order, the evidentiary record here establishes that the criticisms of other parties do not provide any basis for ignoring the results of its 2005 ECOS. For example:

- i. DPS Staff's and the NYC Government Customers' concerns notwithstanding, the Company's relative weighting of Non-Coincident Peak (NCP) 60% and Individual Customer Maximum (ICM) demand (40%) for the residential classes remains valid unless and until a proposed Company load study is conducted and establishes otherwise.
- ii. Various studies introduced by a witness for the NYC Government Customers are fraught with errors. For example, data from different years are mixed together, some data are excluded and other data are erroneous. The Company also disagrees with the contention that some of its transformer costs are customer-related, arguing its large transformers are properly treated as demand-related. It states that a concern about the allocation of high-tension costs to residential heating load ignores that NYPA residential heating load is treated in the same manner.
- iii. Various studies introduced by NYPA witnesses are likewise fraught with errors and do not undermine the Company's 2005 ECOS. Among other things, NYPA's load is underestimated,³⁰² an update of rate base is not complete, NYPA and Company load data from different years are used, and no load research results are provided. If the identified errors are corrected, this suggests the NYPA class is deficient by \$18.7 million, or more than the \$15.0 million the Company is proposing to reallocate to the NYPA class before any revenue increase.

NYPA argues that the Company's 2005 ECOS study is fundamentally flawed as of the date it was completed, and significantly out of date for purposes of the Rate Year.

³⁰² Specifically, 54 MW of Kennedy Airport load was excluded and NYC public building load was significantly underestimated.

As to the fundamental flaws, NYPA argues:³⁰³

- a. NARUC's 1992 Cost Allocation Manual states that total revenue requirement of a utility is allocated to the various classes in a fashion that reflects the cost of providing service to each class. Company assertions to the effect that the NARUC manual does not apply to the allocation of revenue increases are inconsistent with the text of the NARUC Manual and should be rejected.
- b. The Company proposes to allocate the revenue requirement based on the Company's forecast revenues before any rate increase. This approach implicitly and improperly assumes that costs the Company incurs to provide service in the Rate Year will be in the same proportion to each other as the costs that underlie the rates used to forecast revenues. This assumption can only be true if customer classes are growing at the same rate and all investments in rate base are made in the same proportion to each other as they were in the past.
- c. A second fundamental flaw is that in situations where the Company's ECOS suggests a class deficiency or surplus of a specified dollar amount, the Company proposes to adjust rates in a multiplicative way that goes further than is necessary to eliminate the class dollar deficiency or surplus.
- d. While the Company asserts that its approach was previously adopted, this argument is undermined because many of those decisions involved adoption of terms that were the product of the give and take among parties in negotiations. Moreover, the NYPA panel witnesses have combined experience of more than 80 years and none of them has ever seen any other utility in the country allocate revenue requirements in the manner the Company employs (i.e., based on forecast revenues rather than costs). Neither has the Company, the party with the burden of proof, provided any other authority to support its approach.

NYPA's contentions about the 2005 ECOS being out of date are as follows:³⁰⁴

³⁰³ NYPA's Initial Brief, pp. 11-15.

³⁰⁴ NYPA's Initial Brief, pp. 18-20.

- a. Between 2005 and 2010, the Company expects its plant in service will increase by \$6 billion, with \$4.7 billion of that occurring between 2008 and 2010.
- b. In the same period, the Company expects its annual O&M expenses will increase from \$0.88 billion to \$1.743 billion.
- c. It is not reasonable to assume NYPA's usage would impose the same burden on the Company's T&D system as it did in the past in light of these changes. Indeed, the Company expects transmission plant, over which NYPA customers receive service, will decline from 16.77% of total T&D in 2005 to 15.72% of total T&D plant in 2010. The Company says the percentages are about the same but the change shows that NYPA's share of costs is going down and the 2005 ECOS study does not reflect this.
- d. Exhibit 200 (a Company press release dated May 12, 2008) shows that the Company identified the increased expense of serving the electronic equipment of residential customers as a major driver of its requested revenue increase. The cost of providing service to NYPA was not so identified.
- e. The Company has not performed a study of NYPA's demand as a percentage of the system total since 2005; the Company forecast panel did not reflect NYPA DSM initiatives; data show that 13% of the Company's billing demand data for NYPA customers are estimates; and all of these factors erode confidence in the 2005 ECOS.
- f. The 2005 ECOS fails to reflect the \$15.1 million incremental revenue shift to NYPA in the Company's last electric rate case nor does it reflect the contemporaneous decision to bar NYPA from enjoying any portion of the Company's net Transmission Congestion Contract (TCC) revenues.

Other arguments offered by NYPA in opposition to use of the 2005 ECOS are as follows:³⁰⁵

- a. Another way of saying that the 2005 ECOS is out of date is that the Company has failed to meet its burden of proving that a NYPA revenue deficiency will exist in the Rate Year that is any greater than any other customers'.

³⁰⁵ NYPA's Initial Brief, pp. 15-18.

- b. The contention that it is reasonable to rely on ECOS studies for many years is suspect and, in any event, is undermined because terms of prior decisions adopting such a course of action were frequently the product of the give and take in negotiations among interested parties.
- c. The decision in the Company's last electric rate case, to address \$15.1 million of an indicated \$30 million NYPA revenue deficiency, is not a valid basis for requiring a further \$15 million or greater revenue shift here. As stated by the NYC Government Customers, the 2008 Rate Order, p. 135, expressly stated that it was without prejudice to subsequent rate periods.
- d. The primary reason that the Company did not provide an up-to-date ECOS in this case is that it did not have time to prepare one following the 2008 Rate Order.
- e. The Company's failure to provide an up-to-date ECOS in this case is a violation of 16 NYCRR 61.3. That rule requires utilities to provide the number of units of service rendered for each class, revenue per unit, and the detailed cost of service rendered in each of the last three years. The Company's counter argument, that it provided five years of financial data, is erroneous because such data is Company-wide, and neither differentiated by native load class nor by (1) NYPA, (2) Economic Development Delivery Services, and (3) the Company's retail customer classes combined.

Further NYPA arguments critical of the 2005 ECOS,

are:³⁰⁶

- a. NYPA's arguments against the use of the 2005 ECOS in this case are not the same as those it made in the Company's last electric rate case, but now focus primarily on the study's age.
- b. NYPA undertook its own cost study, which the Company criticizes for data, estimates, and assumptions used, only because the Company refused to perform one and refused to supply data NYPA requested (Tr.

³⁰⁶ NYPA's Reply Brief, pp. 9-14.

4752-53; Ex. 202).³⁰⁷ That does not in any event relieve the Company of its burden of proof.

- c. The Company's Initial Brief has not in fact challenged NYPA's interpretation of 16 NYCRR §61.3.
- d. The Company's claim that NYPA would "omit the step of adjusting a class's revenue by its deficiency or surplus in allocating the revenue increase . . ." is not correct. NYPA would not oppose an adjustment if a sound ECOS legitimately showed a deficiency or surplus existed.

The Company counters NYPA's arguments with these contentions:³⁰⁸

- a. NYPA is incorrect when it suggests that its customers receive only transmission service and are not served by the Company's distribution system. NYPA is served by the Company's distribution system and growth in Company distribution plant can affect NYPA. In any event, the transmission plant share of total plant remains about the same, with a decrease of approximately one percentage point (Tr. 1055-56).
- b. NYPA fails to acknowledge its own blatant 155 MW underestimation of its transmission allocator, correction of which would increase NYPA's transmission demand allocator by 10% (Tr. 1072-73; Ex. 452).

Using the Company's original \$654.1 million electric revenue request as a base, the NYC Government Customers strongly oppose the Company's proposal to allocate \$18.5 million annually to the NYPA customer class beyond what would be allocated based on a flat percentage increase for all classes. The basic arguments offered by these customers are as follows:³⁰⁹

- a. The Company's proposal is based on the results of a 2005 ECOS but that study is outdated because new rates were approved subsequently, billions of

³⁰⁷ The Company declined to provide individual customer metered and billing data for 2006 and 2007 on the grounds that the information is proprietary and that it would need to conduct a study to respond.

³⁰⁸ The Company's Reply Brief, pp. 146-47.

³⁰⁹ NYC Government Customers' Initial Brief, pp. 37-41 and 46-49.

dollars of additional costs have been incurred by the Company, and usage patterns have changed. For example, the Company did not update the 2005 ECOS to reflect new rates that went into effect earlier in 2008, even though the purpose of a cost study is to measure the adequacy of current rates compared to the costs customers impose on the system. Nor did the Company update the study to reflect the allocation of \$8 million of additional revenue requirement to NYPA related to TCCs in the Company's last electric rate case.

As to cost changes, rate base and O&M costs at the time of the 2005 ECOS were \$9.5 billion and \$0.88 billion, respectively, while comparable figures for the Rate Year are projected to be \$14.6 billion and \$1.742 billion, respectively. Turning to changed usage patterns, energy and demand figures have not been updated by the Company. Nor has it reflected its projection of much higher energy sales growth for the NYPA customer class (7.6%) compared to that for native load customers (2.4%).

- b. Whether or not the 2005 ECOS is out of date, it is materially flawed to the extent it:
 - i. Is arbitrarily based on a 50%/50% weighting of individual customer maximum demand and class non-coincident peak demand for all classes with the exception of the SC 1 residential/religious and SC 7 residential/religious heating classes for which a 25%/75% weighting is employed. The 25%/75% weighting for SC 1 and SC 7 assumes diversity benefits (usage by different customers in a class at different times) much greater than assumed by other utilities and greater than what the Company assumed in a separate case concerning standby rate design. This flaw was flagged by DPS Staff in the Company's last electric rate case and is part of the basis for DPS Staff's support for a 15% tolerance band in this case compared to the 10% adopted in the Company's last electric rate case.
 - ii. Erroneously failed to assign any transformer costs to the customer cost category.
 - iii. Unreasonably relies on class summer demand to allocate High Tension Plant Costs to the SC 7, SC 12 multiple dwelling space heating,

and SC 12 time-of-day classes, even though the winter demands for these classes far exceeded their summer demands, and even though the greater of summer or winter demands were used to allocate such costs for all of the Company's other customer classes. It would be more reasonable for the Company to allocate these costs to all classes using either coincident peak (or summer demands) or non-coincident peak (the higher of summer or winter demands). The use of different allocation methods for different classes is not reasonable.

The NYC Government Customers also respond to contrary arguments they expect the Company will make, as follows:³¹⁰

- a. The absence of a sufficient time to prepare a new cost study for this case is not a good reason to rely on the old study and to allocate extra revenue requirement to the NYPA customer class. In any event, the Company was able to quickly update the old study in part when asked to do so by DPS Staff in a discovery request.
- b. While a revenue deficiency of approximately \$30 million was acknowledged in the Company's last case and approximately half of that was addressed at the time, the Company has not established that revenues, costs, and usage patterns have and will remain static. This is another reason why DPS Staff supports use of a broader tolerance band in this case (15% compared to 10% adopted in the Company's last electric rate case). Moreover, the decision in the Company's last case expressly stated that it was without prejudice to allocations in periods beyond the April 1, 2008 through March 31, 2009 rate year.
- c. It is true that past multi-year rate plan allocations have been based on one ECOS cost study, but that is usually in the context of a decision adopting rate plan terms that resulted from the give and take in negotiations among interested parties.
- d. The Company failed in its effort to establish that plant growth has had no effect on the reliability of the 2005 ECOS (Ex. 372) because a one percentage point increase in distribution plant identified in

³¹⁰ NYC Government Customers' Initial Brief, pp. 41-46.

that effort as a percentage of total plant is significant in the context of a \$5.9 billion increase in total plant, especially given that NYPA receives a relatively smaller allocation of distribution plant. The Company's effort also ignores that shifts in the types of distribution plant investment could also have significant effects on the results of the ECOS.

The Company answers the NYC Government Customers' points, declaring:³¹¹

- a. The \$15 million assessment of the NYPA deficiency from the 2008 Rate Order and the disallowance of any NYPA TCC benefits have no significant effect on the results of the 2005 ECOS. A rerun of the 2005 ECOS with current rates, reflecting those changes, produced a NYPA deficiency of about one-half the originally filed \$30.2 million deficiency (Tr. 1124-35).
- b. The Company's detailed ECOS uses costs, revenues, usage, and load research data from the same time period, while NYPA and the NYC Government Customers selected a combination of data from different periods that favor them at the expense of other customers (Tr. 1159). The NYC Government Customers' witness's study was misaligned, less than credible, and led to self-serving results (Tr. 1060-61).
- c. The functional relationship between transmission and distribution plant mix in the 2005 ECOS accurately reflects the current composition of the Company's plant assets.

Westchester opposes any reallocation of revenues among service classes that would shift additional costs to NYPA and its customers, because:³¹²

- a. The 2008 Rate Order did not direct that any remaining NYPA deficiency be eliminated in this case.³¹³
- b. From 2005 to 2009, Consolidated Edison will have increased non-production plant by \$6 billion, or

³¹¹ The Company's Reply Brief, pp. 145-46.

³¹² Westchester's Initial Brief, pp. 18-21.

³¹³ Citing the 2008 Rate Order, p. 134.

40%. The majority of plant additions are for underground distribution, of which NYPA's customers were responsible for only 8.9%, according to the 2005 ECOS. Since NYPA's customers represent 10% of total T&D revenues, an across the board increase would result in NYPA customers paying more than their fair share.

- c. Consolidated Edison has been estimating bills for about 30% of meters serving County facilities and probably those of other municipalities in Westchester and New York City, since before the 2005 ECOS was prepared. The impact or bias caused by the use of estimated billing on the 2005 ECOS is unclear, but sufficient to raise serious questions about the study's validity. Recently, the estimated readings on County facilities have dropped dramatically, so that the anticipated 2007 ECOS may provide more accurate cost allocation factors. Until it is available, any revenue increase should be applied proportionally among Con Edison's and NYPA's customers.

The Company responds to Westchester:³¹⁴

- a. Plant investment through 2009 includes significant amounts in primary distribution and substation assets, allocated based on a high tension NYPA demand allocator of 14.2% (Ex. 143, Table 7, p.1), a cost responsibility percentage that far exceeds NYPA's 10% revenue percentage.
- b. The use of estimated bills in calculating the NYPA revenue responsibility is immaterial. Estimated bills are issued to customers in every service class and estimated billing determinants are reflected in the development of class demand allocation factors for all service classifications (Tr. 1126).

2. Revenue Allocation

The Company summarizes the steps it took to allocate the originally requested \$654.1 million, taking into account the results of its 2005 ECOS.³¹⁵ It states that the resulting electric revenue increases, including gross receipts taxes, are \$561 million for the Company's retail customers, \$88.7 million

³¹⁴ The Company's Reply Brief, p. 147.

³¹⁵ The Company's Initial Brief, pp. 432-433.

for NYPA customers (including the further \$15 million revenue shift it supports), and \$4.4 million for Economic Development Delivery Service customers.

The Company anticipates criticisms of its allocation methodology by NYPA and the NYC Government Customers on two fronts. The first criticism is that the Company improperly addresses class deficiencies and surpluses at current rates, before allocating any incremental revenue requirement, and that this has an unfair multiplicative effect on NYPA customers. The second is that the Company allocates revenue requirement based on forecast revenues rather than based on forecast costs. As to these contentions, the Company states the following:³¹⁶

- a. There is no proof that the Company's allocation method is not generally accepted in the industry.
- b. The Company's approach has been consistently proposed by it and adopted by in past cases.
- c. The NARUC manual does not specifically address the allocation of rate increases and, thus, does not undermine its allocation methodology.
- d. The purpose of realigning class revenues before allocating incremental revenue requirement is to bring existing revenues closer to costs before allocating any incremental revenue increase based on costs. Omitting this step means cost indications are totally ignored, contrary to sound ratemaking principles (Tr. 1074).³¹⁷
- e. The witness proffered by the NYC Government Customers testified within the past couple of years in support of the Company's approach, in gas and steam rate cases.

DPS Staff states that it reviewed and agrees with the Company's allocation methodology.³¹⁸

³¹⁶ The Company's Initial Brief, pp. 439-440.

³¹⁷ The Company's Reply Brief, p. 148.

³¹⁸ DPS Staff's Initial Brief, p. 264.

Building on their arguments that the Company's 2005 ECOS is outdated and materially flawed, the NYC Government Customers argue that any revenue increase should be allocated across-the-board, on an equal percentage basis. Moreover, they argue this allocation should be subject to further adjustment based on our decision in this case with respect to the allocation of net TCC revenues. Specific arguments in this regard, which focus primarily on why the 2005 ECOS results are not reliable, are as follows:³¹⁹

- a. An update of the Company's 2005 ECOS using current rates and usage factors (Ex. 215, Schedule 1) shows that the NYPA customers' class is not deficient with a tolerance band of +/-10% or +/-15%. The Company's update of the ECOS for revenue changes only (in response to a DPS Staff discovery request) shows a deficiency for NYPA customers of only \$5.5 million with a +/-15% tolerance band. Even if Ex. 215, Schedule 1 needs to be corrected, as the Company argues, this shows there is no NYPA customer class deficiency using a +/-15% tolerance band and a deficiency of only \$4.45 million using +/-10% tolerance band (Tr. 1165, Ex. 283).
- b. Exhibit 215, Schedules 2 and 5, build on the first update, using proxies to reflect on a gross basis the projected increase in capital and O&M spending, and employing reasonable low tension demand allocators. These both suggest there is no NYPA class revenue deficiency. While these updates are not advocated as a basis for allocating revenue requirement, they show that the Company's 2005 ECOS is not reliable.

Anticipating that the Company will criticize their update efforts, the NYC Government Customers acknowledge such efforts are not perfect and reiterate that they do not rely on them in support of a less than overall percentage increase for NYPA class customers. They suggest their update efforts should nevertheless be given some weight given the Company's failure to

³¹⁹ NYC Government Customers' Initial Brief, pp. 50-54 and NYC Government Customers' Reply Brief, pp. 14-16.

include an updated ECOS in its direct case, as well as the Company's subsequent update in a discovery response that reflects only changes in revenues since 2005.

The Company offers these responses to the arguments of NYPA, the NYC Government Customers, and Westchester:³²⁰

- a. The NYC Government Customers have in the past presented testimony in support of the Company's methodology of using forecast revenues in conjunction with the results of a historical ECOS to preserve movement toward cost-of-service ratemaking (Tr. 1075).
- b. NYPA's opposition to the Company's methodology in this instance is purely result driven, because the Company's methodology allocates a higher share of the rate increase to NYPA. When NYPA proposes to realign rates to recognize TCC revenues as NYPA believes proper, NYPA uses the same methodology the Company has used here, because that methodology produces a lower allocation to NYPA.

3. Tolerance Bands

If we decide to rely on the Company's 2005 ECOS for purposes of allocating any revenue increase in this case, NYPA argues that a +/-20% tolerance band should be employed instead of the +/-10% tolerance band favored by the Company or the +/-15% tolerance band supported by DPS Staff.³²¹ NYPA's reasons are as follows:³²²

- a. DPS Staff supported use of a +/-15% tolerance band in the Company's last electric rate case because of one identified problem (pertaining to two demand allocators) beyond the usual concern about the accuracy of such studies.

³²⁰ The Company's Reply Brief, p. 144.

³²¹ As noted above, any class rate of return within +/-20% of the Company's overall rate of return in the study year would be treated as if its class rate of return is equal to the Company's overall rate of return in that year. Classes with rates of return below or above the tolerance band would be treated as having insufficient or excess revenues, respectively.

³²² NYPA's Initial Brief, pp. 20-23.

- b. DPS Staff still has the same concerns and raised three new ones (study a year older, study not updated for significant incremental capital expenditures since the 2005 ECOS study, and study relies on a dated class demand study).
- c. Given the additional problems that even DPS Staff acknowledges, and taking into account all the other significant problems with the 2005 ECOS identified by other parties, a tolerance band of at least +/- 20% would be reasonable.
- d. No weight should be given to the Company's proposed +/-10% tolerance band because the Company does not address that the study is one year older, and the Company lacks any reasonable support for the underlying contention that class relationships in the Rate Year will be the same as they were in 2005.

The NYC Government Customers argue that a 20% tolerance band should be applied for purposes of determining if any classes warrant a revenue change greater or lesser than an equal percentage increase. Its reasons are as follows:³²³

- a. The Commission adopted a 20% tolerance band in a 2003 decision affecting electric and gas rates for Rochester Gas and Electric Corporation.
- b. DPS Staff's support for a 15% tolerance band is superior to the Company's 10% proposal. However, DPS Staff witnesses did not consider the Company's projected uneven sales growth rates among customer classes, a decrease in transmission plant as a percentage of total plant, and the effects of a \$23 million revenue shift to NYPA in the last case (\$15 million plus \$8 million related to TCCs). Accordingly, it is not reasonable for DPS Staff to continue to support a +/-15% tolerance band.

The Company does not discuss affirmatively on brief why a tolerance band of +/-10% should be employed. However, it argues that DPS Staff's support for use of a 15% tolerance band is unfounded for the following reasons:³²⁴

³²³ NYC Government Customers' Initial Brief, pp. 55-57 and NYC Government Customers' Reply Brief, pp. 17-18.

³²⁴ The Company's Initial Brief, pp. 434-435.

- a. The proposed tolerance band expansion is arbitrary and rests on DPS Staff's dissatisfaction with the respective weights the Company accords to Non-Coincident Peak and Individual Customer Maximum demands, a concern, as discussed above, it believes is premature.
- b. A change in the tolerance band undermines the goal of aligning class revenues and cost of service.

In anticipation of this contention, DPS Staff argues as follows:³²⁵

- a. In the last Consolidated Edison electric rate case, DPS Staff proposed use of a 15% tolerance band because of concerns over the D08/D09 allocation factors for the SC 1 and SC 7 customer classes and lack of a specific load diversity study. DPS Staff found that a 15% tolerance band better captured the range of possible D08/D09 allocation factors than a 10% tolerance band and was a conservative approach (Tr. 4553).
- b. In this case, DPS Staff has the same concerns about the D08/D09 allocation factors for SC 1 and SC 7 customer classes. Moreover, the 2005 ECOS is a year older and relies on a dated class demand study. It also does not reflect the significant capital expenditures the Company has made in the years since the study occurred and the declining ratio of transmission plant to total transmission and distribution plant (Ex. 372, Tr. 1122). Thus, DPS Staff's 15% tolerance band is even more preferable to the Company's 10% tolerance band than it was in the last Consolidated Edison electric rate case.
- c. The 15% tolerance band was a sufficiently conservative approach in the last case that it remains adequate to address the uncertainties of the dated class demand study, the D08/D09 allocation factors, and the pattern of Company capital investments over the last three years.

The Company responds to DPS Staff, contending:³²⁶

- a. DPS Staff's argument, that a 15% tolerance band adequately captures the range of possible results of a load diversity study, is invalid. It would not

³²⁵ DPS Staff's Initial Brief, pp. 265-267.

³²⁶ The Company's Reply Brief, p. 144.

capture an outcome where residential customers are assigned less costs and NYPA customers more costs through a reduction in Individual Customer Maximum demands for residential customers, for example, or *vice versa*.

- b. Raising the tolerance band has the same directional impact on both residential and NYPA classes, lowering the deficiencies of both residential and NYPA classes, unlike the potential results of a load diversity study.

NYPA dismisses as a "post hoc rationalization" DPS Staff's characterization of its prior use of a +/-15% tolerance band as a conservative approach, because DPS Staff did not characterize it that way in its briefs in that case or in its prefiled testimony in this proceeding. It did so only on cross-examination in this case (Tr. 4553).³²⁷ In addition, NYPA says the shift of about 6% (or one percentage point) away from transmission investment identified by DPS Staff³²⁸ would significantly reduce the revenue allocation to NYPA, because the distribution allocator for NYPA is only about 60% of the transmission allocator (8.8% v. 13.7%). NYPA maintains this shift supports use of its proposed +/-20% tolerance band.

4. Discussion

The Company's 2005 ECOS is the same study we relied on in the Company's last electric rate case, along with a +/-10% tolerance band, for purposes of allocating revenue requirement. NYPA and other parties emphasize significant increases in plant investment and expenses, and changes in load and sales since 2005, in support of their fundamental contention that the Company's 2005 ECOS is stale. We agree with DPS Staff, however, that the most reasonable way to reflect this information pending

³²⁷ NYPA's Reply Brief, pp. 14-16.

³²⁸ From 16.77% to 15.72%, identified in Ex. 372 and cited in DPS Staff's Initial Brief, p. 266.

a new study is to increase the tolerance band from +/-10% to +/-15%.

We also examined in the Company's last electric rate case some of the same criticisms raised here, including whether the Company gives appropriate weightings to non-coincident peak and individual customer maximum demands and whether those weightings are consistent with those employed by the Company in the standby rate proceedings. We decline to consider these issues pending receipt of the new ECOS we understand the Company is preparing for its next electric rate filing.

We reject outright NYPA's contention that 16 NYCRR 61.3 requires the filing of an updated ECOS in each case, presenting cost data for the three years immediately preceding a rate case. The Company properly understands that rule to pertain to information affecting the Company's revenue requirement, rather than to all information necessary to determine a fair and reasonable allocation of required revenues among various service classifications. Reading 16 NYCRR 61.3 in the context of 16 NYCRR 61.1 through 61.10 confirms that the Company's understanding is correct.

One methodological dispute discussed on the merits concerns whether it is reasonable for the Company, assuming a reliable ECOS, to reallocate existing revenues before allocating any incremental revenue requirement among the Consolidated Edison native load, NYPA, and Economic Development Delivery Service groupings, on the one hand, and among Consolidated Edison's full service and retail access customer classes, on the other. We reject the criticisms of the Company's approach.

If a specific native load customer class is generating an inadequate rate of return before any rate increase, and putting aside whether we might want to move gradually in the direction of cost to minimize harsh customer impacts, two reasonable alternatives are to: (1) shift revenue requirement

first to bring up the class rate of return to where it should be, and allocate any incremental revenue requirement on an across-the-board basis; or (2) allocate an above-average increase to each class as necessary to eliminate the existing class revenue deficiency and to cover any incremental revenue requirement prospectively. The Company's approach is the first of these two alternatives and we find it is reasonable on this basis.

An issue not addressed directly by the interested parties is whether the Company's 2005 ECOS should be used for purposes of shifting existing revenues among the Company's native load electric delivery service customer classes before allocating any incremental revenue increase. Given our decision above to rely on the 2005 ECOS, the Company is authorized to reallocate existing revenues among its full service and retail access classes in accordance with the study's results, subject to use of a +/-15% tolerance band.

B. TCC Treatment vis-à-vis NYPA

1. Background

In the years prior to the NYISO, the Company's native load customers generally paid for their use of the Company's transmission system through rates paid directly to the Company. The New York Power Authority paid the Company directly for transmission and distribution services for its customers through rates in a separate Company tariff. The latter arrangement was pursuant to the terms of contracts between the Company and NYPA. The last such contract was executed in 1989, about ten years before formation of the NYISO.

Things changed upon the advent of the NYISO, the New York wholesale commodity market, and the use of congestion pricing as a means to assign a value to transmission resources. Transmission owners like the Company were assigned Transmission

Congestion Contracts (TCCs), each of which represent a financial right to transmit one megawatt from a point of injection to a point of withdrawal on its system. The rights associated with a utility's TCCs are auctioned off from time to time and utilities, among others, bid for the use of such rights to serve their retail customers. Payments by winning bidders are made to the NYISO and receipts, called TCC auction revenues, are distributed by the NYISO to TCC owners.

NYPA, which had interests in use of the Company's transmission system under the 1989 contract referred to above, had two basic options with respect to those rights when the ISO was formed. Under the first, it could claim grandfathered contract rights, continue to pay rates under a Company tariff pursuant to the 1989 contract, pay the NYISO for congestion costs and offset those congestion costs using the rents or auction revenues received from the grandfathered contract rights. Under the second option, NYPA could assign its grandfathered rights to the Company, continue to pay the Company's applicable tariff rates under the 1989 contract, pay the NYISO for congestion costs, and be reimbursed by the Company for all of such congestion costs.

The Company and NYPA agree that when the NYISO was first established, NYPA selected the first of these two options. After it became apparent that the TCC revenues NYPA was receiving exceeded its congestion costs, NYPA and the Company entered into a new contract on May 11, 2000, under which NYPA selected a mix of the first and second options.³²⁹ Specifically, under the first option, NYPA elected to be excused from having to pay NYISO congestion costs with respect to its in-City Poletti and KIAC units and to receive congestion revenues associated with these rights from the NYISO. It elected to do

³²⁹ Ex. 419.

likewise with its rights to transmission paths from various NYPA upstate generation resources, including from the Niagara and St. Lawrence power projects to East Fishkill. NYPA simultaneously elected to transfer to the Company 1,680 MW of TCCs south of East Fishkill, to pay congestion costs to the NYISO, and to be reimbursed by the Company for NYPA's actual congestion payments to the NYISO (the second option).

In the period following execution of the May 11, 2000 contract, revenues associated with the transferred TCCs generally continued to exceed NYPA's associated congestion costs and the net of TCC revenues minus NYPA's congestion costs (net TCC revenues) have been used as an offset to the Company's delivery service revenue requirement. This is accomplished by imputing a level of net TCC revenues along with auction revenues from the Company's own grandfathered TCC rights (total net TCC revenues) in the rate case revenue requirement calculation and either passing back or recovering from customers differences between forecast and actual total net TCC revenues.

A three-year rate plan adopted in 2005 provided that NYPA and its retail customers would receive 14.22% of only the first \$60 million of net TCC revenues received by the Company in each of the three-rate years. The 14.22% reflected NYPA's share of the Company's total load. This rate plan term was accepted as an element of a joint proposal negotiated and executed by a number of parties. It reflected in part that there was a dispute in that case among interested parties about whether NYPA should share in any total net TCC revenues.

In the Company's last electric rate case, it was determined that NYPA and its customers should not enjoy any

portion of the Company's total net TCC revenues going forward.³³⁰ The primary reasons for this determination were that NYPA's interest is limited to revenues from TCCs it transferred to the Company and that such interest is further limited to NYPA being reimbursed for its congestion costs related to the same TCCs. It is uncontested that, all other things be equal, this decision increased by approximately \$8 million NYPA's share of the Company's total annual electric delivery service revenue requirement.

NYPA and its customers complain here that the last decision is incorrect and was based solely on briefs because there was no testimony or cross-examination on the issue. NYPA and its customers ask that the issue be examined anew based on a more comprehensive record here.

2. The Arguments

NYPA argues that it and its retail customers should enjoy a share of the Company's annual net TCC revenues, for the following reasons:³³¹

- a. As a matter of principal, the allocation of net TCC revenues should be consistent with that of any other component of cost of service.
- b. The Company has three major sources of net TCC revenues of which two are as follows:
 - i. net revenues from auctions of the Company's native load TCCs totaled \$89.5 million and \$98 million in 2005 and 2006; and,

³³⁰ The 2008 Rate Order, pp. 27-28, and Case 07-E-0523, Consolidated Edison Company of New York, Inc. - Electric Rates, Order Denying Rehearing (issued July 18, 2008). The latter order suggested that there was no need to ameliorate bill impacts on NYPA customers on account of the TCC determination, stating that the simultaneous revenue allocation decision (discussed above) provided adequate amelioration.

³³¹ NYPA's Initial Brief, pp. 26-29.

- ii. net revenues or “rents” from NYPA’s grandfathered rights, transferred to the Company pursuant to the May 11, 2000 contract, totaled \$62 million and \$26.5 million in 2005 and 2006.³³²
- c. The fact that there are net TCC revenues from these two sources shows that the Company’s native load and its NYPA customers are both equally hedged against congestion costs.
- d. The costs of the Company’s transmission system are allocated in its cost-of-service studies using the “D03” allocator. As a result, 13.7% of the Company’s embedded transmission system costs are allocated to NYPA.³³³
- e. A decision to allocate none of the Company’s net TCC revenues to NYPA and its retail customers is inconsistent with the above described allocation of the Company’s transmission costs and is flatly contrary to cost of service principles.
- f. Moreover, a decision to allocate none of the Company’s net TCC revenues to NYPA and its customers ignores that upon the formation of the NYISO, NYPA had an option under which net TCC revenues from NYPA’s grandfathered rights transferred to the Company would have been paid to NYPA, rather than becoming a “windfall” for the Company and its retail customers.
- g. As previously discussed, the prior determination should be reversed as there was no testimony or cross-examination on this issue at the time.
- h. In the event we agree that NYPA and its retail customers should enjoy some of the Company’s net TCC revenues going forward, a rate element should be adopted that would permit NYPA to participate in any reconciliation of forecast and actual net TCC revenue. Such a reconciliation is currently accomplished solely through the Monthly Adjustment Clause (MAC) and NYPA and NYPA customers are not subject to that rate element.

³³² A third revenue source is so-called residual TCC auction revenues. Tr. 2538-39.

³³³ NYPA does not discuss why it is appropriate to employ an allocator set forth in the 2005 ECOS that NYPA claims is defective and stale.

- i. In the event there are any unresolved issues with respect to implementation, NYPA offers to meet with the Company and interested parties to resolve them prior to the Company's filing of new tariffs in compliance with the terms of the final order in these cases.

For the reasons that follow, the Company argues that none of its net TCC revenues should be allocated to NYPA and NYPA's customers:³³⁴

- a. NYPA is incorrect when it suggests the Company had "net" TCC revenues of \$151.5 million and \$124.5 million in 2005 and 2006, respectively. Among other things these figures ignore:
 - i. The Company's payments to the NYISO for congestion costs embedded in the NYISO's day-ahead energy prices.³³⁵
 - ii. The Company's payments to the NYISO for congestion costs embedded in the NYISO day-ahead energy prices paid by ESCOs to serve their commodity customers (or 61% of the Company's native load.)
 - iii. Excess congestion rents that are credited to NYPA through reduced Transmission Service Charges for wheeling through the Company's service territory (which credits are admittedly not as significant as day-head congestion costs incurred by the Company).
 - iv. Congestion costs embedded in Transmission Usage Charges paid by the Company and ESCOs under bilateral energy purchases.
 - v. Additional congestion rents collected by NYPA by selling its in-City generation in the NYISO market or to other energy suppliers.

³³⁴ The Company's Initial Brief, pp. 446-451.

³³⁵ Citing information on the NYISO website, the Company reports that the NYISO estimates that congestion costs comprised about 10% of average market energy prices in New York City in 2007. The Company acknowledges that NYPA might have also incurred such costs, but implies that such costs should be ignored because NYPA had alternatives because of its in-City generation while the Company did not because it previously divested most of its in-City generation.

- vi. In sum, the net TCC revenue figures calculated by NYPA are "hypothetical."
- b. The reason NYPA and the Company entered into the May 11, 2000 contract is that NYPA was collecting congestion revenues under grandfathered TCCs that were greater than NYPA's cost for the transmission rights it had before the NYISO was created.
- c. The May 11, 2000 contract guaranteed that NYPA would never incur costs for delivery service in excess of applicable delivery service tariff rates, regardless of the congestion costs, and no other Company customer enjoys such a guarantee.
- d. NYPA should not be heard to complain about the allocation of net TCC revenues given that NYPA has not been using its in-City generation to meet the in-City load of its retail customers.³³⁶ Rather, energy from those facilities has either been sold into the NYISO market or pursuant to bilateral contracts, either of which would result in congestion revenues, both for transmission rights and the energy NYPA sells, something clearly not intended by the May 11, 2000 contract.³³⁷
- e. No party to this proceeding has presented any reason to set aside the initial and rehearing decisions on the same issue in the Company's last electric rate case. Among other things, it was determined at that time that NYPA's interest is limited to and addressed entirely by the Company's reimbursement of NYPA's congestion costs.

DPS Staff likewise argues that the Company's net TCC revenues should not be allocated to NYPA or NYPA's retail customers, for the following reasons:³³⁸

³³⁶ The Company says the amount of NYPA in-City generation used for NYPA load in 2005-2007 was insignificant, decreasing from 5,599 MWh in 2005 to zero in 2007.

³³⁷ NYPA's Initial Brief, p. 30, anticipates this argument and says this is not a proper forum for an investigation of how NYPA bids its generators into the market for the maximum benefit of its customers. NYPA argues, alternatively, that its bidding strategies are consistent with the May 11, 2000 contract.

³³⁸ DPS Staff's Initial Brief, pp. 269-270.

- a. DPS Staff examined the total amount the Company paid to NYPA from January 2005 through June 2008 to reimburse the latter for its congestion costs under the May 11, 2000 contract.
- b. DPS Staff compared those reimbursements to the Company's total TCC revenues for native load and NYPA load in the same period.
- c. The result is that NYPA received 27% of the total.
- d. 27% exceeds the "D03" allocator of 13.7% and, thus, NYPA is already receiving more than its fair share of the Company's TCC revenues.
- e. Accordingly, the current allocation of net TCC revenues is reasonable.

Anticipating contrary arguments by NYPA and NYPA's customers, DPS Staff goes on to argue that:³³⁹

- a. Under the terms of the May 11, 2000 contract, NYPA and NYPA's retail customers are entitled solely to reimbursement of congestion costs actually incurred.
- b. This makes sense as NYPA is guaranteed that its congestion costs will be fully reimbursed.
- c. The Company customers have no such guarantee; TCC revenues received might or might not fully cover congestion costs incurred on behalf of such customers. There clearly are times each year when TCC revenues are less than congestion costs.
- d. In any event, DPS Staff's analysis establishes that NYPA and its customers are receiving fair treatment on a cost-of-service basis.
- e. Moreover, for some of the reasons presented by the Company and summarized above, NYPA's calculation of the Company's net TCC revenues is flawed and should be rejected.

DPS Staff sees no need for a working group or collaborative to consider any issues related to implementation of NYPA's proposed TCC treatment because it believes the record shows NYPA's proposal is flawed and should be rejected.³⁴⁰

³³⁹ DPS Staff's Initial Brief, pp. 270-275.

³⁴⁰ DPS Staff's Reply Brief, pp. 88-89.

NYPA disagrees with the cost-of-service analysis portion of DPS Staff's recommendation, arguing that a correct analysis would compare the sum of the 13.7% transmission allocator and 100% of congestion costs. If modified in that way, NYPA says, DPS Staff would be in agreement with NYPA and its retail customers.³⁴¹

The NYC Government Customers offer general arguments in support of an allocation of some net TCC revenues to the NYPA customer class. Their arguments are as follows:³⁴²

The allocation of any TCC net revenues to the NYPA customer class in the Company's last rate case was onerous and lacked any record support. This resulted in \$8 million of the \$23 million additional revenue shift to NYPA class customers, beyond what would have been required by an across-the-board increase. These changes were made even though the NYPA class customers provide critical services in New York City.

- a. The record in this case shows TCC revenues far exceed TCC costs. Given that NYPA pays its share of the Company's transmission costs based on the "D03" allocator, it should enjoy a 14.13% share of net TCC revenues.
- b. The current allocation of net TCC revenues unfairly discriminates in favor of the Company's native load customers and against the Company's NYPA class customers.
- c. In order to ensure NYPA class customers enjoy their fair share of net TCC revenues, beyond the \$120 million proposed to be imputed in the calculation of revenue requirements, any such excess should be passed back in a rate element that also applies to NYPA class customers. The Monthly Adjustment Clause (MAC) is currently used to reconcile projected and

³⁴¹ The briefs do not explain why NYPA uses 13.7% and its customers use 14.13%. As noted above, a 14.22% allocation was used in the period April 1, 2005 through March 31, 2008.

³⁴² NYC Government Customers' Initial Brief, pp. 57-59. The referenced revenues include congestion rents and TCC auction proceeds.

actual net TCC revenues and NYPA customers are not subject to that rate element.

Westchester objects to Consolidated Edison's crediting all \$150 million of projected auction revenues consistent with the 2008 Rate Order, which prevented NYPA from benefiting from net TCC auction proceeds.³⁴³ Instead, Westchester supports NYPA's position that NYPA and its customers should share in the net of total TCC revenues in excess of total transmission congestion costs on a pro-rata basis, on the grounds that:³⁴⁴

- a. In Case 07-E-0523 (the Company's last electric rate case), the issue was not adjudicated; the decision was based solely on arguments raised in briefs, without discovery, testimony, or cross-examination. Prior to that decision, NYPA received a share of the Company's first \$60 million in TCC net revenues.
- b. Under the May 11, 2000 agreement in which NYPA assigned its TCCs to Consolidated Edison, the Company reimburses NYPA for NYPA's congestion costs, but the agreement is silent on the ratemaking treatment for the surplus Consolidated Edison retains.
- c. Consolidated Edison's bulk transmission system is integrated and operated as a single unit within the NYISO. The Company has one Open Access Transmission Tariff (OATT) rate on file with the Federal Energy Regulatory Commission that it charges for use of its whole integrated transmission system.
- d. Because Consolidated Edison's delivery system is integrated, NYPA should be permitted to share in any auction proceeds that exceed Consolidated Edison's congestion costs as well as in congestion rents from NYPA-transferred TCCs that exceed NYPA's congestion costs.
- e. NYPA customers should be treated like any other Consolidated Edison customers that use the Company's transmission system. Energy Service Companies'

³⁴³ The \$150 million figure ignores DPS Staff's proposed imputation of \$120 million in these cases. The Company agrees with DPS Staff's proposal and the judges endorsed it in the recommended decision (p. 314).

³⁴⁴ Westchester's Initial Brief, pp. 21-23.

(ESCOs') customers benefit from the Company's TCC revenues, which are applied to all delivery charges whether those customers' energy is supplied by Consolidated Edison or an ESCO.

In response to the Company's and DPS Staff's contentions concerning the allocation of TCC related revenues, NYPA advances these additional arguments:³⁴⁵

- a. DPS Staff's statement--that congestion payments can and will exceed TCC revenues--is unsupported in the record. Every year since inception of the NYISO, "NYPA Grandfathered TCCs"³⁴⁶ have produced higher revenues than the congestion costs they were designed to hedge.
- b. The Company implicitly concedes that a surplus of TCC revenues exists, because it argues that if NYPA's proposal were adopted, that would "guarantee" NYPA would be hedged for more than 100% of its congestion costs.³⁴⁷ NYPA explains that under its proposal it would share in TCC revenues only if more than sufficient to hedge fully congestion costs of the Company's native load customers.
- c. Despite Company and DPS Staff claims of substantial congestion costs included in energy purchases the Company makes, Consolidated Edison failed to quantify or prove such costs exist, even though NYPA requested on discovery that the Company provide its total native load congestion costs.
- d. Any Company suggestion that its customers might have to pay more than their tariff rates and are not hedged for their congestion costs is wrong because:
 - i. The filed rate doctrine precludes charging more than tariff rates.
 - ii. The Company's native load customers are reimbursed for their congestion costs from TCC revenues and excess NYPA Grandfathered TCC congestion rents through the MAC.

³⁴⁵ NYPA's Reply Brief, pp. 17-23.

³⁴⁶ The "NYPA Grandfathered TCCs," however, include both those TCCs NYPA retained and the 1,680 MW of TCC transferred to the Company under the May 11, 2000 contract. NYPA's Initial Brief, p. 26.

³⁴⁷ Citing the Company's Initial Brief, p. 450.

iii. NYPA's proposal would permit NYPA customers to share in excess TCC revenues only after native load customers' congestion costs are fully hedged.

e. DPS Staff is wrong to suggest that NYPA is the beneficiary of a special deal under the May 11, 2000 contract. Like all other NYISO market participants with grandfathered contracts, NYPA is entitled to hedge its customers' congestion costs associated with transmission rights preserved in the underlying agreement (e.g., the 1989 delivery service agreement between the Company and NYPA).

In their reply brief,³⁴⁸ the NYC Government Customers criticize DPS Staff's contention that, because NYPA's transmission cost allocator D03 from the 2005 ECOS is 13.7%, NYPA is receiving more than its reasonable share of the Company's TCC revenues. The NYC Government Customers assert that DPS Staff's analysis is flawed because it is an improper comparison of gross benefits to NYPA divided by only the net benefits of TCCs (Tr. 2539) and ignores "unquantified" benefits the Company's other customers receive from TCCs in addition to the \$120 million to be imputed in the calculation of revenue requirement (Ex. 417, p.1).

On reply, the Company amplifies its contention that the "surpluses" of \$151.5 million in 2005 and \$124.5 million in 2006 are fictitious:³⁴⁹

a. The fact that congestion costs embedded in energy commodity prices paid by the Company and ESCOs serving its retail access customers cannot be separated out and quantified precisely does not render those costs "hypothetical," rather than real, anymore than the electricity costs embedded in rents of residents in master-metered buildings are hypothetical simply merely because they are not separately identified and billed.

³⁴⁸ NYC Government Customers' Reply Brief, pp. 19-20.

³⁴⁹ The Company's Reply Brief, pp. 149-51.

- b. The Company's own spot market purchases of energy amounted to about \$1.5 billion in 2005 and over \$800 million in 2006 and 2007, and are projected to be over \$1.1 billion in 2013 as the Company's firm contract obligations decline (Ex. 107, 110). ESCOs, which serve more than 60% of the Company's retail access customers, incur spot market energy costs almost certainly even higher than the Company's because they do not have the same mandated firm contract obligations and, thus, are likely to purchase more of their requirements on the spot market (Tr. 4804-05). Congestion costs have been estimated to comprise about 10% of average market energy prices in New York City in 2007.
- c. Thus, embedded congestion costs in the spot market energy purchases of the Company and ESCOs providing commodity to the Company's retail access customers more than offset the "surplus" NYPA calculates.

3. Discussion

One basic issue presented is whether the May 2000 contract between NYPA and the Company bars NYPA's enjoyment of any or all of the net rents from TCCs transferred from NYPA to the Company.

With respect to the TCCs NYPA transferred to the Company, section (I)(c)(1) of the May 2000 contract states that any rents associated with such TCCs "shall be retained by Con Edison." Section D of the same contract obliges the Company to reimburse NYPA for all associated congestion costs. A basic position of NYPA's customers is that this contract does not bar us from nevertheless allocating a portion of any such proceeds to NYPA as a matter of ratemaking. Thus, the argument continues, as NYPA is a delivery service customer that contributes to the costs of the Company's transmission system, it should receive a share of any net TCC revenues, just like any of the Company's other delivery service customers.

The effect of this proposal, however, would be to impose obligations on the Company (payment of more than NYPA's congestion costs) and to allocate benefits to NYPA and its

customers that differ materially from what NYPA and the Company agreed to expressly.

A related point is that the record as a whole suggests that when NYPA retained some TCCs and transferred others to the Company in 2000 it was hedging its bets about the future relationship of transmission congestion revenues and costs. Now that the passage of time has clearly shown that transmission congestion revenues related to the transferred TCCs always exceed transmission congestion costs on an annual basis, it is apparent that NYPA is trying to avoid the effects of a contract that might have been, but did not turn out to be, beneficial to it.³⁵⁰ We decline to interfere with the existing contract in this way.

As to the auction revenues from TCCs that were initially assigned to the Company (i.e., excluding TCCs NYPA transferred to the Company), we conclude that the terms of the May 2000 contract are not relevant for the specific purpose of determining whether NYPA should enjoy any portion of the auction proceeds as an offset to its delivery service revenue requirement. As to these proceeds, NYPA and its customers are persuasive that they are entitled to a fair share of such benefits as much as any of the Company's other delivery service customers. Stated differently, the May 2000 contract includes no terms that govern or pertain to the disposition of the Company's TCC auction revenues.

Another major issue presented, which was not a consideration in the Company's last electric rate case, concerns whether TCC auction revenues and rents, net of unbundled congestion costs, are properly seen as a "surplus" available to offset future revenue requirement for all customers receiving

³⁵⁰ NYPA's Reply Brief, p. 17, for example, describes the 2001 contract as one that benefits the Company's customers greatly to NYPA's detriment.

delivery over its system or as a partial credit of congestion costs bundled in commodity costs incurred for the Company's full service and retail access customers.

As a procedural matter, NYPA downplays this issue on the grounds that: (1) when asked by NYPA on discovery to disclose total TCC revenues and costs in past periods, the Company did not even identify congestion costs in bundled day-ahead and bilateral contract energy charges; and (2) the Company thereafter failed to quantify, even in general terms, the amount of annual congestion costs paid by its full service and retail access customers via these means.

We conclude that NYPA's procedural concerns are valid in part and overstated in part. Indeed, we believe this issue might have been eliminated in whole or in large part if the Company early on provided its best estimate of all congestion costs incurred in bundled day-ahead and bilateral contract energy purchases for its full service and retail access customers.

On the other hand, the Company fully explains why a precise calculation was not possible. It also refers to some factual information on the record (Exs. 107 and 110) necessary to estimate congestion costs in day-ahead commodity charges paid by its full service customers in past and future periods.³⁵¹

The Company also explains that 60% of its energy deliveries are to retail access customers and NYPA's witness agreed with that figure and that such costs are likely passed

³⁵¹ Ex. 361, however, is the Company's updated forecast of wholesale electricity prices by calendar year, 2009 through 2013. Its projected day-ahead spot energy costs are \$530 million in 2009 and \$384 million in 2010. This supports a Rate Year simple estimate of \$530 million (.75) + \$384.2 million (.25) or \$493.3 million of which 10% is \$49.3 million. Thereafter, its day-ahead purchases, as a percentage of total energy purchases, are expected to increase substantially.

along to ESCOs' customers. The Company also suggests it is likely that ESCOs purchase relatively more energy than it in the day-ahead spot market.

As a substantive matter, NYPA's reply brief states that energy purchases from the ISO "may" include a congestion component, implying there is some factual reason to doubt it. However, NYPA does not identify any such reasons. Moreover, NYPA's witnesses acknowledged that such costs exist (Tr. 4809) and there was no redirect examination on this point (Tr. 4818-19). A DPS Staff witness also testified that ISO energy prices comprise the marginal energy price, plus line losses, plus a congestion component.³⁵² The NYPA rebuttal testimony did not address this. The best evidence on the record is that approximately \$77.1 million of congestion costs will be incurred by ESCOs in connection with the purchase of spot market commodity for the Company's retail access customers in the Rate Year.³⁵³

Taking the \$49.3 million of projected bundled congestion costs in the Rate Year for day-ahead commodity purchases for the Company's full service customers, the \$77.1 million of projected bundled congestion costs in the Rate Year for day-ahead commodity purchases for the Company's retail access customers, and the \$120 million forecast of TCC revenues in excess of NYPA's bundled congestion costs (a large portion of which are governed by the May 2000 contract and in which NYPA should not share for reasons previously discussed), it is likely that there will be no net TCC revenues fairly allocable to NYPA in the Rate Year.

³⁵² Tr. 2531.

³⁵³ \$49.3 million of congestion costs in day-ahead purchases for the Company's full service customers divided by $[1 - .61 = .39]$ equals \$126.5 million for total congestion costs in day-ahead purchases. \$126.5 million times the ECOS' share (.61) equals \$77.1 million.

The Company also argues, and DPS Staff's testimony agrees, that the Company's full service customers also pay congestion costs in the form of Transmission Usage Charges (which include a transmission congestion cost component) when the Company purchases commodity under bilateral contracts. The record also shows that the Company has firm contracts for 3,576 MW of capacity as of March 31, 2008³⁵⁴ of which 2,136 MW or 60% are from generation facilities located upstate and for which Transmission Usage Charges must be incurred. Using this information and the Company's updated projection of firm contract "other" costs for 2009 and 2010 per Ex. 361,³⁵⁵ it is even more apparent that the net TCC revenues the Company will likely receive in the Rate Year will not in any way be "surplus" or fairly allocable in whole or in part to NYPA.

Another issue presented concerns the weight to be accorded to DPS Staff's analysis of the TCC allocation issue on a cost-of-service basis. As noted above, DPS Staff calculates that congestion revenues received by NYPA, in the period 2005 through June 2008, comprised 27% of the total and substantially exceeded that which would be due by simple application of a demand allocator in the 13.17% to 14.13% range.

This is the same basic analysis on which we relied in the Company's last case to conclude that NYPA should not share in the Company's total net TCC auction revenues and rents. It confirms that NYPA and its customers are being treated fairly. NYPA's criticism of DPS Staff's cost-of-service analysis is flawed. Even assuming NYPA should share in total net TCC revenues, something we reject above, the proper comparison that should be made with NYPA's transmission allocation factor is NYPA's percent share of total TCC benefits available from

³⁵⁴ Ex. 108.

³⁵⁵ \$89.243 million (.75) plus \$86.649 million (.25) equals \$66.93 million plus \$21.66 million or \$88.59.

auction revenues and gross rents from the transferred TCCs. The use to which recipients apply the benefits is immaterial from a cost-of-service perspective. The fact that NYPA may use the benefits to offset congestion payments while Consolidated Edison uses the benefits as a base rate offset is of no consequence. Examined in this light, it is clear that NYPA is already receiving benefits substantially in excess of the level warranted based on cost-of-service principles.

In light of our conclusions, we see no need for further collaborative discussions on this topic.

4. Revenue Allocation Treatment Resulting From A Change in Imputed TCC Revenues

The NYC Government Customers argue that the final revenue allocation decision in this case must be adjusted to reflect whatever decisions are made with respect to the allocation of net TCC revenues.

They give examples of how this would be done in different circumstances:³⁵⁶

<u>Assumption</u>	<u>Adjustment Warranted</u>
1. NYPA class allocated a fair share of TCC net revenue.	1. Reduce NYPA rates by \$17.1 million before the across-the-board or other revenue allocation is applied.
2. NYPA class allocated some but less than its fair share of TCC net revenue.	2. Reduce NYPA rates by the indicated amount before applying the approved allocation.
3. No TCC net revenue allocated to the NYPA class.	3. NYPA should absorb no share of the \$30 million revenue increase resulting from the proposal to reduce the revenue imputation from \$150 million in the Company's last case to \$120 million in this case.

³⁵⁶ NYC Government Customers' Initial Brief, pp. 59-61.

The Company, DPS Staff and NYPA agree with the NYC Government Customers.³⁵⁷

In light of our conclusion above, that none of Consolidated Edison's "net" auction proceeds or rents should be allocated to NYPA and its customers in the Rate Year, NYPA will absorb no share of the \$30 million revenue increase resulting from our adoption of a \$120 million "net" TCC revenue imputation compared to the \$150 million imputation adopted in the 2008 Rate order.

C. SC 1 Customer Charge³⁵⁸

CPB opposes the Company's proposal to increase the monthly residential customer charge from \$12.42 to \$14.90, an annual increase per customer of \$29.76. According to CPB:³⁵⁹

- a. The current monthly customer charge of \$12.42 is greater than the \$12.20 monthly cost reflected in the Company's 2005 ECOS.
- b. Contrary to the Company's proposal, it is not reasonable to assume monthly residential customer costs are now \$14.90 just because (1) the Company was granted a 12.4% overall revenue increase in the Company's last electric rate case and (2) the Company is seeking a 17.7% overall revenue increase in this proceeding.³⁶⁰

³⁵⁷ The Company's Electric Rates Panel (Tr. 1136-1137, DPS Staff witness Padula (Tr. 2589), and NYPA's Initial Brief, pp. 31-32.

³⁵⁸ In its Initial Brief (pp. 441-443), the Company summarizes all of its rate design proposals. These are all uncontested with the exception of the proposed increase in the customer charge for SC 1 and SC 7 residential/religious customers. The latter issue is discussed here.

³⁵⁹ CPB's Initial Brief, p. 13. The figures discussed are based on the Company's May 2000 revenue request.

³⁶⁰ Tr. 1077. CPB's brief does not state the dollar revenue increase it believes coincides with 17.7%, but it appears that CPB is referring to an electric delivery service percentage increase rather than an overall electric revenue percentage increase.

- c. It is more reasonable to assume that some Company costs have increased since 2005 and that others have not and, thus, the monthly customer charge should not be changed until after a new cost study is prepared.
- d. If we decide that the SC 1 and SC 7 monthly customer charge should continue to equal each other, the higher cost of service for the SC 7 class of 16,000 customers should not drive a higher than cost-of-service charge for the Company's 2.6 million SC 1 customers (Ex. 440, pp. 33-35).

The Company opposes CPB's customer charge proposal for the following reasons:³⁶¹

- a. The resulting customer charge would be below Rate Year customer costs of \$14.90.
- b. The \$14.90 cost was appropriately determined by subtracting the Billing Payment and Processing charge of \$0.94 from the SC 1 customer cost per the Company's 2005 ECOS (\$11.26), as increased to reflect the April 2008 overall revenue increase of 12.4% and the proposed April 2009 increase of 17.7%, yielding \$14.90.³⁶²

The Company's own arguments in effect concede that the current monthly customer charge (\$12.42) for SC 1 and SC 7 customers is set at a level higher than the cost of service under the 2005 ECOS. In the Company's last electric rate case, however, we held that the 2005 ECOS "is not the best source of information for purposes of setting the residential customer charges" and that a current study could safely be assumed to have presented higher cost figures.³⁶³ For that reason, we approved an increase in the residential monthly customer service

³⁶¹ The Company's Initial Brief, pp. 451-52.

³⁶² Using the same calculation method, the Company says the monthly customer charge for SC 7 would be \$16.43. Nonetheless, it believes the monthly customer charge for the SC 7 class should remain the same as that for SC 1 customers, though it would not object to setting different rates for the two classes in its next electric rate case. The Company's Reply Brief, p. 152.

³⁶³ 2008 Rate Order, p. 138.

charge in proportion to the overall electric delivery service percentage revenue increase approved in that case.³⁶⁴ There still is no more current cost of service study available. If there were, it would just as surely present higher costs for residential customer service. Applying the approach adopted in the Company's last electric rate case, the Company is authorized to increase the current \$12.42 SC 1 and SC 7 monthly customer service charges in proportion to the overall electric delivery service percentage increase allowed here.

D. BIR Proposal

The Company's Business Incentive (BIR) Rates give eligible customers discounts in order to promote economic development, with other Company customers covering some of the forgone revenues. Up to 432 MW of load is dedicated to this program and its status can be summarized as follows:³⁶⁵

	<u>TOTAL</u>	<u>UNSUBSCRIBED</u>
1. Customers Receiving a Comprehensive Package of Economic Incentives from State or Local Government	275 MW	146.1 MW
2. (a) Customers in New and Vacant Premises Receiving Tax Incentives or NYC Energy Rebates, Non-Medical	137 MW	29.1 MW
(b) Medical	20 MW	0 MW

The Company proposes to extend the program, as is, for the entire length of any rate plan adopted in these cases. No party opposes extension of the BIR program.

³⁶⁴ Id.

³⁶⁵ The Company's Initial Brief, p. 453.

Consumer Power Advocates (CPA), however, proposes in its testimony that the eligibility criteria for 1 and 2(a) above should be modified and that the 20 MW for 2(b) above be increased to 77 MW. CPA proposes the revisions because:³⁶⁶

- a. The current 20 MW set aside is fully subscribed.
- b. While manufacturing jobs are falling in New York City and Westchester County, academic research and education, areas closely related to biomedical research, are growing.
- c. Energy costs contribute significantly to biomedical research institutions' operating costs in New York and may cause research funding to shift elsewhere, particularly when State budget cuts are affecting their programs.
- d. Rules for current open BIR set-asides do not explicitly exclude non-profits, but include criteria: that require tax abatements and other benefits that do not apply to non-profits; or that allow agencies, such as New York City's, to frustrate access by withholding any "comprehensive package of benefits," which is a prerequisite for those other set-asides.
- e. Increasing the biomedical BIR set-aside to 77 MW would remedy the problem by providing an amount equal to the potential share of biomedical research employment.

The Company opposes CPA's proposed changes for the following reasons:³⁶⁷

- a. With regard to the "comprehensive package" set-aside, there is no need to add the receipt of low-cost financing as an eligibility criterion, because the current tariff language affords eligibility without the need to qualify for property tax incentives. (The same is true under the New and Vacant Buildings program.)

³⁶⁶ CPA's Initial Brief, pp. 2-3.

³⁶⁷ The Company's Initial Brief, pp. 452-458. The Company also argues against a new criterion CPA proposed in its testimony, based on level of customer investment in property relative to assessed value. CPA does not pursue this proposal on brief.

b. Concerning the proposed allocation of 77 MW for Bio-Medical Facilities:

- i. The record shows that bio-medical facilities are growing without any economic development benefits and free-ridership should not be allowed at the expense of other ratepayers.
- ii. The 2008 Rate Order rejected CPA's contention that BIR benefits should be allocated based on the number of jobs offered by an applicant. Such allocations should be based on electric load.
- iii. CPA's suggestion that biomedical facilities in New York need more incentives to compete with other regions of the nation is based on a comparison of operating costs that is incomplete and, moreover, that ignores the need for biomedical research to be conducted near superior research and business infrastructure.

In response to the Company's claims that eligibility rules under its BIR tariff are already sufficiently flexible to accommodate the nonprofit sector's needs, CPA argues that the requirement for a "comprehensive package of benefits" explicitly demands that a customer qualify for more than one benefit. All of the benefits but one--low-cost financing--are tax benefit programs, which are not applicable to nonprofits. If low-cost financing alone is a sufficient qualifying criterion, CPA says, the tariff should be amended to say that expressly.³⁶⁸

Furthermore, it maintains even that change would not sufficiently help the biomedical research sector, for which the current 20 MW set-aside is fully subscribed, because not all biomedical projects use financing for development.³⁶⁹

Inasmuch as the Company appears to concede that low-cost financing should be sufficient to qualify under the "comprehensive package of benefits" category for the BIR discount, we will require the Company, as CPA proposes, to file

³⁶⁸ CPA's Reply Brief, pp. 1-2.

³⁶⁹ Ibid., p. 2.

a revised tariff that explicitly makes that sole criterion suffice for eligibility. That change in itself should serve to expand biomedical facilities' access to the 146 MW of BIR set-aside still available in that category.

CPA argues that such a tariff revision alone is not enough, because some biomedical facilities do not use financing to develop their projects. On this record, we do not see why, if those projects do not require low-cost financing assistance as an incentive to proceed, they will not go forward without discounted electric delivery rates subsidized by other Company ratepayers. In fact, the record shows that CPA members currently have \$1.3 billion in biomedical projects under development for completion from 2009 through 2013, even without access to additional BIR set-asides (Ex. 234). In these circumstances, particularly with access to additional BIR set-aside made available to biomedical facilities in conjunction with low-cost financing, we do not find adequate justification for making an additional 57 MW of BIR set-aside available to biomedical facilities. We therefore will not adopt CPA's proposal to increase the biomedical BIR set-aside to 77 MW.

E. Shore Power Tariff

New York City and the Port Authority jointly propose that the Company be required to develop a Shore Power Tariff in a collaborative process, so that docked ships will purchase electricity from the Company instead of generating it on-board by burning oil. They support this proposal for the following reasons:

- a. Rate tariffs are typically designed for classes of customers with homogeneous service characteristics. Docked ships are not like other customers because the average load of a ship is 14 MW (very large) and shore power load follows a schedule and is highly predictable. Moreover, docked ships can rely on their own generators when the Company experiences its peak system load.

- b. The Company's current standby tariff is not appropriate for docked ships because it is designed to meet customers' needs in an unlikely event, whereas Shore Power rates could be designed for off-peak, interruptible service. Moreover, electricity under the Company's current tariff would cost a ship \$1.28 million more on an annual basis, making it unlikely that any ship owner would select this option.
- c. A Shore Power Tariff would provide the Company with an incremental stream of revenues and allow the Company to spread fixed costs over more customers. The Company does not say why it is not interested in developing this new source of revenue.
- d. A Shore Power Tariff would reduce combustion of No. 6 oil on ships and avoid significant air emissions and have positive environmental and environmental justice impacts discussed fully in EPA's comments (see below).
- e. The Company's Electric Rate Panel did not contradict the argument that the Company's standby tariff would be unattractive and conducted no study of the feasibility of a new tariff rate.
- f. The possibility that a Shore Power Tariff may be more effective for cargo ships instead of cruise ships is an issue that would be considered in the collaborative process.
- g. The Company's Electric Rates Panel does not and cannot provide any explanation of how a standby tariff rate that has failed to attract any customer meets the needs of customers.

Region 2 of the United States Environmental Protection Agency (EPA) is not an active party. However, it filed comments in support of a Shore Power Tariff.³⁷⁰ EPA comments as follows:

- a. Shore power is a crucial step for cleaning our air and improving the health of New Yorkers.
- b. Ocean-going vessels that dock in New York City typically burn high sulfur fuel in diesel engines to generate auxiliary power. This combustion results in exhaust containing NO_x, SO_x, and particulates and

³⁷⁰ EPA's arguments are also reflected in the tabulation that is Appendix II of the recommended decision, the Summary of Public Comments.

such exhaust is likely a carcinogen. A Port Authority study shows that use of Shore Power at the Brooklyn Cruise Terminal would annually eliminate 100 tons of NO_x, 100 tons of SO_x, and 6 tons of particulates.

- c. New York City's air quality is among the worst in the nation and port-related air emissions are meaningful and avoidable.
- d. Such air emissions are harmful to the public generally, and especially to children, the elderly, people with lung diseases, those who exercise outside, and low-income and minority communities located near ports.
- e. Implementation of a Shore Power Tariff is consistent with economic development in New York City.
- f. Implementation of an appropriate Shore Power Tariff in New York City would provide an impetus for ship owners to invest in ship-side Shore Power equipment and for widespread use of this technology in other ports on the east coast.
- g. None of the Company's current tariffs accurately account for the unique service characteristics of ships that dock in New York City.
- h. A rate-setting working group charged with delivering a Shore Power recommendation should be convened quickly.

The Company opposes implementation of a Shore Power Tariff for the following reasons:³⁷¹

- a. Assuming a Shore Power customer would be a retail customer of the Company -- something the Company thinks is not likely -- no showing has been made that a Shore Power customer would be any different from any other customer that would rely on the Company to back up customer-owned generation. Accordingly, the Company's existing stand-by tariff should apply. That rate includes a contract demand charge designed to recover the costs of local facilities put in place to serve the individual customer. That rate also includes an as-used demand component, for costs of facilities shared with other customers.

³⁷¹ The Company's Initial Brief, pp. 458-61.

- b. In fact, the Company has seriously considered the shore power tariff issue and tried unsuccessfully to identify customers under such a tariff. Vessels in New York City dock at Port Authority terminals, however, and the Port Authority is a NYPA customer (Tr. 1167), so NYPA, rather than the Company, will ultimately determine the rate for shore power service, including commodity supply costs.
- c. A claim that the Company's stand-by rate is not a viable economic option for ships is not a good reason to cast aside a cost-based rate. That the Company's current stand-by service tariff might be "economically unattractive" to ocean-going vessels is irrelevant, since rates are designed to recover the Company's cost of service, not to be "economically attractive." There has been no showing that other customers should subsidize service to ocean-going vessels.
- d. Even if a new cost-based rate could be developed for Shore Power, it still might not be a viable economic option because a large portion of the costs incurred by the customer will be supply-related.
- e. Studies have found that Shore Power is more viable for ships with large load factors, such as cargo ships that are in port longer.
- f. At meetings with interested stakeholders previously attended by Company representatives, the Company offered specific suggestions to reduce the difference in costs between ship-generated and shore-generated power. In this light, no need for a technical conference has been established.

The Company adds these points on reply:³⁷²

- a. External benefits that might be achieved through the proposed new shore power tariff are not relevant to cost-based rates. Moreover, the claimed benefits would not be realized when service was interrupted if, as the NYC Government Customers suggest, shore power service were interruptible.
- b. That shore power service could be interruptible is also irrelevant, because the Company must provide the same level of necessary infrastructure to serve the customer's load at any time, whether it regularly or only rarely takes standby service. In

³⁷² The Company's Reply Brief, pp. 152-55.

addition, vessels to be benefited by the proposed tariff have a very poor load factor.

- c. That the electrical requirements of a vessel exceed those of an average Company customer is irrelevant. The Company has customers with on-site generation of similar size and does not provide tariffs specially tailored to their circumstances.

The proponents of the proposed shore power tariff fail to address the Company's key point that vessels dock in New York City at terminals of the Port Authority, a customer of NYPA, which will determine the rate for service, including commodity cost. We conclude that there is insufficient justification for the proposal to require the Company to establish a shore power tariff. The interested parties should pursue this issue further with NYPA.

F. Submetering

1. SC 8 and SC 12 Customers

DPS Staff proposed that the Company be required to submit a plan for submetering, within four years, all individual living units in master-metered residential multi-family buildings with SC 8 (multiple dwellings-redistribution) or SC 12 (multiple dwelling-space heating) service (Tr. 3590).³⁷³ Buildings that failed to convert to submetering would be switched to SC 1. DPS Staff supports its proposal on these grounds:³⁷⁴

³⁷³ Under DPS Staff's proposal, the Company would have to submit an implementation plan within 60 days after an order is issued in these cases, including: a proposed mechanism to track meter installations; a plan to identify the un-metered SC 8 and SC 12 buildings; an education and outreach plan; and a plan for waivers to address individual buildings that cannot be converted because of internal building wiring or other cost prohibitive factors (Tr. 3632). DPS Staff's Initial Brief, pp. 277, 281.

³⁷⁴ DPS Staff's Initial Brief, pp. 277, 281.

- a. Commission policy since 1977 has favored increasing use of direct metering or submetering of individual living units to promote individual electricity customers paying bills directly related to their actual consumption, in order to increase efficient use of electricity and mitigate rising electric rates (Tr. 3615), further State energy efficiency goals, and reduce environmental impacts.³⁷⁵
- b. There are 455,000 unmetered individual residential units served under SC 8 and SC 12 (Tr. 3592).
- c. Building owners, not Consolidated Edison, would be responsible for wiring and meter installation costs and could participate in financial incentive and other programs available through NYSERDA to offset costs (Tr. 3596).
- d. Cost effectiveness in specific situations would be addressed through development of criteria for waivers.

The Company expresses the following concerns with DPS Staff's proposal:³⁷⁶

- a. No credible evidence was introduced to the effect that submetering would cause tenants to reduce energy usage. A program that could impose costs on the Company and many New York City building owners should have stronger support.
- b. Submetering may not be an economically efficient way to achieve energy efficiency in instances where a building is not wired in a way that lends itself to submetering. In some instances, rewiring buildings could increase electric load, by bringing wiring up to code, allowing tenants to add appliances and electronics.
- c. Unlike any other energy efficiency programs, the proposal here would be mandatory and affords no customer appreciation of the benefits of energy efficiency and of changing usage habits. The proposal is also contrary to the Commission's submetering regulations that provide for a

³⁷⁵ Citing, e.g., Case 07-E-0820, New York University – Petition to Remove Individual Apartment Meters, Order Denying Petition for Waiver (issued February 21, 2008) (Order Denying NYU Waiver).

³⁷⁶ The Company's Initial Brief, pp. 461-63.

participatory process. Moreover, the Company is placed in the unenviable position of threatening its customers with higher rates should they fail to comply timely with any new requirements.

- d. No consideration has been given to whether NYSERDA should help to fund conversions.
- e. Perhaps the issue should be transferred to the EEPS case.
- f. If DPS Staff's proposal is nevertheless adopted, the Company will need to inform customers about the initiative and provide a process for monitoring progress and granting waivers. In that event, it should be allowed to defer all the associated costs of such activities.

In response to the Company's attack on the premise that actual energy usage information on bills will give customers price signals leading them to reduce consumption, Pace counters:³⁷⁷

- a. DPS Staff's position is intuitively sound.
- b. Commission precedent and policy since 1976 strongly support DPS Staff's position.³⁷⁸
- c. The Company's contention that the effect of rewiring a building to accommodate submetering "may" increase building electrical load is what really lacks evidentiary support, despite the Company's burden of demonstrating by specific evidence the circumstances under which that would occur.

Pace also objects to the Company's suggestion that DPS Staff's proposal be moved to the EEPS proceeding, because the issue is specific to Consolidated Edison and the EEPS case should not be burdened with it, since the Company stands alone in questioning the concept that submetering promotes more efficient energy use.³⁷⁹

³⁷⁷ Pace's Reply Brief, pp. 2-4.

³⁷⁸ Citing, e.g., Order Denying NYU Waiver, pp. 2-3.

³⁷⁹ Pace's Reply Brief, p. 4.

CPA opposes DPS Staff's proposal to submeter each separate apartment, because:³⁸⁰

- a. The proposal is not founded on any estimate of its effectiveness as an incentive to conserve or of potential excessive cost impact on particular building owners or tenants (Tr. 3622). Studies offered in support fail to isolate or quantify the effectiveness of sub-metering alone.
- b. Staff failed to identify the types and numbers of buildings for which sub-metering would be more costly than average and there is no public program to provide financing for the metering change (Tr. 3618).
- c. Staff acknowledged the need to provide for waiver of the requirement, but offered no guidance on a process or criteria for waiver (Tr. 3626).

In its Reply Brief, CPA denies DPS Staff's assertion that NYSERDA funding is available to underwrite costs of submetering in master-metered SC 8 and SC 12 buildings. CPA contends NYSERDA funding is available only for use with other energy efficiency measures, not for simply rewiring to allow installation of sub-meters.³⁸¹

The Retail Energy Supply Association (RESA) makes the following points concerning DPS Staff's proposal:³⁸²

- a. RESA consistently supports Commission efforts to promote and enhance the efficient use of limited energy resources.
- b. The submetering of master-metered residential buildings would promote and enhance the efficient use of limited energy resources.
- c. However, the Company raises several reasonable concerns regarding implementation of DPS Staff's proposal.
- d. Accordingly, RESA suggests a collaborative process be initiated for further discussion on this complex matter.

³⁸⁰ CPA's Initial Brief, p. 3.

³⁸¹ CPA's Reply Brief, p. 5.

³⁸² RESA's Initial Brief, p. 4.

The Small Customer Marketer Coalition (SCMC) also supports continued discussion of this issue in a collaborative, observing that DPS Staff's proposal raises a number of logistical, administrative, legal, and financial issues that cannot be fully considered within the confines of an 11-month rate case schedule.³⁸³

In its reply brief, DPS Staff adds the following:³⁸⁴

- a. The Company's claim that DPS Staff did not provide credible evidence that SC 8 or SC 12 customers receiving usage information would change behavior is not true. DPS Staff provided testimony that NYSERDA research data show that submetering installations in apartment houses have induced individually metered and charged tenants to reduce consumption by 18% to 26% (Tr. 3595).³⁸⁵
- b. The Company itself states that even those energy consumers on its system who do not have responsibility for electric bills "should be guided by the same goal of conservation as customers" (Tr.1240-41, 1326; the Company's Initial Brief, p. 203, n.90).

The Company makes these additional points on reply:³⁸⁶

- a. Contrary to DPS Staff's claim, there are only 295,000 units in privately-owned buildings served by the Company under SC 8 and SC 12. The other 160,000 units DPS Staff includes in its figure are in publicly-owned buildings that NYPA serves, and DPS

³⁸³ SCMC's Initial Brief, pp. 2-3.

³⁸⁴ DPS Staff's Reply Brief, pp. 89-90. DPS Staff also notes its opposition to testimony by a CPA witness, seeking to exempt from the submetering proposal any building not subject to codes requiring wiring capable of supporting individual meters and any buildings used as "temporary housing."

³⁸⁵ The DPS Staff testimony actually cites NYSERDA studies as showing that usage in master-metered buildings is 18 - 26% higher than in submetered buildings (Tr.3595; Ex. 439, response to Company Interrogatory 13), which should mean that the savings in going in the opposite direction, from master-metering to submetering, would be 15 - 21%.

³⁸⁶ The Company's Reply Brief, p. 155-56.

Staff does not intend to include publicly-owned housing in its submetering requirement (Tr. 3609).

- b. Exceptions and exemptions that DPS Staff now recognizes could be the basis for waiver of the requirement for particular individual buildings -- such as inability to convert because of internal wiring or inability to complete installation within the allowed time -- would undermine DPS Staff's expectation that this submetering proposal would aid the State in achieving its 15 by 15 energy efficiency goal.

Even assuming that only 295,000 units would potentially be addressed by DPS Staff's proposal, only 15 - 21% energy savings could be expected where submetering is undertaken, and some buildings might be exempted under waivers, the proposal does offer the prospect for substantial benefit toward achieving State energy efficiency goals. Still, significant questions remain with respect to the proposal, such as the availability of NYSERDA funding, circumstances that would warrant waiver or exemption, lack of input and participation of master-metered building owners and tenants on potential problems or concerns with submetering and the conversion process, the time that should reasonably be allowed for conversion to occur before building owners and tenants might be faced with a shift to SC 1 for failure to convert, and whether potential overall benefits from the proposal are likely to outweigh potential detriments. We believe this proposal remains too nascent and general at this point and requires further development before submission for our specific consideration. Transfer of the matter to the EEPS proceeding is not desirable. That proceeding is sufficiently complex already without adding this proposal to it.

The suggestion of RESA and SCMC to establish a collaborative to examine development of a more refined proposal is reasonable. We will require a collaborative process to consider development of a specific proposal for submetering

living units in master-metered residential multi-family buildings with SC 8 or SC 12 service. In establishing the collaborative process, DPS Staff and the Company should identify representatives of building owners and tenants and other stakeholders who would be affected by such conversions. Those entities should be invited to participate in the effort.³⁸⁷ This submetering collaborative should consider any action we take in Cases 08-E-0836 et al.,³⁸⁸ as well as our continuing initiative on amendments to submetering regulations.³⁸⁹ In addition, the collaborative should consider the issues identified above (availability of NYSERDA funding, circumstances that would warrant waiver or exemption, etc.) and the appropriateness of submetering where tenants may not have an opportunity to install measures to manage their energy use effectively.

2. Dormitory Submetering

CPA proposes that academic institution dormitories (specifically, New York University (NYU) dormitories) with multiple individually-metered apartments on separate accounts, now billed at SC 2 (General Small) rates, be treated as residential accounts and allowed to convert to billing at residential rates as a single master-metered account under SC 8, without submetering, because:³⁹⁰

³⁸⁷ Inasmuch as an additional 160,000 master-metered units are said to be in public housing facilities served by NYPA, public housing authorities and NYPA should also be invited to participate in the collaborative.

³⁸⁸ E.g., Case 08-E-0836, Frawley Plaza, LLC - Submetering, Order Staying Order Granting Permission to Submeter (issued February 12, 2009) and Confirming Order (issued March 12, 2009). Similar stay and confirming orders were issued in Cases 08-E-0837, 08-E-0838, and 08-E-0839 on the same respective dates.

³⁸⁹ Case 08-M-1274, Electric Submetering Regulations, 16 NYCRR Part 96.

³⁹⁰ CPA's Initial Brief, pp. 3-4.

- a. Individual metering and billing do not promote energy efficiency, because an individual university itself must pay the bills and only it can enjoy any efficiency savings.
- b. Billing temporary student residents is not feasible, and, even if it were, they would not invest in efficiency measures that could not be recovered during their short-term residency.
- c. Single-account billing and large-volume demand rates would give universities the price incentive to invest in efficiency measures and to manage peak loads.

DPS Staff argues against the CPA proposal on the grounds that:³⁹¹

- a. CPA repeats an argument that NYU is responsible for payment of individual direct meter billings, which was unpersuasive when the Commission rejected a waiver request by NYU in Case 07-E-0820.³⁹²
- b. CPA's claim that having students as customers of record is administratively burdensome for Consolidated Edison is also without support in the record (Tr. 3514-15).
- c. CPA's proposal to allow dormitories to be served under SC 8 is an attempt to avoid the prohibition in SC 9 of master metering dormitories with self-contained individual living units.
- d. The Order Prohibiting Rent Inclusion of Electricity is applicable to individual living units leased by students as well as non-students. Educational institutions and owners of new dormitories have developed submetering plans that address CPA's concerns and were approved by the Commission.³⁹³
- e. Submetering NYU's dormitory would allow NYU to obtain the more favorable SC 8 rate (subject to Commission approval of submetering), but NYU and CPA

³⁹¹ DPS Staff's Initial Brief, pp. 281-284.

³⁹² Order Denying NYU Waiver, supra.

³⁹³ Citing Case 08-E-0390, United Development Corporation - Submetering, Untitled Order 1 (issued June 26, 2008)(Untitled Submetering Order 1), pp. 3-4; United Development Corporation - Submetering, Untitled Order 2 (issued September 17, 2008)(Untitled Submetering Order 2), p. 3.

do not seem to have investigated that approach (citing Order Denying NYU Waiver, supra, p. 4).

CPA denies that the Order Prohibiting Rent Inclusion of Electricity is applicable to its proposal, apparently on the ground that order did not apply to "temporary" residents, occupying living units without leases for less than one year.³⁹⁴

CPA's proposal is intended to benefit NYU and could be viewed as a minor variation on NYU's own petition that we rejected in our recent Order Denying NYU Waiver, of which NYU did not seek rehearing or reconsideration.³⁹⁵ In any event, the issue is essentially the same: whether to permit master metering in certain multi-unit residential buildings without submetering of individual units. In the Order Denying NYU Waiver, we made quite clear that the policy the Commission established in 1976--requiring individual metering of residential living units in buildings in which the internal wiring was installed after January 1, 1977³⁹⁶--remains in effect and its goals of reducing environmental impacts and improving energy efficiency are even more important today.

Individuals have little incentive to reduce their consumption unless they are aware of their kilowatt hour (kWh) consumption and are responsible for the actual costs of that consumption. Individual metering of living units directly addresses this problem and is critical to meeting the goal of reducing New York State's

³⁹⁴ CPA's Reply Brief, p. 5.

³⁹⁵ Whether the dormitory involved in Case 07-E-0820 is one of those for which CPA expresses concern here cannot be determined from the record. There might also be dormitories other than just those owned by NYU to which the proposal here, if approved, would apply. In addition, CPA's proposal here would qualify NYU dormitories only for SC 8 rates, which are higher than the SC 9 rates that were the subject of Case 07-E-0820. These differences are immaterial.

³⁹⁶ Case 26998, Proceeding of the Commission as to Rent-inclusion and Sub-metering for Electricity, Opinion No. 76-17 (issued August 16, 1976).

demand for electric power by 15% from forecasted levels by 2015.³⁹⁷

We rejected the argument, which CPA repeats here, that the policy should not apply because all electric bills for living units in the dormitory would be paid by NYU and not the residents.

This is contrary to our policy and the public interest. Removal of Con Edison's meters in each apartment and the master metering of the building would be a step in the wrong direction. Since the Dormitory is directly metered by Con Edison, students could be responsible for their electric consumption and become active participants in the effort to conserve electricity and protect our environment.

While it is the University's decision as to whether it will include electricity as part of room and board, in light of the important public policy considerations discussed above we encourage it to reconsider its policies so that students are able to participate in the State's effort to reduce electric consumption and protect our environment, especially in dormitories with directly metered living units. Even if the University continues its policy of including electricity as part of room and board in directly metered dormitories, the meters could be used to inform the University of high consumption in particular units and facilitate efforts to reduce consumption in those units. NYU could play an important role in educating future electric customers about energy conservation.³⁹⁸

Our order in Case 07-E-0820 is dispositive here. CPA's argument that the prohibition in Opinion No. 76-17 does not apply to "temporary" residents is unavailing. Nothing in our order suggests that it does not apply to units for "temporary" residents of any kind, nor has CPA cited any authority for its position. CPA's argument that billing individual student residents of dormitories is not feasible is

³⁹⁷ Ibid., p. 3.

³⁹⁸ Ibid., p. 4.

not credible, inasmuch as other educational institutions seem to be able to accomplish that feat in instances involving approved submetering.³⁹⁹ We reject CPA's proposal.

G. Geography-Based Delivery Rates

Westchester proposes that we require the Company to conduct a study of whether geography-based electric delivery service rates are warranted to reflect cost disparities between serving customers in the County and serving customers in New York City.⁴⁰⁰ Westchester argues that the Company and New York City have been strong proponents of geographic equity in recent filings on Renewable Portfolio Standard issues. It also contends that, through projects such as the East River Repowering Project (ERRP), off-shore windmills, and joint steam-electric projects the City advocates at Hudson Avenue and Hudson Yards, the Company seeks to make Westchester subsidize the cost of Consolidated Edison facilities specifically intended to serve New York City itself. Finally, the County maintains that the tax burden imposed by New York City is disproportionately higher than that imposed by the County.⁴⁰¹

The NYC Government Customers observe that the County's reference to other parties' support for fair allocation of surcharges, such as for the Renewable Portfolio Standard, is irrelevant to the issue of whether the Company's delivery

³⁹⁹ Untitled Submetering Order 1, supra, pp. 3-4, and Untitled Submetering Order 2, supra, p.3. CPA had also suggested in testimony that master metering of NYU dormitories would in some unexplained way facilitate connection of a dormitory with an NYU combined heat and power (CHP) plant in the future. The nexus between the claimed need for master metering and the ability to connect with the CHP plant is unexplained. In any event, CPA does not include the argument on brief.

⁴⁰⁰ Westchester's Initial Brief, pp. 23-26.

⁴⁰¹ The County also presented testimony making other arguments, which it does not pursue on brief. Those arguments and other parties' responses to them will not be considered further.

service rates should be geographically based.⁴⁰² That observation is correct. Support by any particular party for geographic equity *per se* has no probative value concerning whether a study of the need for rates in Westchester separate from those applicable in New York City is in order.

The County's reference to Company or New York City support for potential future off-shore windmill projects or joint steam/electric projects is also entirely irrelevant. Off-shore windmill projects might or might not ultimately be developed. A potential Hudson Avenue cogeneration facility is subject to further study and options have not been determined yet.⁴⁰³ Incipient, merely possible projects like these have no bearing on the Company's current or Rate Year costs, rates, or revenue allocations or whether there is any need for geographical distinction between rates applicable in Westchester and in New York City. The County will presumably have an opportunity to participate in whatever future regulatory proceedings might occur to consider such projects.

Nor do Westchester's allusion to the ERRP and suggestions that the Company's electric system subsidizes its steam system to the benefit of New York City and the County's detriment provide support for its call for a study of the need for geographic distinction in delivery rates. Just last September, in the 2008 Steam Rate Order, we most recently considered and explained our rejection of the County's arguments on the Company's electric system subsidizing the steam system.⁴⁰⁴ In addition, that same order approved a cost allocation study for the ERRP, to be filed by April 30, 2009. Thus, the issue of

⁴⁰² NYC Government Customers' Reply Brief, p. 21.

⁴⁰³ See Case 07-S-1315, Consolidated Edison Company of New York, Inc. - Steam Rates, Order Establishing Rate Plan (issued September 22, 2008)(2008 Steam Rate Order), pp. 37-38.

⁴⁰⁴ 2008 Steam Rate Order, pp. 39-41.

ERRP cost allocation is now under consideration in a separate proceeding.⁴⁰⁵

To the extent the County argues that the ERRP costs properly allocated to the Company's electric system benefit New York City disproportionately, that contention also fails. The Company has provided persuasive evidence that its electric system throughout New York City and Westchester is operated on an integrated basis, with facilities designed to minimize costs and further reliability and efficiency throughout its service area on an integrated basis, and that facilities in New York City benefit Westchester and facilities in Westchester benefit New York City (Tr. 4181-84). The County has not challenged that evidence, except indirectly in testimony of its witness panel that limited transmission import capability into New York City and double contingency criteria claimed to be almost exclusively applicable to Manhattan and not at all to Westchester increase electric system costs (Tr. 4647-48). These factors are not new developments, but have been aspects of the Company's electric system for many years. The County's panel itself noted that the double contingency criteria date back to the early 1960s (id.). In determining several years ago that there was no need for the Company to incur the effort and cost of a study of whether differential electric delivery rates should be developed for New York City and the County, the Commission noted that there had been no significant changes to the basic system design since the 1980s that would affect that issue or provide any basis for assigning delivery costs any differently.⁴⁰⁶

⁴⁰⁵ Case 09-S-0029, Consolidated Edison Company of New York, Inc. - Steam Planning.

⁴⁰⁶ Case 00-E-1208, Consolidated Edison Company of New York, Inc. - Plans for Electric Restructuring with respect to Service Provided in Westchester County, Order Adopting Staff Proposal (issued November 25, 2003), p. 23.

The Company and NYC Government Customers, on the one hand, and Westchester, on the other, make several arguments about the comparative burdens that New York City or County taxes contribute to the Company's electric delivery system costs.⁴⁰⁷ The points are immaterial. The property taxes are imposed on facilities and land held and used for the Company's electric delivery service and thus an ancillary cost of having and using the property for that purpose. It is already established above that the Company operates that system on an integrated basis for the benefit of both New York City and Westchester. Thus, whatever taxes are imposed by either New York City or Westchester are costs incurred for the benefit of Westchester as well as New York City customers and any differential that might exist has no bearing on whether there should be a rate differential between New York City and the County.

For these reasons, we do not adopt Westchester's proposal for a study of geography-based electric delivery service rates.

H. Electronic Tariff

DPS Staff proposes that Consolidated Edison be required to submit a plan for converting its electric service tariff leaves to an electronic format using the Department of Public Service Electronic Tariff System (ETS). The plan would include identification of steps needed to convert the Company's electric service tariff schedules to ETS format, identification of any potential difficulties with conversion, incremental cost estimates, and a schedule to complete transition within three

⁴⁰⁷ Westchester's Initial Brief, p. 25; Westchester's Reply Brief, p. 13; the Company's Initial Brief, p. 465; NYC Government Customers' Initial Brief, p. 71; NYC Government Customers' Reply Brief, p. 23.

years (Ex. 429, Testimony, p. 5-6). DPS Staff justifies the proposal on these grounds:⁴⁰⁸

- a. Nearly 10 years ago, the Commission stated that ETS will not reach its maximum effectiveness until it contains all utility tariffs and that the Commission expected an orderly transition of all tariffs to ETS.⁴⁰⁹
- b. All major gas utilities, including Consolidated Edison, have converted to ETS, as have all major electric utilities except Consolidated Edison and its Orange and Rockland affiliate (and National Grid, which has just one tariff left to convert to ETS).
- c. The Company's claim that its electric service tariffs are significantly larger than other companies' is not true.
- d. The Company's claim that conversion is a complex process is not credible in light of other utilities' successful conversion.
- e. The electric tariff on Consolidated Edison's web site does nothing to relieve the inefficiencies of the manual paper tariff filing process with the Department of Public Service. The tariff on the Company's website also provides no advantage over ETS and searching the Company's entire website tariff by word or phrase is very difficult.
- f. ETS also provides a number of other efficiencies and advantages for filing and searching, to the benefit of regulatory activities and public access.
- g. The Company's estimate of conversion cost, which amounts to \$260 per page (Tr. 1100), appears to be excessive and fails to account for any offsetting cost savings.

The Company opposes DPS Staff's proposal because:⁴¹⁰

- a. The Company's tariff is already available on its website and provides current and historical rate and

⁴⁰⁸ DPS Staff's Initial Brief, pp. 285-88.

⁴⁰⁹ Case 97-M-0508, Proposed Amendments to Commission Rules and Regulations, Memorandum and Resolution Adopting Regulations to Permit the Electronic Filing of Tariff Schedules (issued February 1, 1999), p. 12.

⁴¹⁰ The Company's Initial Brief, pp. 466-467.

tariff information in a user-friendly format to the same audience as the DPS web site.

- b. The Company is not aware of any customer complaints about its tariff not being available in the ETS format.
- c. The Company's web site allows one to access information by tariff section, subject, or leaf. The DPS site groups tariff leaves randomly.
- d. The Company is willing to make further enhancements to its web site to allow tariff filings to be listed chronologically, along with a description of each filing.
- e. Converting the Company's tariff to the ETS format is complex, time-consuming, and costly and no adequate justification has been provided given that the information is already available on the Company's web page.
- f. The Company estimates it would cost it about \$200,000 to make the conversion, excluding employee benefits. These costs should be recovered in rates, it says, if DPS Staff's proposal is to be adopted over its objection.

The Company's position is unconvincing. The Commission's February 1999 order in Case 97-M-0508 recognized the need for a period of co-existence for paper and electronic tariffs, to allow for an orderly transition to electronic and elimination of paper tariffs.⁴¹¹ The Company has had more than ten years now to prepare for converting its tariff leaves for use with the Commission's ETS, however, far more than necessary for it to be prepared for an orderly transition. In addition, DPS Staff's proposal would allow the Company yet another three years to complete conversion. The Company has no good excuse for failing to do so.

The tariffs available on the Company's website are not a substitute for tariffs available electronically through the Department of Public Service (DPS) website, as all other utilities' tariffs except the Company's Orange & Rockland

⁴¹¹ Case 97-M-0508, supra, p. 12.

affiliate's soon will be. Availability on the Company's website does not satisfy our desire for improving public access to tariffs through one-stop research and comparison ability through the DPS website or for greater efficiency for tariff processing and management internally at the DPS. DPS Staff correctly discounts the Company's claims that its tariffs are long and complex, pointing to the facts that there are longer tariffs already in ETS and other companies have managed to convert complex tariffs. The Company has already converted its gas tariffs to ETS. Moreover, the Company has had longer than other utilities to prepare for conversion of its electric service tariff schedules. The issue of conversion cost is premature at this time, because the DPS Staff proposal calls for cost estimates to be included in the plan to be considered. In any event, without more basis than what the Company has provided on the record here and an actual schedule for conversion, the Company's Rate Year costs for any conversion are speculative and might not occur at all. It is time for the Company to make plans to convert its electric service tariff schedules fully to ETS format within the next three years. We adopt DPS Staff's proposal.

I. Unbundling Delivery Rates

In its initial brief, the Company calls attention to the fact that it is actively considering whether to file for a transmission rate increase with the Federal Energy Regulatory Commission (FERC), the first such filing in more than ten years. Should it do so, any rate increase allowed by FERC could not be effectuated unless and until the Company re-filed its New York rates, removing or unbundling transmission costs. It argues that such unbundling is occurring elsewhere in the country and may be in the public interest. The Company intends to consult with DPS Staff before moving forward on any departure from the current method of bundling transmission and distribution

delivery rates in its New York tariffs. We note that the Company has identified this issue for information only. No Commission action is necessary at this time.

J. Make-Whole

As discussed in the procedural history, we accepted the Company's offer to extend the final suspension date from April 5, 2009 to April 30, 2009, conditioned on the Company being made whole for incremental revenues forgone in the period April 6, 2009 through April 30, 2009.⁴¹² The Company's proposal at the time was that incremental revenues forgone by it in the period April 6 through April 30, 2009, would be recovered, with interest, over the 23-month period ending March 31, 2011. The underlying premise is that neither the Company nor ratepayers would be any better or worse off than if there had been no extension of the final suspension date. We agree with these aspects of the Company's proposal as well. Given that the amount the Company is owed will be known by the end of this month, that the recovery will extend beyond the Rate Year, that the Company may accrue interest at its pre-tax rate of return, and that this will more likely result in long-term financing, the make-whole will be implemented as set forth in an ordering paragraph below.

K. PSL §18-a(6) Assessment

Chapter 59 of the Laws of 2009 established a Temporary State Energy and Utility Service Conservation Assessment (Temporary Assessment) applicable to public utility companies. The April 1, 2009 effective date imposes an obligation on the Company to pay in full, on September 10, 2009, the Temporary Assessment for the 2009-2010 State fiscal year. Any delay in allowing recovery would result in a significant buildup,

⁴¹² Case 08-E-0539, Untitled Order (issued February 17, 2009).

possibly necessitating a spike in customers' bills. Accordingly, we are establishing requirements for the recovery of the Temporary Assessment on the Company, pending any refinements that might be applied prospectively based on the outcome of an ongoing generic proceeding.⁴¹³

The calculation of the Temporary Assessment requires the Company to add estimated energy service company (ESCO) revenues to its own revenues to arrive at the total revenue base subject to the Temporary Assessment percentage.⁴¹⁴ The Company shall estimate ESCO revenues by multiplying the known amount of kilowatt hours delivered to ESCO customers by the commodity/supply price levied by the Company for sales to its own bundled customers. We estimate that the change in the assessments will result in an annual incremental revenue requirement above what is currently in base delivery rates of approximately \$198 million.

The current level of assessment cost recovery in base rates shall continue and the Temporary Assessment amount shall be recovered by separate surcharge. The surcharge shall be allocated to each customer class based on the class contribution (delivery and supply charges of the class)⁴¹⁵ to the Company's total electric revenues, including delivery and supply charges. The amount allocated to each class shall be collected by applying a ¢/kWh or \$/kW (depending on the specific rate class)

⁴¹³ Case 09-M-0311, Implementation of Chapter 59 of the Laws of 2009, Establishing a Temporary Annual Assessment Pursuant to PSL §18-a(6).

⁴¹⁴ The amount of the Temporary Assessment will be decreased by the amount designed to recover the Department of Public Service's costs (the Standard Assessment).

⁴¹⁵ For the NYPA and EDDS classes, only delivery charges shall be used.

surcharge to the delivery rates billed by Consolidated Edison.⁴¹⁶ This rate design will keep the overall bill impact to approximately 1.8%, which is consistent with the intent of the assessment (to have a total assessment of 2.0% on total bills).

Given that the amount of the assessment is not under the Company's control, the amounts collected through the surcharge shall be subject to an annual reconciliation.

The Company is authorized to implement the surcharge effective May 1, 2009, using an estimate of the surcharge amount of \$198 million, to be collected over the subsequent twelve-month period.⁴¹⁷ The assessment surcharge should initially be included in the total delivery charges of each customer's bill. Effective June 1, 2009, or as soon thereafter as all requisite bill system programming requirements can be met, the surcharge amount shall be delineated separately on each customer's bill.

The Company is directed to file an updated assessment surcharge calculation amount with the Secretary within thirty days of this order's issuance. The update shall be based on the Company's April 6, 2009 filing, but include its most recent inputs for working capital, ESCO commodity prices, and delivery revenues. This will be used to facilitate assessment billing of the Company.

To the extent actual sales vary from the forecast underlying rates set here, the difference shall be reconciled by adjusting the assessment surcharge in the subsequent year once the actual difference is known.

⁴¹⁶ For the NYPA, EDDS, and S.C. 13 classes, the assessment surcharge can be recovered by applying a fixed total dollar surcharge per month, since these classes appear as a single customer to the Company.

⁴¹⁷ On April 6, 2009, the company estimated the annual revenue requirement effect to be \$200 million. This shall be adjusted to \$198 million to reflect exclusion of the EDDS supply revenues from the assessable revenue base as such customers receive their supply from NYPA.

XI. OTHER ISSUES

A. Performance Metrics

1. Reliability Performance Mechanism

a. Introduction

The Company is currently subject to a Reliability Performance Mechanism (RPM) that has been developed over a period of years. The mechanism in effect today focuses on the extent to which the Company does or does not meet criteria for overall reliability, using the frequency and duration of outages on its network and non-network (or radial) systems and numbers of major outages; remote network monitoring system performance; service restoration; and program specific standards for the timely replacement of damaged poles, the removal of temporary shunts, the repair of street lights, and the replacement of over duty circuit breakers. With the exception of the service restoration metric, portions of the Company's revenues will be forgone by it to the extent the specific criteria are not met in any calendar year and any applicable exclusions do not apply. The Company's maximum annual revenue exposure under the current RPM is \$112 million.

b. RPMS in General

At a very basic level, the Company opposes any application of an RPM. It argues that such a mechanism is unnecessary, given its internally driven interest in providing good service and the significant financial exposure that exists after outages, including any costs of repairs that are not recovered in rates, payments for perishables and damaged property, and any disallowance pursuant to a prudence determination. It asserts, moreover, that revenue disallowances have the effect of depleting resources that would otherwise be used for the benefit of its customers.

DPS Staff disagrees, arguing that an RPM complies with a 1995 decision by this Commission that so long as there are no competitive alternatives to a utility's delivery service, there must be clearly defined consequences for a utility's failure to provide adequate service (Tr. 3586).⁴¹⁸ DPS Staff contends as well that revenue adjustments under the RPM are separate from and unrelated to funds used to address system needs (Tr. 3536) and that the RPM has improved the Company's overall reliability and benefited customers over time (Tr. 4147). DPS Staff denies that claims against the Company related to outages are a substitute for an RPM, on the ground that the consequences of such exposure are not definite and have no relation to an RPM. The NYC Government Customers agree with DPS Staff's arguments.⁴¹⁹

If we decide that it is essential for the Company to remain subject to an RPM, the Company's first alternative argument is that it should be afforded a reasonable opportunity to address any reliability concerns before any of its revenues would be at risk. Under the process it envisions, the Company would be informed if we have any reliability concerns, the Company would develop a plan to address the concerns, DPS Staff would monitor the Company's progress over a reasonable period of time, and the Company's revenues would be put at risk thereafter only if our concerns were not adequately addressed without a good reason. (In other words, the Company wants to eliminate the automatic nature of the existing RPM.) The Company

⁴¹⁸ DPS Staff's Initial Brief, p. 291, citing Case 94-E-0952, Competitive Opportunities Regarding Electric Service, Opinion and Order Adopting Principles to Guide the Transition to Competition (issued June 7, 1995).

⁴¹⁹ NYC Government Customers' Reply Brief, pp. 25-27.

maintains there are many instances in which it improved its performance in targeted areas without resort to an RPM.⁴²⁰

The Company notes that while it does not agree that a service restoration metric should be part of an RPM (an issue discussed separately below), it finds support for its first alternative proposal to the extent the service restoration metric was adopted without any of its revenues being placed at risk for an initial period.

In its reply brief, DPS Staff contends:⁴²¹

- a. The Company's exposure to reimbursement claims by customers is no substitute for the RPM because:
 - i. There have been many years when the Company was exposed to adjustments under the RPM, without being exposed to reimbursement claims or exposure to prudence inquiries.
 - ii. Reimbursement and loss claims provide compensation only to individual customers and only in response to specific claims, while credits from operation of the RPM offset rates generally.
 - iii. Prudence inquiries are associated with how a company operates its system and need not be associated with any RPM component.
- b. The approaches supported by the Company fail to do what the RPM does effectively, which is to hold shareholders accountable for system reliability, which is affected by a mix of different programs affecting rates. The Company has control over its performance and should be held accountable.

⁴²⁰ The Company's Reply Brief, pp. 158-59. An example is the Company's implementation of 87 recommendations set forth in DPS Staff's 2007 report concerning the 2006 Long Island City outage. It says these are being implemented without any Company revenues being at risk automatically. (The distinction is a fine one, however, as we are required to consider in major rate cases a utility's compliance with its most recent audit recommendations. Public Service Law (PSL) §66(19)).

⁴²¹ DPS Staff's Reply Brief, pp. 90-91.

We reject outright the Company's proposal to eliminate or reduce the effect of the Reliability Performance Mechanism that applies to it. The identification of performance criteria and specific consequences for failure to meet those criteria help to focus management attention on the provision of reliable electric service. The fact that the Company might have to pay food spoilage costs in certain circumstances could reasonably be a consideration in determining the amount of revenues to be put at risk, but is not a valid reason to eliminate an RPM. Revenues at risk under the RPM could also be considered in any case in which the prudence of the Company's past actions is under review, when ascertaining the appropriate ratemaking consequences of any imprudent Company acts. Again, however, this argument is not a valid basis to eliminate an RPM.

The Company's claim that it has adequate incentives to provide reliable service without an RPM is also belied by past experience. The four program standards, for example, were adopted in 2005 because the Company had failed to provide reliable service in each of the pertinent areas even after numerous complaints were brought to its attention.⁴²² Likewise, to the extent that the Company has experienced revenue disallowances from the RPM in the past, this confirms that the Company's internal incentives alone are not adequate.

The record in this proceeding with respect to the Company's failure to fill funded positions, its incentive compensation proposals, and the tremendous emphasis the Company places on the "headline" rate of return are also good reasons to believe that the Company is heavily focused on earnings and as a result indicates that financial incentives related to the provision of safe and adequate service are likely to achieve their intended results.

⁴²² Tr. 3536-37.

Another Company argument is that an RPM is not necessary on the grounds that it frequently adopts audit recommendations without any of its revenues being placed at risk. However, management audits are not conducted frequently⁴²³ and their recommendations are commonly focused on improving operations and performance. As noted above, moreover, compliance with management audit recommendations is supposed to be considered automatically in all major rate cases. The RPM (and Customer Service Performance Index Mechanism discussed below) are aimed at maintaining reasonable quality service levels that the Company has been able to maintain in the past. This Company argument is rejected.

c. Frequency and Duration of Outages

(i) The Arguments

The next issue presented concerns whether and, if so, how the existing criteria for the frequency (System Average Interruption Frequency Index, or SAIFI) and duration (Customer Average Interruption Duration Index, or CAIDI) of outages should be modified for the Rate Year.⁴²⁴

The Company and DPS Staff agree that the current SAIFI and CAIDI criteria for the Company's radial service need not be changed. These parties disagree, however, about what should be done about SAIFI and CAIDI for the Company's network service.

Both agree that the Company has a new outage management system, called STAR (System Trouble Analysis Response), that records more accurately than the Company's legacy system the start time of an outage and that predicts a

⁴²³ As discussed elsewhere in this order, PSL §66(19) calls for such audits every five years.

⁴²⁴ SAIFI equals the number of customer outages in a year divided by the total number of customers. CAIDI equals the total customer outage duration hours in a year divided by the number of customers interrupted that year.

greater number of customers will be affected by an outage as compared to the Company's legacy system.

Both agree as well that the effect of the new system is that with absolutely no change in the level of reliability, STAR results will suggest a change in reliability when compared to the legacy system's results. An important factor here is that studies prepared by the Company in 2008 and 2007 (Exs. 316 and 317, respectively) both suggest network SAIFI results will be approximately 167% to 175% higher with no change in reliability and that network CAIDI results will be approximately 25% to 41% higher with no change in reliability.⁴²⁵

Based on these study results, and some support for STAR-based change to SAIFI and CAIDI in the recommended decision in the Company's last electric rate case, the Company proposes that network SAIFI be increased from .015 to .022 (a 46.66% increase) and that network CAIDI be increased from 3.74 to 4.61 (a 23.26% increase).

As to the Company's proposed network SAIFI increase, DPS Staff is leery of the quality of the data underlying the proposal, arguing that it is basically the same as what had been provided in the Company's last electric rate case, at which time a similar proposal was rejected. DPS Staff also suggests there is not enough experience with the new STAR system to warrant such a significant increase in SAIFI, suspecting that more might be going on than the change to STAR and that more time will clarify things. DPS Staff proposes instead that network SAIFI be suspended temporarily, with two interim alternative measures adopted, including (a) Network Interruptions, and (2) Summer Feeder Open-Autos (Tr. 3545). These are measures that are indicative of reliability, that have been tracked for a long time, and that are not affected by the use of the STAR system.

⁴²⁵ The Company's initial brief focuses much more on the SAIFI results.

DPS Staff proposes no change in network CAIDI, arguing that an assessment of network frequency is independent of network duration, that network duration is greatly affected by manual interventions required before the Company had STAR (Tr. 3538), and that an increase in customer outage numbers from STAR can reduce network duration performance level and make it easier for the Company to meet the existing duration target. DPS Staff also argues that the Company failed to produce any concrete evidence that a 25% increase in the indicated duration of outages is due solely to STAR.

The Company counters along these lines:⁴²⁶

- a. The Company's proposed adjustments to the frequency and duration targets are intended to reflect the impact of the STAR system and are based upon studies of the actual differences between results of its legacy and STAR systems recorded during 2007 and 2005. The actual results agree closely with the differentials predicted by the study model (Ex. 316).
- b. DPS Staff's claim--that manual intervention creates doubt about the differential between the legacy and STAR system results for the duration standard--is off target because manual adjustment is not new to STAR, but was used with the legacy system, as well; and, in fact, to a greater degree (Tr. 4402).
- c. DPS Staff is inconsistent to rely on the Company's study results for purposes of concluding that the existing network SAIFI criterion should be abandoned while ignoring the results of the same studies suggesting that the current CAIDI criterion is also problematic, albeit not to the same degree as for SAIFI.
- d. While the Company believes that a change in network SAIFI and CAIDI is most appropriate under all of the circumstances, any decision to abandon network SAIFI temporarily should be matched by a decision to abandon network CAIDI temporarily. Specifically, CAIDI should be replaced with a "Network Outage

⁴²⁶ The Company's Initial Brief, pp. 475-82 and the Company's Reply Brief, pp. 161-67.

Duration" metric that would operate in parallel with the "Network Interruption" criterion that DPS Staff supports in lieu of SAIFI.

- e. As to DPS Staff's support for a Network Interruption criterion of 5,700 outages per year as a partial substitute for SAIFI, the Company argues this proposal does not adequately account for differences in the number of customers served per network. It argues this metric should measure network outages per customer (Tr. 4112).
- f. As to DPS Staff's support for a Summer Feeder Open Automatic criterion of 650, excluding those from major outages, the Company argues this is not a reasonable partial substitute for SAIFI because its networks are designed so that the loss of up to two feeders should not have any impact on customers. The focus, it says, would more properly be on the concentration of feeder open automatics per network. Moreover, according to the Company, DPS Staff's figure is erroneously based in part on an historic average that includes radial feeders and the latter is not a proper basis for a network reliability metric.
- g. Given that it is clear that the existing SAIFI and CAIDI are suspect for network service, any decision with respect to them for calendar 2009 should apply as well to calendar 2008.

A related issue is whether the amount of revenue at risk for failure to meet a frequency or duration criterion should be a lump sum, regardless of the extent of deviation from that criterion, or a sum that grows incrementally up to a fixed cap, the greater the deviation from the objective criterion. This issue is broached with respect to both network and radial criteria. For the following reasons, the Company argues in support of the latter approach:⁴²⁷

- a. Under the current RPM, outages from major events are not counted in assessing the frequency and duration of outages.
- b. However, even ignoring major events, weather and other variables beyond the Company's control have a

⁴²⁷ The Company's Initial Brief, pp. 482-484 and 486-487.

significant impact on the frequency of outages and Company revenues should not be at risk based on these variables. A Company study of the impacts of weather, for example, shows that the standard deviation of outages around an average during inclement weather⁴²⁸ is five times greater than the standard deviation of outages around an average in good weather. Other variables include the Company's inability to make repairs because of parked vehicles, disconnections ordered by any fire department, Mylar balloon contacts with overhead lines, and pole damage resulting from motor vehicle accidents.

- c. Likewise there is significant volatility in the duration of outages from year to year and the average duration of outages can actually be longer with major events excluded.
- d. Under the current RPM, the revenues forgone by the Company for failure to meet an objective criterion are precisely the same regardless of the extent to which the criterion is missed. Thus, a de minimis change in reliability can have a significant revenue impact. Moreover, in situations where one objective criterion is missed in a calendar year, the Company is provided a financial incentive to put its resources into making sure all other performance criteria are met rather than devoting resources to the problems that resulted in the Company missing the first criterion.
- e. As a matter of principle, the judges in the Company's last electric rate case agreed a change along these lines might be in order.

In light of these contentions, the Company proposes that none of its revenues be at risk when the actual frequency or duration of outages falls within one standard deviation of the historic mean, that \$1 million be at risk for actual results falling between one and 1.5 standard deviations above the historic mean, that an incremental \$2 million be at risk when actual results fall between 1.5 and two standard deviations above the historic mean, and that an incremental \$3 million be

⁴²⁸ Caused by falling limbs, lightning, water intrusion, ice accumulation, and corrosive salts.

at risk when actual results exceed two standard deviations, or the upper end of the 95% confidence level, above the historic mean.⁴²⁹ Thus, the Company's revenues would not be at risk in circumstances where it believes there is a significant chance natural weather variability is at fault and revenues at risk would grow gradually to the extent it is more likely the Company rather than the weather is at fault for the outages.

DPS Staff disagrees with the Company's proposal for the following reasons:⁴³⁰

- a. Natural weather variability is nothing new to the Company or the industry, nor are its effects beyond the Company's control.
- b. The Company has long had to deal with mitigating the effects of adverse weather and equipment failures through measures such as tree trimming, pole relocations, new cable technology, weather predictions, and pre-storm planning, all of which are under its control.
- c. Current performance thresholds were set at levels higher than historic average performance values, which takes into account natural weather variability. Historically, Consolidated Edison has met most targets. When it did not meet targets, it fell well below them (Ex. 189).
- d. Setting frequency and duration targets at two standard deviations above the target would provide Consolidated Edison far too much leeway.
- e. The Company's use of only five data points is not sufficient to set reasonable standard deviations (Tr. 3541).
- f. The Company failed to show that two standard deviations would promote existing policy to maintain

⁴²⁹ In its Initial Brief, p. 486, the Company uses these precise figures which add up to \$6 million, but suggests they only add up to \$5 million. Ex. 316, p. 1-5 suggests the correct figures are \$1 million above 1 standard deviation, \$2 million more above 1.5 standard deviations, and \$2 million more above 2.0 standard deviations, for a total of \$5 million.

⁴³⁰ DPS Staff's Initial Brief, pp. 294, 298-99, and 302.

or improve reliability; it is simply a novel way to decrease the probability of a revenue adjustment.

- g. The Company failed to provide evidence that use of two standard deviations accounts only for natural weather variability.

Anticipating DPS Staff's arguments, the Company maintains that DPS Staff has not identified the performance data used to develop the current performance targets and there is no proof that natural weather variability is reflected in the current criteria. It argues that such criteria are more than likely based on average results in the five years ending in 1989, that such results are stale, and that any fixed percentage adjustment above that average to set the existing criteria does not account adequately for natural weather variability.⁴³¹

In reply, DPS Staff contends:⁴³²

- a. The Company exaggerates when it suggests it is exposed to tens of millions of dollars a year for failure to meet outage frequency and duration targets. Its maximum annual exposure for frequency and duration targets for the radial and network systems is currently \$5 million each or a total of \$20 million.
- b. The Company is misleading to argue that adverse weather and natural weather variation cause it to miss targets. For example, the Company's attempt to blame the weather for missing the radial system frequency target in 2006 ignores the interruptions from equipment failures that were within the Company's control.
- c. Contrary to the Company's claim, exclusion of major outages does not affect duration target performance. The 2007 Yorkville/West Bronx network outage to which the Company refers was not a major outage. All large, short duration outages similar to that one would not adversely affect the annual duration target.
- d. The Company's claim that its maximum proposed level of adjustment would be the same as DPS Staff's

⁴³¹ The Company's Initial Brief, pp. 488-489.

⁴³² DPS Staff's Reply Brief, pp. 90-94.

proposed maximum of \$5 million per threshold standard is incorrect. The Company would limit the maximum to \$3 million (Tr. 3547).

- e. The Company's contention, that the outage frequency and duration targets currently in effect for 2008 should also be changed, should not be accepted. The 2008 Rate Order set the targets currently in effect. That order recognized the possibility of changing future targets but did not provide for changes to targets it set.
- f. The Central Hudson electric rate case⁴³³ the Company cites as recognizing the potential impact of a new outage management system on frequency and duration performance targets is not apposite. The standards adopted there were based on a joint proposal.

The Company makes these additional points:⁴³⁴

- a. DPS Staff's claim that the Company has long had to engage in mitigation to deal with the natural weather variability reflected in the historic mean is unavailing, because the historic average already reflects the results of the Company's mitigation efforts.
- b. Although DPS Staff criticizes the Company's proposed standard deviation increments for making revenue adjustments based on the Company's use of only five data points, the current performance targets DPS Staff supports appear to be based on only five data points and the two temporary substitute measures DPS Staff proposes in place of network frequency clearly are based on only five data points.
- c. In the 2008 Rate Order, we left open the possibility of revising the frequency and duration targets set there, based upon further development of facts regarding the efficacy of the STAR system. Here, the facts have been developed sufficiently to warrant changing those targets for 2008, as well as going forward.

⁴³³ Case 00-E-1273, Central Hudson Gas & Electric Corporation, Order Staying Reliability Targets and Rate Adjustments (issued September 29, 2003).

⁴³⁴ The Company's Initial Brief, pp. 475-82 and the Company's Reply Brief, pp. 160-67.

(ii) Discussion

With respect to network SAIFI and CAIDI, it seems clear that one or both should be modified to reflect the Company's use of the STAR system, or that substitutes for both should be adopted, pending additional Company experience with the STAR system. Unfortunately, neither option is a panacea in the short run.

The Company argues in support of modification of the existing SAIFI and CAIDI based on comparisons of results of the STAR and legacy systems for calendar year 2007 and 2005. DPS Staff suggests this is basically the same information presented in the Company's last electric rate case, but that is true only with respect to the study for 2005 (Ex. 317). In the Company's last case, we ordered that the then-existing network criteria remain in place and that the Company should provide further evidence in support of its proposal. Exhibit 316 is responsive to that order and the results for 2007 are very close to those of the study for 2005 examined in the Company's last electric rate case.

No evidence has been produced that identifies what if anything is wrong with Ex. 316. However, DPS Staff suggests that more time is needed (at least one more year), that something else might be going on (STAR may be systematically overestimating the number of customers affected), and that the Company has not provided adequate proof in support of the changes it proposes. DPS Staff does not, however, explain what exactly would comprise a satisfactory level of proof.

The best reason to be gleaned from the evidentiary record for ignoring the results of the Company's two studies is that, while such results suggest the SAIFI network criterion should be increased by 167% to 175%, the Company actually proposes an increase of only 46.66%. Thus, the Company's own position raises doubts about the accuracy of its study results.

The other key option, as noted, is to substitute other measures for network SAIFI and CAIDI. A problem is that the Company criticizes and proposes alternatives to DPS Staff's proposals (i.e., use network outages per customer and the number of open automatics per network in lieu of SAIFI), but DPS Staff does not respond on brief. A related problem is that the Company's counter-alternative proposals are very general, with no specific criteria calculated and explained.

As to network CAIDI, similarly, the Company claims that whether or not manual interventions are key in determining actual outage deviations, its studies nevertheless establish that STAR will predict outage deviations that are at least 25% higher. DPS Staff's position is that the two Company studies to date do not comprise adequate proof.

Based on all of the information presented, our preference would be to set network SAIFI and CAIDI criteria that reflect the new STAR system. In our judgment, however, the Company should have a total of at least three to five years' data from and experience with the STAR system before we would rely on either for these purposes. The issue thus becomes what would be the best substitute for network SAIFI and CAIDI in the interim.

Of the alternatives offered, the best for SAIFI is derived from DPS Staff's proposal to substitute 5700 network interruptions per year and 650 summer open automatics, excluding those from major outages, in lieu of SAIFI, while simultaneously taking into account valid concerns raised by the Company. For network interruptions, the target should account for differences in the number of customers served. Therefore, the target will be 2.50 network interruptions per 1,000 customers served. For summer open automatics, the Company is correct that radial outages should not be included in the metric. Based on the Company's rebuttal testimony, this would result in a target of

510 for summer network open automatics. We reject, however, the Company's arguments that this target should be based on open automatics per network as no specific proposal was put forth on which to establish such targets.

As to the network CAIDI, the two years' of STAR data provided by the Company persuade us that an interim criterion should likewise be substituted. Specifically, network CAIDI should be replaced with network outage duration along the lines of the Company's alternative proposal. For reasons explained below, however, we are adopting a single outage duration target of 4.90.

With these substitutions in place, the Company will be in the same position as it is today in terms of its ability to meet the criteria. In this context, it remains reasonable that \$5 million of revenues be at risk for each of the substitutes for network CAIDI and SAIFI.⁴³⁵

As DPS Staff suggests, it would not be appropriate to revisit in this case the prior decision for calendar 2008. That decision was based on the best information available at the time.

Turning to the related issue of whether SAIFI and CAIDI revenue disallowances should be imposed on a flash-cut or gradual basis, the Company's basic position appears to be that it should be subject to little if any revenue disallowance when bad weather might be the sole or partial root cause of any deterioration in the reliability of its electric delivery service. DPS Staff's basic position, meanwhile, is that the Company can install and operate its system in a manner so that reliability can be maintained and that it is appropriate to

⁴³⁵ The \$5 million revenue adjustment exposure previously applicable to network SAIFI will be divided between network outages (\$4.0 million) and summer open automatics (\$1.0 million).

provide the Company an incentive to ensure the Company maintains reliability in the future to the same extent it has been able to do so in the past. At a fundamental level, we are more persuaded by DPS Staff's position. We also disagree with the Company's approach because it can produce the situation when the Company's reliability slips and its incentive to prevent such an effect also decreases. Moreover, the Company is incorrect when it claims that current reliability targets are based on 20-year old data and that such targets do not already reflect the effects of natural variability. The network targets previously in effect and the radial targets that will continue in effect were first adopted in the 2005-2008 rate plan based on a joint proposal. Such targets were re-evaluated in the Company's last case and readopted. As these targets were based on the Company's actual experience in past years, and as results actually achieved by the Company reflected what it calls natural variability, there is no need to provide for such variability a second time. In sum, we reject the Company's proposal in support of gradual revenue disallowances.⁴³⁶

d. Major Outage Mechanism for Networks

DPS Staff proposes to continue the existing Major Outage mechanism under which the Company would be at risk of forgoing \$10 million of revenue to the extent any outage impacts 10% or more of customers on a network for three hours or more, subject to an annual cap of not more than \$30 million.

The Company objects, noting that it has large and small networks and that it would be vulnerable to a \$10 million revenue disallowance on account of outages impacting as few as 50 customers. Indeed, it says, an outage on 14 of its 61 networks affecting less than 500 customers each would result in a \$10 million revenue adjustment (subject to the \$30 million

⁴³⁶ Appendix VI is a summary of the mechanism we adopt here.

annual cap). In the period 1998 through 2007, the Company continues, it experienced eight outages that would have warranted a revenue adjustment, with four involving less than 100 customers. Forty million dollars of revenue adjustments in those instances would have amounted to \$275,862 per customer interrupted. Accordingly, the Company proposes that the proposed mechanism not apply to networks with fewer than 25,000 customers except in the event of a complete network shutdown. For networks serving 25,000 or more customers, the Company proposes a threshold of 50% or 25,000 customers, whichever is greater.

DPS Staff argues for continuation of the current existing Major Outage mechanism as it applies to networks, which became effective on June 19, 2008, and rejection of the Company's proposal because:⁴³⁷

- a. Outages under this metric fall within the full control of the Company and it should be held accountable for its performance.
- b. The purpose of the metric is not only to capture outages affecting a large number of customers, but also outages in smaller networks that would have an impact on large businesses.
- c. The definition of a major outage was evaluated in the Company's last electric rate case, and a provision was included at that time for the Company to seek exemption on a case-by-case basis for outages that affect more than one building but are still small scale and do not warrant being classified as major outages.⁴³⁸

⁴³⁷ DPS Staff's Initial Brief, pp. 303-305.

⁴³⁸ Case 07-E-0523, supra, Order Adopting Changes to the Definition of Major Outage (issued June 19, 2008). DPS Staff quotes language to the effect that the 10% threshold is justified in any network, because the criterion would have come into play for both the Long Island City and Washington Heights network outages, while the previously effective threshold did not.

The Company is correct to say that it has some networks with a large number of smaller customers and some networks with a small number of large customers. However, the Company never explains why it would be reasonable to provide it an incentive to avoid major outages for smaller customers, but no incentive to avoid major outages for its largest customers. Such an explanation certainly should have been provided given that it was only last year that a new definition of a major outage was adopted based on the percentage rather than the number of customers out of service. For that reason, and as the Company would retain the right to petition for exemptions where only a few buildings are affected, we reject the Company's proposal to modify the major outage component of the Company's RPM.

e. Service Restoration Metric

The Company accepts DPS Staff's proposal that the existing service restoration metric remain in place, without any Company revenues being at risk, including the requirement that following any applicable storm it would file a report detailing its restoration performance.

Nevertheless, the Company continues to have concerns about the need for or appropriateness of a service restoration metric for the following reasons:

- a. The Company is in the process of implementing audit report recommendations in Case 06-M-1078 concerning its performance in outage emergencies and it is premature to establish performance criteria while that work is ongoing.
- b. The focus of the audit report in the referenced case is on adoption of best practices and the report expressly cautions against a narrow focus on restoration times.
- c. The establishment of restoration targets based on the number of customers affected is not reasonable because the key variable is the extent of the damage sustained during an event.

- d. The restoration metric does not account for factors beyond the Company's control.

Anticipating these points, DPS staff argues:

- a. The Company is incorrect in its claim that DPS Staff's proposal uses the number of customers out of service as a target. The restoration mechanism states a restoration time for a specific emergency level set forth in the Company's own emergency plan, and the Company itself sets each emergency level.
- b. Nothing in DPS Staff's proposed restoration mechanism prohibits the Company from establishing other restoration-related requirements on its own. DPS Staff has recommended various measures in previous outage investigations and they have not interfered with Consolidated Edison's ability to resolve system emergencies.
- c. If the Company is unable to get mutual assistance from other utilities during widespread events, it may seek exemption from the target on a case-by-case basis.

On reply, DPS Staff adds:⁴³⁹

- d. There is no merit to the Company's argument that the restoration mechanism conflicts with the implicit purpose of the audit report on its response to outage emergencies. The restoration performance mechanism sets targets, without dictating how to achieve them. The audit report gives recommendations on how the Company should achieve the targets, without affecting how targets are set.
- e. Having a pre-set time certain within which the Company must re-establish service or face a revenue adjustment will give it incentive to use its best efforts to derive a restoration time quickly and assess its resources continually to ensure the time is met.

In its Reply Brief (p. 177), the Company states that it appreciates DPS Staff's discussion on this issue and will be guided by it when preparing reports for future storms during the trial period.

⁴³⁹ DPS Staff's Reply Brief, pp. 94-95.

We decline to adopt any modifications to the existing outage restoration terms of the Company's RPM. Those terms are in effect without any associated potential revenue disallowances as a step in the direction of adopting a refined mechanism at a later date. As stated in the 2008 Rate Order (p. 175), the communication of and achievement of estimated restoration times are essential components of the provision of safe and adequate service. The Company's concerns are more appropriately addressed when we take up the issues of whether and when to place Company revenues at risk for its failure to achieve projected restoration times.

f. Remote Monitoring System Metric

The Company has approximately 24,000 Remote Monitoring System (RMS) devices on its network transformers. The devices transmit information to operating personnel. A third of the transmitters are about 20 years old and characterized as first generation technology. Another 22% are second generation technology and about 10 years old, and the remaining 45% are third generation, latest available technology.⁴⁴⁰

DPS Staff proposes to continue the RMS Metric, under which the Company forgoes \$10 million (up to an annual cap of \$50 million) of revenues if less than 90% of the RMS units in each network are functioning (or reporting). DPS Staff envisions this as an interim metric, pending re-adoption of a 95% threshold for functioning RMS units.

The Company argues as follows:⁴⁴¹

- a. The RMS metric should be discontinued as the Company needs no incentive to maintain RMS availability.

⁴⁴⁰ Note 238 in the Company's Initial Brief, p. 497, seems to say the third generation equipment is 45% and 20% of the total. Its arguments collectively suggest that 45% is the correct figure.

⁴⁴¹ The Company's Initial Brief, pp. 497-500.

- b. The Company's internal goals are more ambitious than 90% and it is currently meeting its internal goals.
- c. The Company was able to bring about significant improvements on its own initiative through early 2007 even though an RMS metric did not exist at the time.
- d. \$10 million per network and a \$50 million cap for RMS revenue disallowances are disproportionate relative to other amounts at risk and caps under the other reliability metrics applicable to Consolidated Edison.
- e. An RMS reporting problem does not mean there are service interruptions. Accordingly, far fewer revenue dollars should be at risk, such as no more than \$100,000 per network with a maximum of \$3 million per year (Tr. 4151-52).
- f. A minimum 90% availability rate is too high given that the Company is involved in a ten-year program to upgrade all RMS transmitters to third generation equipment.

DPS Staff opposes any reduction of the 90% RMS reporting rate for each network because:⁴⁴²

- a. In the Long Island City network outage investigation, Consolidated Edison's own operating procedure requires a 95% RMS effective rate for each network.⁴⁴³
- b. The Company continually operated below the 95% rate, operating its system with an unacceptable level of uncertainty. This shortfall was first identified following the 1999 Washington Heights outage and again following the Long Island City Network outage.
- c. In response to the Company's renewed claim that first and second generation RMS devices were at fault for the failure to maintain the required reporting rate, the RPM standard was dropped from 95% to 90%, below the Company's own specification (Tr. 4148).

⁴⁴² DPS Staff's Initial Brief, pp. 306-308.

⁴⁴³ Case 06-E-0894, Proceeding on Motion of the Commission to Investigate the Electric Power Outage of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, DPS Staff Final Report (issued February 9, 2007).

- d. Funding has been provided for the Company to improve the RMS system reporting rate in each network in recent rate cases.
- e. The RMS remains the only way for the Company to receive continual information on the state of its network system, which is very complex, below ground, and much more difficult to monitor than an overhead system (Tr. 3548).

The remote monitoring system metric of 90% was first adopted in the 2008 Rate Order (pp. 171-172), based in part on evidence that the Company's internal goal was to achieve 95% performance on a regional basis and not less than 90% performance in any network and that this internal goal was repeatedly not achieved. The \$10 million revenue disallowance per occurrence was proposed by DPS Staff with no annual cap, while the Company opposed adoption of any revenue disallowance, either per occurrence or annually. The 90% target was described as a step in the direction of a 95% target in the long term and there was also discussion about a report to be submitted by the Company in May or June 2008.

We do not put much stock in the Company's assertion that it needs no incentive to achieve a target of 90%. Network reporting below the 90% level was experienced prior to both the major Washington Heights and Long Island City outages in the Company's system.

DPS Staff does not reply to the Company's arguments that a \$10 million per event and a \$50 million annual cap for failure to meet this metric is excessive relative to other RPM metrics especially given that service might not be affected. That issue was also not addressed in the direct testimony of DPS Staff's reliability performance mechanism panel (Tr. 3531-3551).

The reason for this, however, is that the Company's contentions about the RMS dollars at stake are presented in its update/rebuttal testimony (Tr. 4151). Given that the remote monitoring component of the RPM is already in effect and the

Company presented this information at a time when DPS Staff would have no opportunity to reply with testimony, we conclude the record on this issue is not adequate to justify any change at this time.

g. Program Standards

Performance criteria for repairs to damaged poles, the removal of temporary shunts, repair of street light services, and the replacement of over-duty circuit breakers were adopted in 2005. Annual revenues of up to \$3 million each are at risk when the Company fails to meet the applicable criteria. For example, the Company is subject to a revenue adjustment of \$100,000 for each of 60 over-duty circuit breakers it does not replace in a rate year.⁴⁴⁴

The Company argues that these performance criteria should be eliminated for the following reasons:⁴⁴⁵

- a. The Company has met or exceeded all these performance targets since they were established in 2005.
- b. The Company has met or exceeded another performance metric adopted in 2005 (related to the time for energizing new street lights) even though there were no revenues at risk for that metric. That metric has since been discontinued.

Alternatively, the Company proposes that the performance metrics remain in place with no revenues at risk, so that it can be afforded an opportunity to prove that it can provide good service without being at risk for a revenue loss.

Anticipating these arguments, DPS staff supports continuation of the program standards because these are areas in which the Company failed to complete work on its own initiative in the past (Tr. 3550). DPS Staff opposes the Company's rebuttal claim that if it exceeds expected performance levels

⁴⁴⁴ A \$3 million annual cap also applies. Other examples are shown in the Attachment.

⁴⁴⁵ The Company's Initial Brief, pp. 500-501.

over time, there is no need to continue a performance metric because:⁴⁴⁶

- a. The components of the mechanism should continue so that Consolidated Edison will be held accountable for items not properly handled on its own initiative in the past.
- b. If the Company continues to meet the targets, it will not be subject to any revenue adjustments.

The NYC Government Customers also oppose the Company's proposal to eliminate the four metrics. According to these parties:⁴⁴⁷

- a. The four metrics were first adopted in March 2005 in part to encourage the Company to correct serious deficiencies in streetlight service it provides. Problems included numerous streetlights without electric service and a proliferation of streetlights served by shunts or cables installed to provide service pending a permanent repair.
- b. The four metrics were re-adopted in the Company's last electric rate case at which time it was determined that the RPM was an essential component of just and reasonable rates for the Company. The Company has not demonstrated any change in circumstances that warrants a different outcome.
- c. The fact that the Company has met all four metrics since they were first adopted in 2005 shows that the RPM worked and that safety and reliability have improved. However, this improvement is not a reasonable justification for eliminating the metrics from the RPM.

We decline to drop the program standards for pole repairs, stunt removal, no-current street lights and traffic signals, and over-duty circuit breakers. The shunt removal and over-duty breaker standards are critical. We are also reluctant to remove the pressure these criteria place on the Company to address pole repairs and no-current street lights and traffic signals.

⁴⁴⁶ DPS Staff's Initial Brief, pp. 311-312.

⁴⁴⁷ NYC Government Customers' Initial Brief, pp. 73-76.

h. Effective Period of the Reliability Performance Mechanism

DPS Staff proposes that Consolidated Edison be required to file proposed revisions to the RPM based on the mechanism in place at the time of its rate proceedings.⁴⁴⁸ It also urges that the RPM for this proceeding should become effective January 1, 2009, and remain in effect until reset, because the majority of items subject to the RPM are reported and evaluated on a calendar year basis (Tr. 3542).

The Company does not discuss the first topic in its initial brief. However, it disagrees with DPS Staff's proposal that the RPM remain in effect until modified. It argues the RPM should be effective during the period for which base rates are set in these proceedings. Citing the 2008 Rate Order (p. 163), the Company asserts that the RPM should be reset each time the rate of return is considered, to ensure revenues at risk are reasonable in the context of the return allowed at that time.⁴⁴⁹

The Company's Reply Brief also objects to the statement in DPS Staff's Initial Brief that "the Company should be required to file proposed revisions to the RPM based on the existing mechanism in rate proceedings."⁴⁵⁰ The Company complains that this proposal was not presented in DPS Staff testimony and is unsupported in the record; it amounts to micro-management; it is inappropriate because the RPM mechanisms themselves are inappropriate; it will inhibit innovation regarding incentive regulation and undermine even-handed and more effective approaches to maintaining good service; it unfairly shifts the burden of proof to the Company for a

⁴⁴⁸ DPS Staff's Initial Brief, p. 293.

⁴⁴⁹ The Company's Initial Brief, p. 501-502. We understand the Company to be referring to each time the return on equity is considered for its electric operations.

⁴⁵⁰ The Company's Reply Brief, p. 178, citing DPS Staff's Initial Brief, p. 293.

mechanism that it does not support and that is not an element required for a rate filing under Commission regulations; and it unfairly targets the Company when no other electric utility is subject to such a requirement.

We reject the Company argument that DPS Staff and other parties have the burden of proof with respect to a Reliability Performance Mechanism, simply because the Company disagrees in principle with the use of such mechanisms. This Commission has long held that incentive mechanisms are appropriate for ensuring the quality provision of monopoly utility services. The 2008 Rate Order stated that various elements of the Company's RPM are essential to the provision of safe and adequate service. If the Company wants permission to increase its rates and charges, accordingly, it must be prepared to meet its burden of proving that its overall rate plan would be reasonable in light of prior precedent.⁴⁵¹

There is no dispute about the proposed effective date of January 1, 2009 for RPM terms adopted in this case. As to how long such terms should remain in effect, the Company was previously understood to recommend that such terms should expire automatically at the end of the Rate Year. Now that it is clear that the Company agrees the RPM terms should apply until rates are set again in another electric rate case, we do not believe there is any meaningful difference between the Company's and DPS Staff's positions.

Turning to DPS Staff's proposal about the appropriate timing of the Company's direct presentation, the record in this case is deficient in part because the Company's presentation on one or more RPM criteria is part of its update/rebuttal case filed in late September 2009. DPS Staff's proposal would avoid a recurrence of this problem and that proposal is adopted.

⁴⁵¹ PSL §66(12)(i).

2. Customer Service Performance Mechanism

DPS Staff proposes that the Company's electric Customer Service Performance Incentive (CSPI) be continued. The existing CSPI is summarized on the record as follows:⁴⁵²

A maximum revenue adjustment in favor of customers of up to \$40 million annually (equivalent to approximately 33 basis points of electric common equity) is applicable if the Company does not meet customer service threshold targets. The Company files a report annually on its performance under the incentive mechanism. The customer service performance metrics...[concern] the following areas: PSC complaint rate; satisfaction of electric emergency callers and other non-emergency callers to the Company's telephone centers and visitors to the Company's service centers; time to complete new and initial service jobs, initial phase; time to complete new and initial service jobs, final phase; meter reading, percent read on cycle; telephone calls, percent answered; billing accuracy (percentage of bills not adjusted due to Company error); routine investigations (percentage completed within 30 days); and the Outage Notification Incentive Mechanism (ONIM), a measurement of the Company's performance in customer notification of service outages. For measurement purposes, under the terms of the existing rate plan, performance resulting from abnormal operating conditions, such as strikes, natural disasters, major storms and other unusual events, are not considered. In such cases, Con Edison will omit data for the affected geographic area from the calculation.

DPS Staff points out that the CSPI was updated in the 2008 Rate Order, and states that it opposes the Company's rebuttal request that the CSPI be discontinued, because:⁴⁵³

- a. The Company's Customer Operations Panel maintains the CSPI should be discontinued for reasons stated in the rebuttal/update testimony of the Company's Infrastructure Investment Panel (Tr. 1436).

⁴⁵² Tr. 4713-14.

⁴⁵³ DPS Staff's Initial Brief, pp. 312-13.

- b. The Infrastructure Investment Panel's discussion was limited to the RPM and did not address the CSPI.
- c. Thus, the Company has presented no justification for discontinuing the CSPI.

The Company opposes DPS Staff's proposal for the following reasons:⁴⁵⁴

- a. The Company provides excellent service because customer focus is the essence of its mission.
- b. The Company expects its employees to exhibit customer focus and the Company understands it is responsible for ensuring its employees have the resources they need to do this work effectively.
- c. The Company disagrees with DPS Staff's assertion that good customer service will occur only if a portion of the Company's revenues are at risk. The Company has operated with a customer service performance mechanism in place since 1992 and during that time, there was only one revenue disallowance associated with missing a communication metric during the LI City outage. The Company's long-standing performance is the result of dedication to customer service, not the result of possible negative financial consequences.

Alternatively, the Company argues the mechanism should be retained but with no revenue adjustment provision, to afford it an opportunity to test DPS Staff's assertion that possible financial consequences are the driving force behind the Company's long history of high quality customer service.

The Company's direct case was silent on the CSPI mechanism and its reasons for opposing such a mechanism are offered in update/rebuttal testimony to which DPS Staff had no reasonable opportunity to respond. This problem will be avoided in the future because we are requiring the Company to present its position on the existing customer service performance mechanism in its future rate case filings.

Turning to the merits, the CSPI measures whether the Company is providing good customer service using a broad number

⁴⁵⁴ The Company's Initial Brief, pp. 502-503.

of indices. It is consistent with the long-standing policy of using performance metrics as an incentive for good utility performance. In this light, the fact that the Company experienced only one revenue adjustment under this mechanism over more than 15 years is not a reasonable basis for discontinuing this general service quality mechanism. DPS Staff's position is adopted.

B. Three-Year Rate Plan

The judges recommended against a three-year rate plan, observing that such a proposal was initially supported by the Company, that the Company's support for a multi-year plan gradually became more nominal than real, and that the Company had not committed to refrain from filing for another rate increase to be effective during the three-year rate plan.⁴⁵⁵

The Company excepts, pointing out that it never updated its second- and third-year revenue requests as they would build on amounts allowed for the Rate Year using escalation factors.⁴⁵⁶ It argues further that it is entirely proper that it reserve its right to file for new rates if it is dissatisfied with the rate plan terms adopted for any or all of the rate years. In light of our long-standing support for multi-year rate plans, the Company says that it is confounded by the fact that consideration of a multi-year rate plan in these cases did not go beyond reasons why such a plan should not be adopted and did not include an exchange of ideas that could lead to a multi-year rate plan beneficial to all.

Westchester, the only party to reply, opposes the Company's exception on the grounds that a three-year rate plan would be ill-advised for both ratepayers and the Company in light of the current economic turmoil. This turmoil, it says,

⁴⁵⁵ R.D., pp. 314-316.

⁴⁵⁶ The Company's BoE, pp. 60-61.

makes it more difficult to estimate many factors affecting revenue requirement.⁴⁵⁷

We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing--the third in three years--ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.

In these particular cases, however, we do not see a sufficient record basis to compare the results of one three-year litigated rate case and three one-year litigated rate cases, much less to conclude that one approach would be superior to the other. We therefore agree with the judges' recommendation against a three-year rate plan here and deny the Company's exception. Nonetheless, we encourage the Company, DPS Staff, and other parties to explore the possibility of a multi-year rate plan seriously and fully as part of Consolidated Edison's next electric rate case, whether on a litigated or negotiated basis.

We wish to impress upon the Company the importance that its next rate request be complete in all respects upon filing, including all underlying workpapers, studies and

⁴⁵⁷ Westchester's BOE, pp. 11-12.

analyses, calculations, and assumptions. We also underscore the Company's obligations under Part 61 of our rules of procedure,⁴⁵⁸ to which we believe it gave too little attention in these cases. We expect DPS Staff and the other parties to identify formally or informally any elements missing from the Company's presentation, and seek appropriate relief, as promptly as possible. If the Company includes a multi-year rate proposal as part of its initial filing--although the level of detail required in support of the filing is to some extent dependent on the scope and complexity of the proposal itself--the quality and specificity of the supporting information accompanying that proposal must be sufficient to provide the parties a reasonable opportunity to review and analyze it in a timely manner. If the judge finds material deficiencies in the Company's filings, she or he has the power to fashion appropriate remedies. For example, any decision to allow the Company to supplement its filing may be made subject to appropriate conditions to protect the interests of other parties and ratepayers. Finally, consistent with our discussion in section XII(D) below, any multi-year rate plan proposal the Company submits must include a detailed explanation of all steps it will take to achieve appropriate austerity savings during the period the rate plan is proposed to be in effect.

C. Deferral Accounting/Reconciliations

1. New Laws and New Taxes

The Company proposed numerous deferral and reconciliation terms, including one concerning changes resulting from new laws and new taxes. The judges noted this Company proposal and made clear that they were not recommending it. However, they gave no reason.⁴⁵⁹

⁴⁵⁸ 16 NYCRR Part 61.

⁴⁵⁹ R.D., pp. 316-319.

The Company excepts, complaining about the judges' failure to give any reason.⁴⁶⁰ DPS Staff had opposed this Company proposal, arguing a reconciliation for new laws and tax changes is inappropriate in the context of a one-year rate case and that the Company would be free to petition for relief (a deferral petition) if any such changes had a material impact on the Company's earnings. The Company disagrees with both of these arguments. As the recommended decision properly acknowledges in connection with property taxes, the Company continues, there is no substantial difference between providing for a true-up in a one-year rate case and in the first rate year of a multi-year rate plan. It asserts, moreover, that the proposed reconciliation would be beneficial to the Company and ratepayers. The Company maintains as well that allowing it to file a deferral petition is an inadequate remedy in the current environment, where there is an abnormally high level of legislative activity that could materially affect its costs. The Company concludes, asserting that the judges' reasons for supporting full reconciliation of property taxes applies as well to the revenue requirement impacts of other changes in law and taxes.

No party replies.

The basic issue presented concerns what level of the Company's delivery service revenue requirement should be subject to full reconciliation. We authorize here a continuation of all full reconciliations currently in effect. In light of the economic downturn, we are also authorizing full reconciliation for property taxes and debt costs in the context of a one-year litigated rate case. In our judgment, this provides the Company with a reasonable level of downside earnings protection and simultaneously minimizes the chances of ratepayers paying too

⁴⁶⁰ The Company's BoE, pp. 62-63.

much. The Company also undermines its exception to the extent it contends new laws or other tax changes could materially affect its income. In appropriate circumstances, a material impact on income can be a reasonable basis for authorizing deferral and subsequent amortization in rates.

2. Offsets of Deferred Debits and Credits

The Company proposed that it be allowed to offset deferred debits against deferred credits in order to simplify its reporting and make its financial reports more meaningful to investors. It argued as well that such a set-off would minimize net deferrals to be passed back to or recovered from customers. The judges recommended the Company's approach, citing the absence of any arguments about why deferred debits and credits should not be automatically offset against one another.⁴⁶¹

DPS Staff excepts, noting that its reply trial brief explained that the Company's proposal would make it more difficult for it to monitor the Company's accounting of deferrals for regulatory purposes.⁴⁶²

The Company replies, noting for the record that it does not agree that netting deferred debits and credits would make it more difficult for DPS Staff to monitor the Company's accounting.⁴⁶³

DPS Staff's exception is granted for the reasons it states and as the Company does not explain the reasons behind its responsive comment.

D. Mandatory Hourly Pricing (MHP)

In the 2008 Rate Order we approved expansion of Mandatory Hourly Pricing (MHP) to customers with demands over 500 kw in any month, which the Company is currently implementing

⁴⁶¹ R.D., pp. 317-319.

⁴⁶² DPS Staff's BoE, p. 67.

⁴⁶³ The Company's BoE, p. 79, n. 76.

in two phases. DPS Staff proposes that the Company be required to: (1) evaluate the current expansion to customers with demand of over 500 kW, including load responsiveness, customer satisfaction, and lessons learned; and (2) based upon that evaluation, develop a plan and schedule to extend MHP to customers with demand of 500 kW or less.⁴⁶⁴ The Company agrees there should be such an evaluation before further expansion of MHP to lower demand customers, but contends that the nature and cost of the evaluation should be determined in a future proceeding, after completion of the second phase of the current expansion, which will not take place until after the Rate Year.⁴⁶⁵ DPS Staff did not interpose any objection to the Company's point.

We expect DPS Staff to continue to monitor the Company's implementation of its expansion of MHP to customers with demand greater than 500 kW. We will require the Company to file, within six months after completion of implementation of the second phase of that expansion, a report evaluating the expansion program that addresses at least those factors DPS Staff set forth, together with any others the Company believes significant. The evaluation should also include an assessment of expanding MHP to customers with demand of 500 kW or less. Unless the evaluation clearly shows major obstacles to effective expansion, the report shall also include a plan and schedule for implementing MHP expansion and an estimate of the costs of expansion.

1. MHP Billing

CPA proposes that Consolidated Edison be required to provide shadow billing to all new MHP customers for one year before implementing MHP, because:⁴⁶⁶

⁴⁶⁴ DPS Staff's Initial Brief, pp. 327-28.

⁴⁶⁵ The Company's Initial Brief, p. 509.

⁴⁶⁶ CPA's Initial Brief, p. 4.

- a. An extensive period of familiarization and opportunity to reduce usage is necessary to implement MHP without excessive customer confusion (Tr. 3499).
- b. A year of shadow billing of the MHP price is reasonable and similar to the approach used to implement steam demand rates.

The Company, supported by RESA and SCMC, objects to CPA's proposal. The Company states:⁴⁶⁷

- a. Although there were some billing problems during earlier implementation of MHP for greater demand customers, CPA agreed all prior MHP billing issues had been resolved (Tr. 3506).
- b. The Company has successfully billed its current MHP population for two years.
- c. The Commission has already rejected shadow billing as unnecessary.
- d. The Company is planning extensive outreach and education efforts to assist customers with MHP-related issues.
- e. Shadow billing, as proposed, would necessarily delay implementation of MHP.

RESA supports the Company's current schedule for the expansion of MHP, but suggests the Commission should tweak the Company's MHP program by requiring Consolidated Edison, upon request by an ESCO, to provide access to a customer's full 24 months of historic hourly interval data, instead of the 12 months currently provided. RESA suggests:⁴⁶⁸

- a. This data can be provided without any administrative obstacles.
- b. The requested additional information is already provided by National Grid, RG&E, NYSEG, and Central Hudson.
- c. Provision of such data will afford ESCOs an opportunity to develop more accurate, efficient, and less costly pricing models and better products.

⁴⁶⁷ The Company's Initial Brief, pp. 509-19.

⁴⁶⁸ RESA's Initial Brief, p. 8. SCMC generally supports the same proposal. See SCMC's Initial Brief, p. 12.

Contrary to the Company's claim, in the 2008 Rate Order we did not consider, much less reject, shadow billing prior to expansion of MHP for customers with demand >500 kW and ≤1.5 MW. We did, however, require the Company to include sufficient time in the implementation schedule to provide six months of hourly interval data for customers with demand >1.0 MW and ≤1.5 MW and one year of interval data for customers with demand >500 kW and ≤1.0 MW.⁴⁶⁹ We found there that:⁴⁷⁰

...[A]doption of this schedule strikes a reasonable balance between expediency, on the one hand, and, on the other hand, the desire to ensure that eligible MHP customers have sufficient time and data to see how their load is affected by season, production patterns, weather and the like, and to effectively make adjustments to their load patterns in an anticipation of the new Hourly Pricing Tariff.

CPA does not respond to the Company's criticism of its shadow billing proposal. Nor does it explain why the extent of the information we have already required as part of the Company's MHP expansion program, together with the Company's associated outreach and education efforts and customer assistance, are insufficient and warrant further delaying MHP expansion. We will not adopt CPA's shadow billing proposal.

The Company offers no objection to RESA's proposal that the Company be required to provide an ESCO, upon request, with a customer's full 24 months of historic hourly interval data. We find RESA's proposal reasonable and we adopt it.

E. Retail Access Issues

1. Outreach and Education

DPS Staff agreed with the Company's proposal to discontinue its "Power Your Way" outreach and education program on retail access, reducing revenue requirement by approximately

⁴⁶⁹ 2008 Rate Order, supra, p. 67.

⁴⁷⁰ Id.

\$1.662 million plus revenue taxes. The Retail Energy Supply Association and the Small Customer Marketer Coalition opposed the proposal, arguing that some level of outreach and education on retail access should continue even if past promotion of retail access will not be continued.

The judges recommended that \$730,000 of the \$1.662 million be restored (exclusive of revenue taxes) to cover the costs of a Green Power Campaign (\$650,000), a Green Power bill insert (\$72,000), and the Company's maintenance of an up-to-date list of retail electric energy suppliers (\$8,000).⁴⁷¹

DPS Staff excepts, arguing (as it did in its reply trial brief), that an October 27, 2008 order makes clear that objective outreach and education about retail access should continue to be disseminated within the ambit of usual utility outreach and education budgets for customer education.⁴⁷² DPS Staff contends as well that there is no record support for the two larger amounts the judges recommended and that it can be expected that the Company would continue to maintain up-to-date lists of retail electric energy suppliers as part of its general outreach and education.

Responding in opposition to DPS Staff's exception, the Retail Energy Supply Association (RESA) argues that there is nothing in the October 2008 order cited by DPS Staff that precludes a utility from allocating a specific level of expenditures within its overall outreach and education budget to address retail access activities.⁴⁷³ It adds that the record is replete with information about specific retail access programs the Company should fund in the Rate Year. This includes

⁴⁷¹ R.D., pp. 320-321.

⁴⁷² DPS Staff's BoE, pp. 67-69, citing Case 07-M-0548, Proceeding on Motion of the Commission - Retail Access, Order Determining Future of Retail Access Programs (issued October 27, 2008), p. 13.

⁴⁷³ RESA's BOE, pp. 3-4.

expenditures for bill redesign, business and residential events, Power Your Way educational reminders, and the distribution of ESCO lists.

RESA also excepts, arguing as follows:⁴⁷⁴

- a. The budget for outreach and education or retail access should be on the order of \$300,000 to \$400,000 so that the Company can comply with the October 2008 order cited by DPS Staff and in light of the fact that the Company initiates approximately 300,000 new services per year. The \$8,000 recommended by the judges for a list of energy suppliers is woefully inadequate.
- b. The Company acknowledged during cross-examination that much of the \$1.622 million Test Year amount was related to educational rather than promotional activities.
- c. Providing educational materials on retail access and energy efficiency is more important in more difficult economic times, so that customers can enjoy bill savings.

There is a record basis for the amounts proposed by the judges⁴⁷⁵ and RESA's exception is undermined to the extent its proposed \$300,000 to \$400,000 annual retail access outreach and education budget is proposed for the first time in its brief on exceptions. RESA also overstates its argument when it suggests the Company is adding 300,000 customers per year. The record shows that figure includes existing customers taking service at new locations.⁴⁷⁶

More fundamentally, however, DPS Staff is correct that we now anticipate that New York utilities' retail access outreach and education should continue within the ambit of their general outreach and education budgets.⁴⁷⁷ In this case, that

⁴⁷⁴ RESA's BoE, pp. 4-7.

⁴⁷⁵ Ex. 382, Table 2.

⁴⁷⁶ Tr. 4723.

⁴⁷⁷ The judges acknowledge that they missed this argument in DPS Staff's trial briefs.

budget is \$3.631 million annually.⁴⁷⁸ DPS Staff's exception is granted and RESA's exception is denied.

2. Display of Full Service Supply Costs on Retail Access Bills

CPA proposes that the Company be required to display its full energy supply cost under its electric tariff on all bills, including retail access bills, because:⁴⁷⁹

- a. Consolidated Edison bills are particularly complex and difficult for consumers to interpret. Displaying full service supply costs would facilitate understanding and transparency essential to evaluate alternative supply options and make competitive markets work efficiently (Tr. 3595).
- b. Although the Company argues price volatility in monthly costs can confuse customers, that is no reason to withhold information from them. In any event, consumers need monthly costs to compute annual costs for comparative purposes.
- c. Any burden on the Company of providing this information is outweighed by the burden on consumers of either trying to develop this cost on their own or accepting unfavorable supply offers based on incorrect evaluation of the Company's complex rates.
- d. Full supply costs are displayed on bills in other jurisdictions, even New Jersey.

The Company opposes CPA's proposal, maintaining:⁴⁸⁰

- a. Showing monthly costs of supply for full service would not provide enough or relevant information and could induce customers to switch supply based on insufficient, short-term comparisons. Offerings of alternative suppliers are usually based on long-term pricing models and best compared over a longer period, such as 12 months, which also would take seasonality into account.
- b. Customer inquiries about various supply alternatives and requests to switch suppliers could increase call

⁴⁷⁸ Ex. 382, Table 2.

⁴⁷⁹ CPA's Initial Brief, pp. 4-5.

⁴⁸⁰ The Company's Initial Brief, pp. 511-12; the Company's Reply Brief, pp. 181-82.

center volume, necessitating an increase in call center staffing and capital and O&M costs, which would have to be determined and recovered.

- c. There are complex system requirements for providing full service billing amounts on all customers' bills, such as those for customers subject to MHP billing, and the requirements would have to be determined and associated costs would have to be computed and recovered from customers.
- d. The value of this information has not been established well enough to overcome the potential time and expense necessary to provide it to satisfy one consulting firm's interest.

RESA and SCMC both support the Company's contentions and add:⁴⁸¹

- a. To assist consumers in comparing costs and benefits of supply from the Company and alternative suppliers, it would be better for the Commission to require the Company to continue publishing monthly market supply charge (MSC) estimates.
- b. CPA's proposal ignores that there are non-commodity savings associated with retail access, such as the avoidance of merchant function charges, possible reductions in tax obligations, and other benefits.
- c. CPA's proposal is anticompetitive. The utility and all ESCOs compete to provide commodity. Just as it would be inappropriate to require the Company to show an ESCO's commodity costs on a retail access bill, it is unwarranted to include the Company's supply costs on bills it renders to its full service customers.
- d. The large customers CPA represents are sophisticated enough to examine all the options without any need for CPA's proposal.

CPA disputes RESA's and SCMC's claim that CPA's proposal would misstate full service costs by ignoring savings related to the merchant function charge, tax obligations, or other benefits, since its proposal is to display on the bill all

⁴⁸¹ RESA's Initial Brief, pp. 14-16; SCMC's Initial Brief, pp. 9-10.

the charges that apply to full service customers.⁴⁸² In addition, it argues that RESA and SCMC err in maintaining that disclosure of the Company's rates would be anticompetitive, because the Company's rates are determined by tariff, not by market forces or marketing strategy, and are publicly available by law.⁴⁸³

In its Reply Brief, RESA responds to CPA's arguments, stating:⁴⁸⁴

- a. CPA provides no persuasive factual support: that customers require historic Company full service supply costs on all retail access bills; or that would assuage concerns that the data could be confusing or inaccurate and fail to provide a complete picture of all costs and benefits of retail access versus full service supply.
- b. Although the bill display CPA seeks is included in New Jersey's retail access program, retail access there has not advanced to the significant level achieved in New York, especially for small customers.

CPA's proposal has theoretical appeal. More information for consumers on costs of alternative supply can improve transparency and efficiency in competitive markets. RESA's and SCMC's argument that showing the Company's supply costs on bills would be anti-competitive has it precisely backwards.⁴⁸⁵ Consumers can obtain commodity costs of electricity provided by alternative suppliers from those alternative suppliers, without those costs being shown on the Company's bills. They must obtain information on the cost of

⁴⁸² CPA's Reply Brief, p. 6.

⁴⁸³ Id.

⁴⁸⁴ RESA's Reply Brief, pp. 2-3.

⁴⁸⁵ CPA's suggestion that showing the Company's supply cost on the bill would not be anti-competitive because the Company's rates are set by tariff, not market forces, is hardly more logical. The Company's charge for commodity it supplies is a flow-through based on the cost of its commodity purchases in competitive markets.

electricity that the Company supplies from the Company, whether on the bill or some other way. The easier it is for customers to get information on the cost of taking supply provided by the Company itself, the easier it will be to compare that cost with the cost of electricity from an alternative supplier and the more competition will be enhanced. Suggestions from the Company, RESA, and SCMC that the proposal would benefit only CPA as a consulting firm, or large customers sophisticated enough to examine all available options on their own, hit wide of the mark, since the proposal would apply to all customers' bills.

CPA's contention that potential customer confusion from more information is no reason to withhold information also has surface appeal, as does its point that customers would be able to determine annual supply costs from summing monthly data. RESA's and SCMC's argument that there are non-commodity savings associated with retail access, such as the merchant function charge, is undercut because CPA, as it notes, proposes that each applicable charge be shown on the bill. The difficulty arises in anticipating customer ability to put the information on the bill to proper use. CPA argues that the Company's bills are already particularly complex and difficult for customers to interpret. Adding more cost information, and perhaps advice on how to apply it (such as an admonition to look at an annual commodity charge total, rather than a one-month snapshot, for comparison purposes) can only increase bill complexity. The added information might be particularly confusing for a retail access customer, which would see a cost that it did not bear and that did not figure into calculation of its bill.

Given the risk of exacerbating the complexity of customer bills and difficulty of interpreting them -- together with the lack of information on what modifications the Company would have to make to provide the proposed information on all customer bills, regardless of service class or rate category, or

associated costs -- we cannot at this time determine whether the potential benefits of adopting CPA's proposal are likely to outweigh the potential detriments. Therefore, we will not adopt CPA's proposal.

3. Unaccounted for Energy

RESA, supported by SCMC, explains that electric commodity service costs include the value of losses incurred in transmitting and distributing energy from the point of generation to the point of delivery. These losses are calculated as the difference between total load (net of station power load) and metered load (net of station power load) in a particular zone. ESCOs and their customers must provide compensation for those losses as part of the overall cost of the commodity, based on an "unaccounted for energy" (UFE) percentage determined by dividing that difference by net metered load.⁴⁸⁶ The Company currently calculates the UFE as a single aggregated, average monthly figure by zone.

RESA and SCMC propose that the Company be required to provide ESCOs with hourly UFE data, rather than a single monthly figure, for these reasons:⁴⁸⁷

- a. Based on a 2002 Company study, its total losses comprised more than 7% of total generation and purchases. Retail access customers have to purchase enough energy to replace these losses.
- b. The Company acknowledges that UFE increases when demand increases, that UFE varies by hour, and that it is possible UFE increases when energy costs increase.⁴⁸⁸
- c. The Commission should grant ESCOs access to hourly UFE data by zone to ensure customers receive timely

⁴⁸⁶ Ex. 383, Response to Question 19A.

⁴⁸⁷ RESA's Initial Brief, pp. 16-17; SCMS's Initial Brief, pp. 10-12.

⁴⁸⁸ Ex. 383, Response to Question 19E and Tr. 4358 and 4360.

and accurate information concerning the cost of their usage.

- d. While the Company's current retail access plan does not require the Company to provide hourly UFEs by zone, neither does it prohibit dissemination of that information.
- e. The proposal is practical because the Company acknowledges that it could provide such data on an aggregated basis without having to install any additional meters or undertake costly infrastructure improvements.⁴⁸⁹

The Company responds with two points.⁴⁹⁰ First, it cites a NYISO Market Tariff provision relying on the transmission owner's retail access plan, together with a section of the Company's Retail Access Implementation Plan and Operating Procedure, which sets forth how the Company will provide hourly usage data for ESCOs to the NYISO. Second, the Company appears to argue that, although it theoretically could attribute UFE to particular customers, it is not responsible for providing UFEs to ESCOs on a customer-specific basis.

The Company does not explain the relevance of its citation to its retail access plan. If its point is that its own document does not require it to provide the hourly UFE information RESA and SCMC seek to ESCOs, but only to the NYISO, that response is inadequate. The simple answer is that we can require it to change its retail access plan to provide the information sought. In response to the Company's second point, RESA stresses that it does not propose that the Company provide ESCOs with information on line losses attributed to particular customers. It seeks only provision of hourly loss data on an aggregated basis by zone, rather than just one monthly factor on an aggregated basis by zone, which currently prevails.⁴⁹¹ The

⁴⁸⁹ Tr. 4363.

⁴⁹⁰ The Company's Initial Brief, pp. 512-13.

⁴⁹¹ RESA's Reply Brief, pp. 3-4.

Company has not offered any reason why it could or should not reasonably be required to supply such information. We thus will require the Company to provide that information to ESCOs and to file within 30 days of the date of this order a revised retail access plan incorporating changes reflecting that requirement.

Joint Supporters states its agreement with RESA's and SCMC's proposal that the Company provide hourly loss data by zone to ESCOs, but recommends that such data be made available to all load serving entities, including providers of energy efficiency, demand response, and distributed generation (DG) services, to promote more effective decisions on purchasing and consumption of their services.⁴⁹² Inasmuch as this expanded proposal was first made in Joint Supporters' reply brief and other parties never had any opportunity to consider it in hearings or in brief, the expanded proposal's full implications -- whether positive or negative -- are unknown and untested on the record here. We reject the proposal as untimely.

4. Timely Meter Reading Information

NYECC proposes that Consolidated Edison be required to reconcile differences between what the Company and NYECC member Constellation New Energy (Constellation), respectively, contend is the average lag time between the date when the Company collects meter data and the date when it reports the data to Constellation. If Consolidated Edison is not in compliance with reporting time requirements, NYECC asks the Commission to compel the Company to lower the lag time to a period similar to that achieved by its affiliate, O&R. NYECC argues that:⁴⁹³

- a. Constellation receives billing data from O&R within three days of collection, on average, compared to

⁴⁹² Joint Supporters' Reply Brief, pp. 3-4.

⁴⁹³ NYECC's Initial Brief, pp. 30-31.

about ten days on average from the Company (Tr. 4596-97).

- b. The Company should be able to achieve the same performance level as its affiliate.
- c. Delays in receipt of billing data adversely affect Constellation and other NYECC members because they employ a range of sophisticated market monitoring and hedging strategies that depend on timely information to respond to market conditions that can change daily, or even hourly (Tr. 4597).
- d. Delay in receiving billing data from the Company can undermine the effectiveness of these risk management strategies.

The Company argues as follows:⁴⁹⁴

- a. The Commission's established deadline for the transfer of utility meter reading information to an ESCO is set forth in the Electronic Data Interchange Rules, i.e., one day from validation of the reading of the estimate.
- b. The Company has consistently met this requirement, except in one recent instance in which a system problem delayed a data transmittal by one day.

In its reply brief, NYECC notes that inconsistencies between information from Constellation and the Company on lag time in communicating usage data to Constellation might be due to data validation issues the Company cited in brief.⁴⁹⁵ NYECC suggests that the Commission reconcile reporting times between the Company and Constellation and, if the Company is not in compliance with reporting time requirements, require it to come into compliance.⁴⁹⁶

There seems to be no substantial reason for us to become involved in reconciling this reporting time issue at this point. Constellation should take the initiative to meet with the Company and seek to resolve the differences it perceives in

⁴⁹⁴ The Company's Initial Brief, pp. 510-11.

⁴⁹⁵ Ibid., p. 511, n. 243.

⁴⁹⁶ Ibid., pp. 20-21.

timing of meter reading information transmission, including whether they might be due to data validation problems. If Constellation and the Company fail to resolve the issue, Constellation can seek further relief. Any required action at that time could and should be taken outside the context of a major rate case.

F. Estimated Billing/Use of Automated Meter Reading (AMR)

1. Use of Load Shapes and Rectifying Data Aberrations

NYECC proposes that the Commission (a) establish a collaborative effort to consider rectifying gaps in Consolidated Edison's collection of load profile data on interval meters for MHP and (b) require the Company to publish a prioritization protocol for rectifying the data gap problem, on the grounds that:⁴⁹⁷

- a. When the failure in collecting load profile data for an MHP customer exceeds 4%, Consolidated Edison routinely uses class average load curves, rather than extrapolate from the customer's actual data (Tr. 1443, 4595).
- b. Despite MHP customers' efforts to modify actual consumption in response to hourly price signals, they are charged according to only class average performance, which undercuts the purpose for mandating hourly pricing for larger customers (Tr. 4596).
- c. Wholesale electricity providers cannot justify commodity cost discounts based on actual load profiles as long as Consolidated Edison reports consumption based on class average profiles rather than actual usage levels (Tr. 4596).
- d. The mandate to extend hourly pricing to even more customers increases the urgency of eliminating use of average load slopes instead of actual interval consumption data.
- e. The Company is willing to participate in a collaborative on this issue (Tr. 1468).

⁴⁹⁷ NYECC's Initial Brief, pp. 28-30.

Similarly, RESA contends that the Company unreasonably rejects the use of all interval data recorder information for a billing period even when not all of the information is suspect. It argues that the Company should be required to modify its current billing system so that interval meter data is retained for purposes of billing customers and reporting hourly load obligations to the NYISO. According to RESA, defaulting to class load shape data for billing purposes should be a last resort, because it is inconsistent with the goals of billing customers based on their actual usage and providing accurate billing data to customers and their commodity providers.⁴⁹⁸

The Company counters that it is implementing a "Meter Data Management System" (MDMS) in connection with MHP expansion for customers with demand greater than 500 kW.⁴⁹⁹ It says the MDMS has "a robust capability for verifying and estimating interval data," which should resolve data recording and tolerance failure issues (Tr. 1418-19, 1420-21). The Company also states that NYECC and RESA appear to be under the misimpression that the Company uses the same process for retail billing as for reporting data to the NYISO for reconciliation.⁵⁰⁰ In fact, for retail billing, when interval recorder data are invalid, missing, or anomalous, the Company estimates the customer's usage based on historical usage information (Tr. 1443-45, 1460-66; Ex. 385); it does not use load shapes. It uses load shapes, when the tolerance check fails, only for reporting data to the NYISO for reconciliation.

Turning to the related NYECC proposal that the Company establish and publish a prioritized protocol for rectifying data

⁴⁹⁸ RESA's Initial Brief, pp. 9-10. RESA states that the Company currently serves 904 large time-of-day customers with interval meters. Those customers are responsible for 3,076 MWs of load.

⁴⁹⁹ The Company's Initial Brief, p. 513.

⁵⁰⁰ The Company's Reply Brief, pp. 182-83.

aberrations, the Company states that it expects the MDMS, and the use of less complicated meter configurations for larger customers with demands of less than 1.5 MW, will resolve most of the issues with data aberrations.⁵⁰¹ NYECC rejoins that a prioritization schedule remains reasonable because the MDMS will not eliminate using average load shapes rather than actual consumption data and will not resolve many issues related to data aberrations.⁵⁰²

The Company's Customer Operations Panel testified that, although the MDMS will help resolve many of the problems associated with interval meter data gaps, it will, as NYECC notes, not eliminate all problems or the use of load shapes. In addition, the panel said the Company would be willing to participate in a collaborative effort to consider the problems and seek a resolution (Tr. 1460-68). Accordingly, we adopt the proposal for a collaborative effort to examine and resolve the issues NYECC and RESA have raised, including the issue of whether the Company should establish a prioritized protocol for rectifying data aberrations.

2. Strategic Installation of AMR

The Company proposed to:

- a. Invest \$23.679 million over two years to complete its AMR saturation program in Westchester County.
- b. Invest \$.5 million per year to replace at a rate of 3,500 per year, 93,000 existing AMR devices on meters of those who are infirm or have trouble providing meter access.
- c. Invest \$1.3 million per year for ten years to place 100,000 AMR devices on other meters to which it has not been given access for over 120 days.
- d. Invest \$1.28 million per year to install AMR devices or meters in all new and refurbished buildings.

⁵⁰¹ The Company's Initial Brief, p. 513.

⁵⁰² NYECC's Reply Brief, p. 20.

DPS Staff opposed all but the first of the Company's proposals while the NYC Government Customers supported a more expansive program for placing AMR devices on meters to which the Company has difficulty obtaining access.⁵⁰³

The judges summarized the competing considerations including costs involved, the degree to which cost savings might be achieved by the Company outside of the AMR saturation program in Westchester, the customer and public policy benefits of bills based on actual rather than estimated bills, and the potential for some or all of the planned investment becoming stranded based on whether and when we might approve the Company's Advanced Metering Infrastructure (AMI) proposal pending in another case.

Taking these considerations into account, the judges recommended that the Company be allowed to recover on the planned completion of the AMR saturation program in Westchester. They also recommended that \$34,000 per year of incremental O&M expenses plus carrying charges on an investment of \$3.08 million per year (the total investment planned by the Company) be allowed, but that these revenues be devoted solely to replacing, at an accelerated rate, 93,000 existing AMR devices that the judges understood to be obsolete. The judges stated that this would essentially maintain the status quo, much like DPS Staff's proposal to support the Company's planned investment for completing the AMR saturation program in Westchester.⁵⁰⁴

The Company excepts, arguing as follows:⁵⁰⁵

- a. The purpose of the program the judges propose be funded involves the replacement of remote reading devices with AMR meters when they fail. It used the word "obsolete" to describe the remote metering

⁵⁰³ Indeed, no party objects to the Company's proposal to complete its AMR saturation program in Westchester.

⁵⁰⁴ R.D., pp. 320-324.

⁵⁰⁵ The Company's BoE, pp. 63-64.

devices because they will be obsolete once they fail. In other words, the Company does not plan to invest more than \$.5 million per year in this single program.

- b. The judges did not give adequate attention to its other proposals based on DPS Staff concerns about a lack of cost savings and possible stranded costs, but there is record evidence to suggest the stranded cost concern is unwarranted.
- c. Adoption of the judges' recommendation would limit the Company's ability to reduce the number of estimated bills.
- d. Curtailing AMR installations in new buildings will require the Company to incur and seek recovery of incremental meter-reading costs that would have been included in its May 2008 rate filing.

DPS Staff excepts, arguing that:⁵⁰⁶

- a. The recommended decision "directs" expenditures proposed by no party.
- b. There is no evidence the Company should invest up to \$3.08 million per year to replace existing AMR devices.
- c. At most, the Company should be allowed carrying charges on \$.5 million per year for that purpose.

The NYC Government Customers except to the extent the judges did not support the Company's proposal to invest \$1.3 million per year to replace with AMR devices existing meters to which the Company has difficulty obtaining access. Its arguments are as follows:⁵⁰⁷

- a. Estimated bills obstruct state and local energy efficiency goals.
- b. From July 2004 through June 2007, approximately 32% of New York City's bills were estimates, a rate almost three times that of the Company's system average.

⁵⁰⁶ DPS Staff's BOE, pp. 69-70. DPS Staff states that the recommended decision "mistakenly" refers to the replacement of "obsolete AMR devices," and simultaneously describes the Company's proposal as one to "replace existing but obsolete remote meter reading devices..."

⁵⁰⁷ The NYC Government Customers' BoE, pp. 27-32.

- c. Advanced Metering Initiatives are being considered because they help to increase energy efficiency.
- d. Customers prefer actual meter readings over estimates because their bills are more accurate.
- e. AMR devices will reduce the number of times the Company will have to attempt to read meters that are not easily accessible, reducing labor required to read meters.
- f. DPS Staff's concerns about stranded costs are speculative at best, given that no appropriate AMI technology or comprehensive plan have been adopted for the Company, that the Company expects any AMI initiative to be implemented gradually over seven years, and that the Company's \$713 million AMI proposal, pending in another case, might never be approved.
- g. Moreover, DPS Staff's stranded cost concerns ignore the possibility that AMR technology might be upgraded to establish a virtual AMI system.
- h. Customers unable to receive actual meter reads should not be denied that right based on a belief that AMI might be in place 5-10 years from now.
- i. DPS Staff is inconsistent to support a Company investment of \$23.679 million over two years in 12% of the system (Westchester), but to oppose a \$1.3 million investment in 88% of the system (New York City).
- j. The recommended decision does not offer either justification of, or an explanation for, the recommendation against funding the Company's targeted AMR proposal.

Responding to the exceptions of the Company and the NYC Government Customers, DPS Staff argues:⁵⁰⁸

- a. With respect to hard-to-access meters, no evidence has been provided to show that the customer and public policy benefits exceed the costs that would be incurred or that such costs should be assigned to the general body of ratepayers rather than the customers who fail to provide the Company ready access to its meters.
- b. The NYC Government Customers fail to provide any evidence or otherwise explain how anyone would

⁵⁰⁸ DPS Staff's BOE, pp. 36-37.

benefit from the Company's proposal other than itself.

- c. The Company provided no record evidence to support its argument that placement of AMR meters in new construction would avoid future incremental costs for meter readers.

The NYC Government Customers also respond to DPS Staff's exceptions, contending:⁵⁰⁹

- a. Both it and the Company refuted DPS Staff's stranded cost concerns (referring to anticipated slow progress on the AMI front and the possibility the AMR equipment can be upgraded to virtual AMI).
- b. DPS Staff's concern about the \$1.3 million producing fewer savings relative to the Company's AMR saturation program is "curious" because the \$1.3 million investment in New York City is much less than the \$23.679 million investment planned for Westchester and as the \$1.3 million will provide benefits that are substantial to the customers now impacted by estimated bills.
- c. The modest cost of achieving those benefits should not be disallowed simply because labor savings would be lower compared to those in Westchester.
- d. New York City reports that electric bills for 53% of its meters were based on estimates in December 2008, a level described as an all-time high.

At a session on February 12, 2009, the day after briefs opposing exceptions were filed in these cases, we established minimal functional requirements for AMI, created a process for the development of a generic approach to the benefit/cost analysis of AMI, and required the Company to file an updated proposal for an AMI pilot project. In light of this action, additional action anticipated soon concerning AMI, and the Company's clarification that 93,000 existing AMR devices are not already obsolete, we are authorizing allowances for completion of the saturation program in Westchester and for the proposed \$.5 million annual investment in the replacement of

⁵⁰⁹ The NYC Government Customers' BOE, pp. 16-18.

existing AMI devices as they become obsolete. It is premature to fund the Company's other AMR proposals.

G. Contributions in Aid of Construction

1. DPS Staff's Proposals

DPS Staff proposed that Consolidated Edison develop and submit for our consideration a methodology for requiring a customer or developer to make a reasonable Contribution in Aid of Construction (CIAC) towards the cost of facility reinforcements necessary to serve new or added load that exceed some threshold amount.⁵¹⁰

The Company has these concerns about DPS Staff's proposal:⁵¹¹

- a. Economic development could be adversely affected because system reinforcement costs might lead a developer to go elsewhere or dissuade an existing customer from expanding its business in the Company's service territory. This contrasts with the current approach under which a broader customer base supports recovery of common costs and the region benefits from increased business and employment opportunities.
- b. Assignment of expansion costs to specific customers can be unfair because system reinforcements typically benefit more than one customer. Allocating costs and benefits fairly can be complicated.
- c. The Company is subject to federal income tax on any contribution in aid of construction. To maintain revenue neutrality, the CIAC would have to be grossed up for taxes, compounding the economic development impacts.
- d. The topic would be better addressed in a generic case with affected parties at the table beyond those that participate in its rate cases. Such a proceeding would be the proper forum for consideration of alternative approaches for ensuring that those coming on the system will provide

⁵¹⁰ DPS Staff's Initial Brief, pp. 332-33.

⁵¹¹ The Company's Initial Brief, pp. 517-20.

revenues sufficient to cover the costs incurred to serve them.

CPA opposes DPS Staff's proposal because:⁵¹²

- a. It inequitably treats new customers differently.
- b. As Consolidated Edison argues, the proposal:
 - i. Creates a barrier to economic development (Tr. 3519).
 - ii. Requires a problematic allocation between the cost of facilities required for specific load and the cost of building excess capacity to allow for future growth.
 - iii. Would not allow the Company to earn a return on those facilities, eventually leading to unacceptably low cash flow.
- c. DPS Staff's witness agreed that Consolidated Edison's concerns should be considered, but offered no guidance on how they should be addressed (Tr. 3521).

DPS Staff anticipates CPA's criticism, contending:⁵¹³

- a. Under DPS Staff's CIAC proposal, customers would pay only a portion of the necessary system upgrades; not all, as CPA claims.
- b. Once the CIAC is paid, the customer would take and pay for service just like all other customers in the class.
- c. Like any change in Commission policy, there is always a possibility that new customers will be treated differently going forward.

Responding to DPS Staff's argument that its CIAC proposal would result in more equitable allocation of costs going forward, CPA contends:⁵¹⁴

- a. New customers required to make CIAC payments would obviously pay more than existing customers otherwise similarly situated; and be forced to fund improvements to property they do not own, without the ability to finance with mortgage secured debt or

⁵¹² CPA's Initial Brief, p. 5.

⁵¹³ DPS Staff's Initial Brief, pp. 335-36.

⁵¹⁴ CPA's Reply Brief, pp. 6-7.

to recover the costs in the event of business liquidation.

- b. DPS Staff has failed to answer what "portion" of system upgrades would be paid by new customers or whether they would wind up funding future excess capacity that would be installed from time to time.

2. The Company's Proposal

The Company maintains that another way of minimizing its costs of providing service would be to afford it greater flexibility to require customers to take service at high voltage where that is most economic for the Company. This would require a change in the definition of "premises" as the term is used in the Company's tariff so, for example, a shopping center of attached stores could not use a subdivision as a way to require the Company to serve each store separately. The Company asks that its proposal along these lines be approved.⁵¹⁵

DPS Staff proposed a sample definition of "premises" to add to the Company's tariff language on its single service line obligation, intended to help the Company avoid having to serve a development by multiple service points when one would suffice (Tr. 2549). In response to the Company's concerns over the DPS Staff's proffered definition of "premises," DPS Staff notes that the Company is free to offer a different one and, since it currently has only an operational definition, should be required to include a definition of "premises" in its revised tariffs effectuating the Commission's order in these cases. The Company's filing of a recommended CIAC methodology, DPS Staff says, should also recognize the provisions and impacts of the proposed "premises" definition.⁵¹⁶

3. Discussion

DPS Staff's and the Company's proposals are correctly grounded on the fact that some new developments impose

⁵¹⁵ The Company's Initial Brief, pp. 516-521.

⁵¹⁶ DPS Staff's Initial Brief, pp. 334-35.

significant capital costs for Company facility reinforcements that benefit the individual customer or developer rather than the general body of ratepayers. Reasonable ways of limiting such ratepayer exposure are in order. That ratepayers as a whole have borne all of those costs in the past does not justify the continuation of that practice. We agree with DPS Staff that steps should be taken to permit imposition of a greater share on the individuals or groups of customers directly benefited by the capital outlays needed to serve them. Other electric utilities, including National Grid and Central Hudson Gas and Electric Corporation have tariff provisions that do so.⁵¹⁷ We will require the Company, after consultation with DPS Staff, to make a filing, within 90 days after the issuance of this order, of revised tariff language that would generically allow the Company to require a customer to make a reasonable contribution toward the cost of significant system improvements or reinforcements necessary to provide new or expanded service. The revised tariff language should include a proposed additional load level or cost level that would trigger the Company's ability to require a contribution in aid of construction. It should also include a proposed revised definition of "premises."

H. Changes to Encourage CHP/DG/Solar

The NYC Government Customers state that clean distributed generation (DG) can make a vital contribution towards energy independence and reduced greenhouse gases and other pollutants. This is evident, they say, because Congress recently extended the Renewable Energy Tax Credit, the New York State Renewable Energy Task Force recommended expanded distribution of DG in key target markets, and a goal of New York

⁵¹⁷ E.g., Central Hudson Gas and Electric Corp., PSC No. 15 - Electricity, Leaf 98, Rule 26: Unusual Conditions and Increased Loads.

City's PlaNYC is to increase DG in the Company's service territory by 800 MW by 2030.

In order to eliminate barriers to the implementation of clean DG, these parties recommend the Company be required to do the following:⁵¹⁸

- a. Promulgate rules that promote and facilitate the participation of clean DG in the load relief process. For example, the Company could provide load relief credits for generation as a function of unit size (smaller units given greater credits), number of units in the network, and reliability.
- b. Give priority to the resolution of fault-current constraints on the development of DG in parts of the Company's delivery system requiring load relief.
- c. Expedite the development of solar generation through net metering, consistent with a recently enacted state law authorizing net metering of up to 2 MW of solar and wind generation for non-residential customers.⁵¹⁹ Among other things, this would require the Company to (1) modify its protection procedures to accommodate expected growth in net metering; (2) establish processes by which clean DG can communicate with the Company's network; (3) file a comprehensive and detailed model contract and rate schedule that will minimize the need for negotiations;⁵²⁰ and (4) file semi-annual reports on progress implementing the new law.
- d. Work collaboratively with the NYC Economic Development Corporation and other interested agencies to craft a process by which district-energy arrangements may be developed in coordination with large redevelopment projects.
- e. Discontinue publication of semi-annual reports summarizing the interconnection status of DG projects, which reports are said to be incomplete and out of date. Replace the reports with a web-

⁵¹⁸ NYC City Government Customers' Initial Brief, pp. 85-88. See, also, Ex. 447, pp. 24-29.

⁵¹⁹ 2008 NY Laws, Ch. 452.

⁵²⁰ This specific proposal is an overlay on an existing mandate that required the Company to file a model contract and rate schedule late last year to implement net metering.

based interconnection system to facilitate the completion of proposed DG resources.

- f. Maximize solar photovoltaic resources, particularly in midtown Manhattan where tall buildings dominate, to help relieve T&D problems on high-load days that are frequently sunny days. Thus, for example, the Company should offer incentives for photovoltaics in day-peaking targeted areas, commensurate with the T&D benefits they provide. Such maximization would advance important national, State, and local policy initiatives.

Pace Energy and Climate Center (Pace) proposes that the Commission adopt an incentive program that would provide payments to Consolidated Edison for facilitating installation of combined heat and power (CHP) projects in its service territory. The program would have the following features:⁵²¹

- a. Incentive payments would be made after the project commences commercial operation, on a showing that the Company played a material role in facilitating its installation (one-half paid one year after commercial operation, with the balance paid two years after commercial operation).
- b. An eligible project would require: a minimum annual efficiency standard of 60%; a NYSERDA-approved audit after Consolidated Edison staff referred the project to a NYSERDA audit program; and documented evidence that the project resulted from a contact at a Consolidated Edison-sponsored outreach and education program.
- c. Payments would be tiered, with a greater \$125/kW for targeted areas where the project would enable deferral of transmission and distribution investment or have an efficiency level of 70% or more. Projects not meeting either of these criteria would yield a payment of \$70/kW.
- d. The total lifetime cost of this program would be capped at \$20 million, representing 160 to 285 MW of incremental installed CHP, depending on the tiers into which projects fell.

⁵²¹ Pace's Initial Brief, p. 2 and Ex. 365, pp. 19-23.

- e. Payments would be recovered in revenue requirement from all customers, given the benefits to all from greater CHP deployment.

Pace contends that this CHP incentive program should be implemented as a reasonable means to stimulate deployment within the Company's service area, because:⁵²²

- a. Consolidated Edison is familiar with its customer base and in a good position to play a more pro-active role in identifying and facilitating potential CHP projects that best meet its system planning needs.
- b. CHP provides significant benefits to Consolidated Edison customers since it: promotes greater energy efficiency; reduces the need to invest in T&D facilities; increases reliability by having more on-site generation during outages, and reduces greenhouse gas emissions.
- c. There is great potential for CHP within Consolidated Edison's service territory: about 3,200 MW, or 38% of the total statewide technical potential.⁵²³
- d. Experience in other jurisdictions, like Connecticut, suggests that the availability of incentives produces tangible results in CHP deployment.

Pace opposes Consolidated Edison's suggestion that Pace's CHP proposal should instead be considered in Case 08-E-1018, concerning Standard Interconnection Requirements, because:⁵²⁴

- a. The purpose of its CHP proposal is to change the Company's corporate culture by giving it an economic incentive to facilitate CHP.
- b. Interconnection is not a barrier to CHP projects.
- c. The interconnection proceeding does not involve economic incentives to change corporate culture on CHP.

⁵²² Pace's Initial Brief, pp. 5-7 and Ex. 365, pp. 4-5.

⁵²³ "Combined Heat and Power Market Potential for New York State," NYSERDA Final Report 02-12, www.nyserda.org/chpnys/market.asp.

⁵²⁴ Pace's Initial Brief, pp. 7-8.

Pace also challenges Consolidated Edison's suggestion that the CHP incentive proposal should be considered in the Energy Efficiency Portfolio Standard (EEPS) proceeding, because:⁵²⁵

- a. CHP does not fit neatly into the category of energy efficiency measures, given that it provides a source of electric generation.
- b. It does not fit well in the category of distributed generation, since it offers energy efficiency benefits.
- c. A general rate case is an appropriate forum to consider a CHP incentive mechanism, since costs of incentive payments are proposed to be included in calculating revenue requirement in subsequent general rate cases.
- d. The CHP mechanism is consistent with the Commission's policy on incentives to "promote better program performance" and "motivate utilities to pursue energy efficiency programs as a resource option."⁵²⁶

In its Initial Brief (pp. 2-3), Pace modifies its incentive proposal to make it bi-directional, like NYECC's. Thus, if Consolidated Edison's actual performance in a year fell below 75% of the prior two-year average, the Company would be subject to a negative adjustment for the difference between the actual new CHP installations and the 75% threshold level. Pace does not say whether the negative adjustment should be based on the \$125/kW tier or the \$70/kW tier of the positive side of its proposed incentive program.

Pace also proposes that the Commission consider a proceeding to evaluate comprehensively the interrelationships among Consolidated Edison's electric, steam, and gas

⁵²⁵ Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Concerning Utility Financial Incentives (issued August 22, 2008), p. 34.

⁵²⁶ Pace's Initial Brief, pp. 7-8.

operations.⁵²⁷ In addition to seconding NYECC's point that some CHP projects might be seen by Consolidated Edison as having negative implications for its steam system, Pace argues that the steam system would provide potential benefits to the electric system by driving chillers to reduce air conditioning loads and thus summer system peaks; and that the Company's natural gas system could benefit from increased penetration of CHP.

NYECC proposes an incentive program for DG and CHP that would provide bi-directional incentives to Consolidated Edison, because of the benefits of DG/CHP in high-rise buildings within the area served by the Company's steam system (Tr. 4598).⁵²⁸ NYECC also believes Consolidated Edison may need incentives to facilitate DG/CHP installations because some potential projects may be perceived as having negative effects on the Company steam system (Tr. 4598), a view supported by Pace.⁵²⁹ NYECC's bi-directional incentive program would have these features:⁵³⁰

- a. If Consolidated Edison maintains a level of annual new CHP installations in its service territory from 75% to 125% of the prior two-year average, no incentive payment would be due to or owed by the Company.
- b. If annual new CHP installations exceed 125% of the prior two-year average, the Company would receive an incentive payment of \$100/kW for the actual number of kW of installed CHP exceeding 125% of the prior two-year average.
- c. If annual CHP installations fall below 75% of the prior two-year average, Consolidated Edison would be liable for a negative adjustment of \$100/kW for the difference between the actual number of installed kW of CHP and 75% of the prior two-year average.

⁵²⁷ Ibid., p. 4

⁵²⁸ NYECC's Initial Brief, pp. 31-33.

⁵²⁹ PACE's Initial Brief, p. 4.

⁵³⁰ NYECC's Initial Brief, pp. 31-33.

Joint Supporters maintains that the arguments in support of measures to further CHP opportunities for large projects also apply generally to residential micro-CHP systems (25 kW or less).⁵³¹ Specifically, it supports New York City's recommendation that Consolidated Edison should prioritize resolution of fault-current constraints at substations in areas requiring load relief.⁵³² It also echoes NYECC's and Pace's calls for an incentive program to encourage the Company's facilitation of DG/CHP deployment, but favors a program like NYECC proposes, which would provide a positive incentive only upon reaching a particular level of system installations, rather than one that would provide payments on a "per project" basis, as Pace proposes.⁵³³

Joint Supporters also makes several proposals never introduced or explored on the record.⁵³⁴ First, it states that Consolidated Edison should be required to develop a simplified application for micro-CHP systems available for one- to four-family homes and businesses, because the systems are standardized and do not require the same level of review as larger customer systems; and that external disconnect switches should not be required, since they are inverter-based. Joint Supporters also contends that various detailed changes to Rider U should be made to allow use of DG/CHP systems. In addition, it urges that an on-line application and project management process be established for DG/CHP systems. Finally it states that any total resource cost test requirements should include environmental benefits as part of the calculation because environmental issues are of paramount concern in New York now.

⁵³¹ Joint Supporters' Initial Brief, p. 2.

⁵³² Ibid., at 3.

⁵³³ Ibid., at 4-5.

⁵³⁴ Ibid., at 3-5.

Anticipating various proposals by the NYC Government Customers, NYECC, and Pace related to the interconnection of DG, the Company states:⁵³⁵

- a. The proposals are not necessary as not one of these parties described a single instance in which the Company failed to work cooperatively with a customer seeking to install DG.
- b. The proposals are more properly raised and addressed in Case 08-E-1018, concerning standard interconnection requirements, Case 07-M-0548, the EEPS proceeding which has a working group concerning the role of DG in achieving the State's energy efficiency goals, or Case 03-E-0188, the Renewable Portfolio Standards proceeding that is considering the role of solar in New York City.

DPS Staff supports the Company's suggestion that the interconnection issues Pace, the NYC Government Customers, and NYECC raise for DG be considered in Case 08-E-1018, on interconnection standards, for the sake of uniformity.⁵³⁶

In response to the Company, the NYC Government Customers state:⁵³⁷

- a. No one alleged that the Company has failed to cooperate with any particular customer because that is not the problem. The NYC Government Customers' recommendations are designed to reduce or eliminate barriers that are embedded within the interconnection process that affect all customers generically.
- b. The other proceedings the Company cites are not preferable for considering the NYC Government Customers' DG proposals because:
 - i. Case 08-E-1018 on standard interconnection requirements has had little activity to date and there has been no indication of any Commission intent to develop standardized DG interconnection rules or whether the rules to be developed would resolve the issues

⁵³⁵ The Company's Initial Brief, pp. 520-521.

⁵³⁶ DPS Staff's Reply Brief, p. 103.

⁵³⁷ NYC Government Customers' Reply Brief, pp. 28-31.

raised here. In addition, it is impossible to predict when any standardized rules would be promulgated.

- ii. The EEPS proceeding is not appropriate for consideration of these DG issues because it is focusing on identification of potential new programs to be developed, not on the refinement of an existing program, which is what the NYC Government Customers and other parties seek here.
- iii. The renewable portfolio standard proceeding is not appropriate because the DG interconnection issues raised here focus more broadly in a fuel source neutral manner on DG, which might include many natural gas fired units, not just renewable resources, and gas-fired units are not eligible to participate in the RPS program.

Joint Supporters on reply states its support for the NYC Government Customers' proposals for improved, more complete and consistent and web-based periodic disclosure of information on the status of clean DG projects, which, it says, contrary to the Company's claim, are not being addressed in EEPS Working Group VIII. It also supports the NYC Government Customers' proposal for semi-annual Company reporting on implementation of net metering. In addition, Joint Supporters denies the Company's claim that resolution of fault current constraints is being addressed in EEPS Working Group VIII.⁵³⁸

In its Reply Brief, Pace supports Joint Supporter's recommendation that: (a) the Company should develop a simplified application process for micro-CHP systems (25 kW or less); and (b) the Company should modify Rider U in a manner that permits DG/CHP to be included in the program.⁵³⁹

Pace opposes the new suggestion in the Company's Initial Brief that the issue of an incentive program for

⁵³⁸ Joint Supporters' Reply Brief, p. 2.

⁵³⁹ Pace's Reply Brief, p. 6.

facilitating CHP installation be referred to the Renewable Portfolio Standards, inasmuch as:

- a. The issues currently being considered in the RPS proceeding are unrelated to that of a financial incentive program for the Company to facilitate CHP installation.
- b. CHP is not currently the subject of a procurement obligation under the RPS scheme.
- c. Pace's incentive program proposal is designed in recognition of the Company's own familiarity with its customer base and the steps it can reasonably take to facilitate CHP installation in its own service territory.
- d. Pace proposes that incentive payments to the Company be financed as part of its general revenue requirement, not from RPS-related funding.

We believe the Company continues to work effectively, in the wake of an exhaustive formal study completed several years ago, to replace fault-current breakers, consistent with the Company's unique and complex system design, physical and scheduling limitations, and reliability criteria. The Company has been replacing at least 60 breakers a year. We see no need for additional study of this matter. With respect to Rider U issues, Joint Supporters failed to raise them in a timely manner in this proceeding. In any event, they do not belong in this rate case, but in a proceeding specifically focused on changes to Rider U, such as the one that was the subject of notice and comment during the first quarter of this year.⁵⁴⁰

Several other issues raised by the parties concerning facilitation of an increase in the amount of clean DG on the Company's delivery system have been the subject of important developments since they filed their briefs. We have now issued newly revised Standard Interconnection Requirements (SIR) for DG

⁵⁴⁰ E.g., Cases 08-E-0176 and 08-E-1463, Revisions to Rider U - Distribution Load Relief Program, Untitled Order (issued April 8, 2009).

of 2 MW or less.⁵⁴¹ Among other things, the modifications to the SIR implement New York's newly expanded net metering law, eliminate the external disconnect switch requirement for inverter-based systems of 25 kW or less, and establish an expedited, Internet-based interconnection application process for systems of 25 kW or less, an Internet-based system to provide customer-generators and contractors with up-to-date information on the status of applications, and a requirement for semi-annual reporting by utilities to facilitate monitoring of compliance and timeliness of interconnection application processing.

In our judgment, the Renewable Portfolio Standards proceeding provides an appropriate vehicle for consideration of ways to increase solar generation in the Company's service area. In addition, on February 27, 2009, the Company filed a proposed solar energy pilot program, which DPS Staff is currently reviewing. The pilot program includes initiatives for customer sited distribution system solar projects, Company property sited solar installations, and a request for proposals process to solicit large-scale solar projects in its service territory. NYSERDA is already conducting a program under SBC 3 that provides opportunities for expansion of CHP penetration. The several proposals in this proceeding for additional incentives to promote greater DG penetration in the Company's service area appear to be insufficiently well-developed in a number of respects. In view of these considerations, we decline to adopt additional DG proposals presented here.

⁵⁴¹ Case 08-E-1018, Rules and Regulations on Interconnection and Operation of Customer-Owned Generation, Order Modifying Standard Interconnection Requirements (issued February 13, 2009).

I. Outreach & Education Reporting

DPS Staff proposes that Consolidated Edison be required to submit an annual Outreach and Education (O&E) plan to the DPS Director of Consumer Services at least 90 days before implementation, for expedited review and refinement of program content and budget in a collaborative process with DPS Staff and other parties (Tr. 4705). DPS Staff maintains:⁵⁴²

- a. The Company admits that it files O&E plans with DPS Staff twice annually and does not dispute that those filings should continue (Tr. 1324).
- b. The Company also acknowledges that its O&E plans incorporate input from DPS Staff and from other agencies (Tr. 1325).

The Company disagrees, arguing:⁵⁴³

- a. DPS Staff acknowledges that the Company's \$3.6 million outreach and education budget is reasonable and in line with past expenditures.
- b. The Company's practice is to submit such plans to DPS Staff.
- c. DPS staff is not bashful about making its views known about what messages should be promoted.
- d. Past communications took place well in advance of program implementation.
- e. Consultations within 90 days of implementation are too late in the process. The Company would lack sufficient flexibility to deal with issues of current importance to consumers if it had to file a plan months in advance of implementation.

DPS Staff replies:⁵⁴⁴

- a. DPS Staff agrees with the Company that collaboration with other parties should occur during development of an O&E plan, not after one is filed and the Company is preparing for implementation.

⁵⁴² DPS Staff's Initial Brief, pp. 336-37.

⁵⁴³ The Company's Initial Brief, p. 521; the Company's' Reply Brief, pp. 185-86.

⁵⁴⁴ DPS Staff's Reply Brief, pp. 104-05.

- b. DPS Staff is not proposing submission of O&E plans for Commission approval, but only for DPS Staff review and opportunity to provide feedback to the Company for reflection in the plans along with input from other parties.

This proposal appears originally to have contemplated that consultation with DPS Staff and other parties occur during the 90-day or longer period after the Company files its O&E plan. In its reply brief, however, DPS Staff seems to abandon that position and now concedes that collaboration should occur before the plan is filed with the Director of Consumer Services. The Company already submits its tentative O&E plans to DPS Staff for review and comment before implementation. No other party has expressed support for DPS Staff's proposal or indicated any interest in reviewing and commenting on the Company's draft plans in a collaborative process. Since the proposal's intended beneficiaries have no interest in it, we see no need to change the current process and will not adopt DPS Staff's proposal.

J. Process for Aggregating / Using Building Usage Data: Access to Information for Building Owners

The NYC Government Customers urge us to direct that a working group be established within 30 days of the final order in this case.⁵⁴⁵ The purpose of the working group would be to help ensure the Company will cooperate in a possible New York City initiative to require qualifying buildings to report annually on their energy and water usage. The required reporting is described as part of a "benchmarking" process intended to help building owners consider the energy performance of their buildings and to make it easier for potential renters and buyers to assess the energy performance of properties they are considering. That, in turn, is expected to help the City meet its goals for increased energy efficiency and decreased air

⁵⁴⁵ NYC Government Customers' Initial Brief, pp. 89-92.

emissions. The NYC Government Customers specify several issues that they wish the collaborative discussion to address.

The Company and NYECC indicated during the hearings that they would participate in the working group. The Company, however, expressed concern about divulging the confidential financial information of individual customers. The NYC Government Customers suggest that this concern is not valid because the goal is to obtain aggregate energy usage data from the Company for buildings and, in any event, that this is an issue for consideration by the working group.

NYECC requests that the Company be required to give building owners access to tenant electric load information for the purpose of maximizing energy efficiency efforts and attaining New York City and New York State efficiency goals, because:⁵⁴⁶

- a. Building owners and managers need unlimited access to electric load profiles of tenants to ensure safe and reliable electric supply within their buildings (Tr. 4590).
- b. Many existing leases do not include specific provisions allowing building owners and managers to require tenants to provide this information, so the only practical way to obtain it is from the Company (Tr. 4590).
- c. Confidentiality of customer financial data or electric bills does not have to be violated; NYECC seeks disclosure only of load consumption data, which might not be confidential (Tr. 4608-10).
- d. Building owners are concerned with: (a) their ability to meet reporting requirements for the EPA portfolio manager, Energy Star applications, and pending New York City legislation on building profile data; and (b) knowing how electricity flows through building systems, to ensure safe and reliable energy use (Tr. 4610).

The Company confirms that it is willing to discuss issues associated with providing landlords with data about their

⁵⁴⁶ NYECC's Initial Brief, pp. 33-34.

tenants' energy usage, provided the confidentiality of customer usage information and the recovery of costs to be incurred in developing and implementing such a program are on the agenda.⁵⁴⁷ The Company is also concerned that aggregation of information on a per-building basis might not be sufficient to protect confidentiality in the case of premises occupied by a single tenant or one very large tenant and a few smaller tenants, and that this concern would also have to be addressed.⁵⁴⁸

DPS Staff responds to NYECC's proposal stating that Consolidated Edison and interested parties should submit a proposal, within 60 days after our rate order in this case, that addresses concerns identified by NYECC and the Company, such as the billing system's capability, a process for sharing aggregate building energy data, the treatment, confidentiality, and type of customer information that may be released, frequency and method of delivery of information, and method of cost recovery. NYECC concurs.⁵⁴⁹

In response to DPS Staff's suggestion, the NYC Government Customers contend that a collaborative process would be a more productive and efficient method to develop the issues than a formal Commission review of written proposals from multiple parties.⁵⁵⁰ They believe a collaborative process will help sharpen the issues and perhaps lead to compromise many can support and might avoid a premature hardening of positions that could slow or stymie resolution of the issues. The Company agrees with the NYC Government Customers that 60 days would be an insufficient period within which to develop a proposal for addressing the issues. It suggests that, since both the NYC

⁵⁴⁷ The Company's Initial Brief, pp. 521-22.

⁵⁴⁸ The Company's Reply Brief, p.186.

⁵⁴⁹ DPS Staff's Initial Brief, pp. 337-38. NYECC's Reply Brief, p. 22.

⁵⁵⁰ NYC Government Customers' Reply Brief, pp. 32-33.

Government Customers and the Company envision a collaborative process, the goal would be better served by giving the Company a 60-day period to perform an initial analysis of requirements before meeting with interested parties, with a deadline for submission of a proposal to the Commission subsequently developed by the group.⁵⁵¹

The only real issue among the parties is timing for initiation of the collaborative and submission of a proposal to resolve concerns considered in it. The 60-day period that DPS Staff suggests for submitting a proposal resolving the issues seems insufficient to allow proper consideration and negotiation of the issues among interested parties. The Company's counterproposal that it be allowed 60 days from the date of our decision here to analyze the issues and initiate the collaborative, with the deadline for submission of a proposal to be developed by the group, appears reasonable. We adopt it.

K. Clean Air Act and Regional Greenhouse Gas Initiative (RGGI) Costs

The judges recommended that the Company be allowed to recover outside base rates approximately \$5.064 million to offset Clean Air Act Section 185 fees for the emission of nitrous oxides and volatile organic chemicals in a severe non-attainment area.⁵⁵² They also recommended that, pending any decision to provide for their recovery otherwise, the Company be permitted to recover in its Market Supply Charge and Market Adjustment Clause (MSC/MAC) an estimated \$10.8 million per year for the Company to purchase 2.1 million CO₂ allowances at an estimated cost of \$5 per ton. The Company ultimately declined to seek recovery of any RGGI costs associated with out-of-state

⁵⁵¹ The Company's Reply Brief, p. 187.

⁵⁵² The Company clarifies on exceptions that this is a total Company estimate, a share of which should be borne by its steam department.

purchases and, thus, the recommended decision does not discuss that topic.

On exceptions, the Company argues that the revenues for the Clean Air Act fees should be recovered through the MSC/MAC. It states that no better alternative has been offered to date.⁵⁵³ DPS Staff does not reply.

DPS Staff excepts as to RGGI costs, however, suggesting the judges' recommendation amounts to a "blank check," that a recommendation on a specific cost recovery mechanism was not provided, and that MSC/MAC should be used only for recovery of RGGI costs associated with the Company's retained generation. The method for recovering any RGGI costs for purchases from others' plants should be determined at a later date, states DPS Staff, once the Company demonstrates the certainty and magnitude of such costs.⁵⁵⁴

The Company replies that DPS Staff's exception is of no account because the Company is proposing recovery at this time through the MSC/MAC of only those RGGI costs to be incurred in connection with its own generation.⁵⁵⁵

It appears that DPS Staff understood the judges to be recommending relief on RGGI costs beyond what was being requested by the Company. However, the only disputed issue before the judges concerned whether to adopt the Company's MSC/MAC recovery proposal for RGGI costs for its self generation or whether to put off to the future a decision on that request, as had previously been proposed by DPS Staff. The judges recommended the Company's proposal for recovery of RGGI costs associated with the Company's retained generation only (i.e., approximately \$10.08 million per year) and nothing more and DPS Staff now agrees with that recommendation. DPS Staff's

⁵⁵³ The Company's BoE, pp. 64-65.

⁵⁵⁴ DPS Staff's BoE, p. 70.

⁵⁵⁵ The Company's BoE, pp. 79-80.

exception is moot. There is no dispute concerning Clean Air Act fees and they, too, may be recovered through the MSC/MAC.

L. Business Incentive Rate Lost Revenue

The Company had \$3.339 million of net-of-tax Business Incentive Rate lost revenues, including interest, for the period November 2003 through May 2004. There were issues in these cases about whether the Company was previously authorized to defer this amount and about whether the \$3.339 million should be included in rate base pending a final determination about whether the \$3.339 million was properly calculated.

The Company and DPS Staff ultimately agreed the \$3.339 million should be excluded from rate base for now, pending a separate evaluation of how the \$3.339 million was calculated. The judges recommended that the separate review, if feasible, be conducted in time so that the results could be reflected in the final decision in these cases.⁵⁵⁶

DPS Staff states that the Company's proposal to include these lost revenues in rate base in its last electric rate case was rejected because of the Company's failure to prove that it had been authorized to defer revenue losses associated with Business Incentive Rate discounts in the identified period.⁵⁵⁷ As such a demonstration has still not been provided almost one year later, and as no further documentation for further evaluation has been filed by the Company, DPS Staff continues, it seems highly unlikely that any separate review will be conducted and completed prior to our final decision in these cases.

The Company does not reply.

Two issues presented concern whether the Company was allowed to defer a specific type of lost revenues in a specific

⁵⁵⁶ R.D., pp. 326-327.

⁵⁵⁷ DPS Staff's BoE, p. 71.

period and, if so, whether in fact the lost revenues deferred by the Company are consistent with the deferral authorization. The Company's initial brief⁵⁵⁸ describes the relevant deferral authorization and DPS Staff did not reply. DPS Staff cites Tr. 2757 for the proposition that the Company did not previously receive the requisite authorization. While BIR revenues are discussed at that page, the issue of deferrals is not. In sum, the record establishes that the Company was authorized to defer lost BIR revenues in the relevant period of November 2003 through May 2009.

On the other hand, DPS Staff is correct that the Company has not provided the information necessary for us to determine if the lost BIR revenues deferred by the Company are consistent with the prior authorization. Consistent with the agreement of the Company and DPS Staff, the requisite evaluation will take place after the Company provides the necessary information. A final decision will be made in the ordinary course of business thereafter.

M. Compliance with Public Service Law §66(19)

The judges reported on the Company's compliance with the recommendations set forth in the Independent Audit of Consolidated Edison Company of New York, Inc.'s Emergency Outage Response Program, dated October 24, 2007.⁵⁵⁹

Pursuant to PSL §66(19), we find that 26 of 62 recommendations were satisfied as of June 2008, that target dates for compliance with most other recommendations fall in 2009, and that compliance with a smaller number of recommendations is expected in 2010-2011. DPS Staff will continue to monitor the Company's progress and report any deficiencies.

⁵⁵⁸ Pp. 524-25.

⁵⁵⁹ R.D., p. 330.

N. DOJ Investigation

Arrests resulting from a Department of Justice (DOJ) investigation were announced one week after the recommended decision was issued.⁵⁶⁰ Accordingly, the recommended decision does not discuss the ratemaking implications of that investigation.

In its brief on exceptions, the Company:⁵⁶¹

- a. Expresses shock and outrage upon learning that ten active employees and one retired person were arrested on January 14, 2009 for allegedly accepting kickbacks and inflated invoices from a contractor who performed work for the Company.
- b. Reports that it is taking steps to further mitigate the risks of such illegal activities, including the hiring of an independent firm with fraud investigation experience to conduct a review.
- c. Advises that it will seek restitution from those involved as well as reimbursement under its crime insurance policy.
- d. Estimates on a preliminary basis that the electric revenue requirement impacts associated with the illegal activities amount to about \$.28 million per year.
- e. Asserts that its practices and procedures are reasonable and prudent and that these illegal acts were beyond its control.
- f. Offers to accept a temporary disallowance, subject to later collection, of \$2.8 million per year, or approximately ten times its preliminary estimate, pending a full investigation of the full extent of the illegal acts as well as its culpability for some or all of such costs.
- g. Notes that, pursuant to the 2008 Rate Order, it is recovering over ten years about \$237 million per rate year in carrying charges, subject to refund, on capital expenditures previously incurred.

⁵⁶⁰ Additional arrests were announced in mid-April 2009.

⁵⁶¹ The Company's BoE, p. 38, n. 32.

CPB replies that the Company's proposal is wholly inadequate and premature given that a thorough investigation has not yet been completed.⁵⁶²

Addressing the same topic, DPS Staff:⁵⁶³

- a. Reports that preliminary indications are that there were over \$1 million of kickbacks since 2004 and that there is some information suggesting kickbacks began in 2000 or 2001.
- b. Describes the illegal activities as involving the offering of work outside a competitive bidding process, inflated pricing after a contract award, payments for work not performed, back dated billing, and the distribution of bid specifications to some contractors in advance of a request for proposals.
- c. Points out that those arrested held high level supervisory positions in the Company's construction management and project payment review and approval processes.
- d. States that there are indications that the Department of Justice investigation is continuing and that more contractors may be involved.
- e. Explains that the recent allegations make it impossible for DPS Staff to attest to the accuracy of the Company's historic information and projections in these cases as to capital expenditures, removal costs, interference expenditures, and site investigation and remediation costs.
- f. Proposes that to protect ratepayer interests, a complete and thorough investigation be initiated and that, pending the results of that investigation, that the \$236.7 million per year currently being recovered by the Company through the Rate Adjustment

⁵⁶² CPB's BOE, p. 2.

⁵⁶³ DPS Staff's BOE, pp. 73-74. NYECC raises many of the same points and expresses its expectation that these and any related matters will be fully investigated. It does not propose any actions to be taken in these cases. NYECC's BOE, pp. 16-17.

Clause (adopted in the 2008 Rate Order) be augmented.⁵⁶⁴

- g. Suggests that it lacks adequate information to propose a specific dollar amount for such augmentation.
- h. Urges that we be conservative and limit any revenue increase to an austerity budget level with all incremental revenues recoverable through the Rate Adjustment Clause.

In its brief opposing exceptions, CPB agrees with DPS Staff on points “e” through “h” immediately above.⁵⁶⁵

Westchester refers to the DOJ investigation and argues that the allegations raise serious questions about the Company’s oversight of its projects and the size of the “required” capital program.⁵⁶⁶

The Company replies to DPS Staff and others, stating that it does not oppose the concept of temporary rates being set for a reasonable but limited amount. It contends, however, that there is no basis for applying such treatment to the majority of its Rate Year costs that are not implicated by this unfortunate development.⁵⁶⁷ Elsewhere, it notes that the published agenda for the February 12, 2009 open session makes clear that the anticipated investigation of these matters would soon be (and now is) under way.

There is an ongoing investigation by the Department of Public Service concerning transmission and distribution plant placed in service during the 2005-2008 Rate Plan. There is also another ongoing investigation of the implications of alleged

⁵⁶⁴ Id. Contrary to a statement by the judges, DPS Staff points out that rates subject to the Rate Adjustment Clause are not temporary rates as that term is used in the Public Service Law. DPS Staff’s BoE, pp. 71-73.

⁵⁶⁵ CPB’s BoE, p. 2.

⁵⁶⁶ Westchester’s BoE, pp. 2-3.

⁵⁶⁷ The Company’s BoE, pp. 84-85.

illegal activities involving numerous Company personnel starting as early as 2000 or 2001, and about how any such activities might have affected the Company's capital and operation and maintenance expenditures during that time.⁵⁶⁸ We have no preconceived notions about how either of these investigations will turn out. Accordingly, the Company continues to recover carrying charges on all related investment and there has been no adjustment to the Company's O&M expenses on account of either investigation.

At the same time, we need to maintain flexibility to disallow unreasonable costs in the event either or both ongoing investigations establish such a disallowance is warranted. To that end, we have evaluated a range of possible outcomes for the two investigations in light of the \$236.7 million per rate year currently being recovered through the Rate Adjustment Clause. At this point, we conclude that updating that amount, to reflect known changes in the cost of capital, updated deferred carrying charges, and amortization of deferred carrying charges, reasonably maintains the flexibility we need if either or both of these investigations establishes that some adjustment is warranted. Accordingly, the Company is directed to increase the amount to be collected per rate year through the Rate Adjustment Clause from \$236.7 million to \$254.4 million per rate year. Specific ordering language is set forth below.

XII. CUSTOMERS' ABILITY TO PAY

A. Introduction

This section concerns arguments to the effect that the revenue increase is simply too large, especially in the context of the current economic downturn. The arguments concern the nature and extent of the current economic downturn (economic

⁵⁶⁸ Case 09-M-0114, Consolidated Edison Company of New York, Inc. - Prudence of Certain Capital Program and Operation and Maintenance Expenditures.

impacts in general) and several competing options (the proposed options) for minimizing customer bill impacts. The pertinent background and arguments are summarized first, followed by one discussion.

B. Economic Impacts in General

The judges observed that numerous parties had expressed concern about the customer impacts of the Company's proposed delivery service revenue increases. However, none of the parties had provided any evidence about the impact of the economic downturn on customers' collective ability to pay higher rates. The judges said that they did not intend to suggest that customers are not affected by the economic downturn, only that the evidentiary record provides no clear picture of how and the extent to which they are affected.⁵⁶⁹

The judges also discussed the Company's contention that the bill impacts of its proposed delivery service revenue increase would be reasonable because of forecast reductions in electric commodity prices in the Rate Year. The judges would not give much weight to the Company's latest forecast of commodity prices because those prices are not economically regulated and can be volatile.⁵⁷⁰ Earlier in the case, moreover, when commodity costs were expected to continue to increase, the Company had argued that commodity costs should be ignored when setting delivery rates.

The judges also cautioned that concern about bill impacts is not a reasonable basis for determining any element of the Company's minimal but reasonable cost of electric delivery service. Accordingly, they recommended that we consider separately from our cost of service determinations, and one time only, the question of whether the Company's revenue requirement

⁵⁶⁹ R.D., pp. 9-10.

⁵⁷⁰ Id., p. 11.

should be based solely on the Company's minimal but reasonable cost of providing electric delivery service in the Rate Year or whether other factors—including customers' ability to pay—should also be considered.⁵⁷¹

NYPA excepts, asserting that the judges improperly "disposed of all arguments about economic impacts." Its reasons are as follows:⁵⁷²

- a. The judges have it backwards. The presumption should be that ratepayers' ability to pay has been and will continue to be negatively affected by the ongoing economic crisis.
- b. There is no evidence in the record to suggest ratepayers are better able to pay in these difficult times.
- c. Judicial notice should be taken of the facts that the Federal Reserve recently signaled that the recession might be deeper and longer than previously expected, that non-farm unemployment nationally is 7.2% and is expected to climb through 2010, and that consumer confidence nationally declined to a "new all-time low" in December 2008 based on deteriorating economic conditions through the fourth quarter of 2008.
- d. Judicial notice should also be taken of the facts that the recession commenced in December 2007 (following 73 months of expansion) and that the judges' recommended 17% T&D revenue increase would follow an increase of more than 20% in April 2008.
- e. We should exercise our judgment to strike an appropriate balance between what New York ratepayers can reasonably afford and what the Company has proven that shareholders need.

The County argues that the judges correctly acknowledge our statutory obligation to balance "just and reasonable rates" with the provision of "safe and adequate service." However, it suggests the judges accorded too much

⁵⁷¹ Id., pp. 9, 234, and 331-332.

⁵⁷² NYPA's BoE, pp. 7-9.

weight to how rating agencies might react.⁵⁷³ The County also asserts that:⁵⁷⁴

- a. A recession is the worst time to saddle businesses with additional costs.
- b. It is safe to assume that judicial notice can be taken of the fact that the current economic climate is forcing businesses to contract or close.
- c. The cost of electricity is one of several factors that can negatively affect a business.
- d. Businesses are closing every day and moving out of the Company's service territory and some of this can be blamed on the cost of electricity.
- e. Based on a New York Times article in January 2009, unemployment rose to 7.2% in New York City and to 5.7% in Westchester in December 2008.
- f. These factors must and should be taken into account.
- g. If the recommended decision is adopted, delivery service rates will have increased by more than 50% over five years. This is severely disproportionate compared to inflation of 13.39% over the same period.
- h. Volatility in commodity markets exacerbates the impacts of delivery revenue service increases. For example, the cost of New York Independent System Operator (NYISO) energy in New York City jumped from less than 8¢/kWh in July 2007 to over 14¢/kWh in July 2008, an increase of 75%.
- i. It would not be reasonable to assume lower commodity costs in the Rate Year will ameliorate bill impacts, because it is anticipated any such hiatus will be temporary.

As to economic impacts generally, the Company responds as follows:⁵⁷⁵

- a. As discussed in the recommended decision, general intuitive statements about a declining economy do

⁵⁷³ Westchester's BoE, pp. 1-2.

⁵⁷⁴ Id., pp. 3-6.

⁵⁷⁵ The Company's BoE, pp. 80-83.

not provide a legal basis for a downward adjustment to the Company's revenue requirement.⁵⁷⁶

- b. The judges already considered the impact of the economy to the extent they attempted to ascertain the minimal but reasonable costs of electric delivery service.
- c. The Company forecasts a decline in commodity (energy and energy related) costs. As these comprise in excess of 60% of its full service customers' electric bills, such reductions will offset in whole or in large part any electric delivery service rate increase.⁵⁷⁷
- d. Arguments to the effect that the judges gave too much weight to the interests of shareholders should be rejected. The courts have rejected suggestions that shareholder interests not be considered.⁵⁷⁸

C. The Options

1. A Macro Adjustment to the Company's T&D Investment and Expenses and the Austerity Budget Proposal

A big dispute between the Company and DPS Staff as to projected T&D plant investment concerns whether the Company will invest as much capital as it forecasts for various projects and programs. This dispute is discussed in Section IX (A)(1)(b) above. The NYC Government Customers raised a slightly different issue, having to do with whether rates should be set in a manner intended to reduce the amount the Company will invest in T&D plant in order to ameliorate rate impacts. Specifically, the NYC Government Customers proposed that 8% of all of the

⁵⁷⁶ Id., p. 81, citing Cohalan v. Gioia, 88 A.D. 2d 722, 723 (3d Dept. 1982). That opinion notes that the 1981 Statement of Policy Concerning Evidence of Economic Impact in Rate Cases properly recognizes that economic hardship on customers may not justify reducing rates below the minimum necessary for a utility to recover its prudent costs, including the cost of capital.

⁵⁷⁷ Full service customers purchase delivery and commodity from the Company. Retail access customers purchase delivery service from the Company and commodity service elsewhere.

⁵⁷⁸ Id., p. 82, citing Abrams v. PSC, 62 A.D. 2d 205 (1986).

Company's' planned T&D capital and O&M expenditures be disallowed, reducing annual revenue requirement by \$14 million and \$11 million, respectively, for a total of approximately \$25 million. Westchester separately proposed an overall 15.5% reduction in the Company's T&D capital construction program, the effect of which would be to reduce revenue requirement by approximately \$45 million per year.

As discussed in some detail above, the judges offered firm recommendations on the T&D investment disputes between the Company and DPS Staff, because they affect the minimum reasonable cost of providing electric delivery service. As to the proposals of the NYC Government Customers and Westchester, the judges:⁵⁷⁹

1. Noted that an 8% downward adjustment to the Company's planned T&D capital investment was adopted in the 2008 Rate Order.
2. Acknowledged the Company's claim that its original revenue request here was ameliorated by \$426 million and that its construction budget already reflects deferment of \$155 million of needed work.
3. Recommended that all cost of service determinations be made first followed by separate consideration of the pros and cons of all alternatives presented for setting rates based on considerations other than costs.

While the judges recommended that these alternative proposals be considered separately, the judges themselves did not go through that process. Accordingly, they offered no firm recommendation either in support of or in opposition to the proposals of the NYC Government Customers and Westchester.⁵⁸⁰

⁵⁷⁹ R.D., p. 271.

⁵⁸⁰ That the cost of service calculations attached to the recommended decision did not reflect the proposed adjustments was not intended to imply any recommendation on these proposals.

It appears that the Company understands the judges to have recommended some sort of macro adjustment and it excepts. The Company argues:⁵⁸¹

- a. The judges' recommendation to consider separately some macro adjustment is counter-intuitive given the extent to which the recommended decision focuses on determining the minimal but reasonable cost of electric delivery service. Any downward adjustment from there would result in rates that are too low.
- b. There is precedent to the effect that it would be plainly incorrect economically and clearly illegal [to] deliberately set rates below a utility's cost of service because the Company's customers are having difficulty paying their bills.⁵⁸²
- c. The Statement of Policy Concerning Evidence of Economic Impacts in Rate Cases permits parties to submit evidence on economic impacts but states that the key to a convincing evidentiary demonstration is a party's ability to identify a nexus between the evidence and the specific problems at issue in the rate case. As the judges noted (R.D., pp. 9-10), no solid information was offered in these cases about customers' collective ability to pay higher rates for electric delivery service.
- d. It would be an error to ignore projected commodity cost declines when setting delivery rates.
- e. The economic challenges faced by customers should not be ignored. However, it should be noted that electric bills for the vast majority of the Company's residential customers, due to efficient usage, are low in comparison with the rest of the country and that the total average annual rate projected to be in effect at the start of the Rate Year would be approximately 7% less than in 1987 adjusted for inflation (no analysis is provided in support of either of these contentions).
- f. It is in the long term interest of the service territory that due regard be given to maintaining a

⁵⁸¹ The Company's BoE, pp. 65-67.

⁵⁸² Id., citing Case 27094, Orange and Rockland Utilities, Inc. - Order Denying Petition for Rate Investigation (issued October 3, 1978), p. 2 and Case 27361, NYSEG - Rates, Opinion No. 79-11 (issued April 20, 1979), p. 4.

financially strong utility, i.e., one that recovers all reasonable costs of electric delivery service.

DPS Staff opposes the Company's exception, contending:⁵⁸³

- a. It is imperative that a macro adjustment be considered after balancing the long- and short-term impacts on customers and shareholders; this should not be done on an issue-by-issue basis.
- b. The Company seeks a 17% delivery service revenue increase in the context of a severe national recession.⁵⁸⁴
- c. The Company is attempting to shift its business risk from shareholders to ratepayers through numerous reconciliation terms. To the extent these terms are adopted, they should be considered when determining the Company's rate of return.
- d. While competitive firms are downsizing, the Company is seeking to increase its workforce and to charge customers more. If the Company's management is unwilling to trim its capital and expense budgets, we should put the Company on an austerity budget that eliminates anything that is discretionary.
- e. The Company is incorrect to contend that delivery rates can be increased on account of anticipated commodity cost reductions. Commodity costs can be extremely volatile and should not be relied upon as a basis for setting delivery service rates.

In its brief opposing exceptions, the County adds that the Statement of Policy Concerning Evidence of Economic Impacts in Rate Cases states that it may make sense to moderate a rate increase at a time of economic distress, when higher rates would adversely affect the public by precipitating or aggravating economic dislocations and problems such as unemployment, dependence on public assistance, and the departure of industries.⁵⁸⁵

⁵⁸³ DPS Staff's B0E, pp. 37-39.

⁵⁸⁴ Others agree. See NYC Government Customers' BoE, p. 4.

⁵⁸⁵ Westchester's B0E, p. 2.

The NYC Government Customers do not except. However, they urge that we adopt adjustments offered by parties that would reduce the Company's revenue requirement without jeopardizing the Company's ability to provide safe and adequate service.⁵⁸⁶

The Company criticizes this last argument because it ignores that approximately 50% of the judges' \$632.5 million cost of service recommendation is necessary to cover New York City property tax increases.⁵⁸⁷

In the context of addressing the \$100 million reduction in the Company's 2009 capital budget that is not reflected in the judges' cost of service calculations, DPS Staff characterizes as ironic the judges' reluctance to consider in any substantive manner the 8-15% reductions proposed by the NYC Government Customers and Westchester. If we are not willing to reflect as an update the Company's \$100 million reduction in planned 2009 capital spending, DPS Staff continues, we should consider those other adjustments.⁵⁸⁸ This would be reasonable, DPS Staff says, because of current economic conditions and as the Company acknowledges that 8% of its budget is "discretionary." Given that austerity budgets are already in place for most businesses, DPS Staff asks why the Company should be any different.

In a related argument, DPS Staff denies that the Company's revenue request is ameliorated by \$426 million. According to DPS Staff, all but one of the Company's amelioration proposals amount to the Company agreeing to

⁵⁸⁶ NYC Government Customers' BoE, p. 4.

⁵⁸⁷ The Company's BOE, p. 80. The percentage is overstated somewhat.

⁵⁸⁸ The referenced \$100 million reduction in a Company forecast is discussed separately above.

continue to adhere to terms of the 2008 Rate Order that are already reflected in the Company's rates.⁵⁸⁹

The Company opposes these arguments noting that:⁵⁹⁰

- a. DPS Staff's support for across-the-board reductions in capital spending is raised for the first time in its brief on exceptions.
- b. The Company's objections to across-the-board cuts in spending are discussed above in its own exception.
- c. The record clearly establishes that the Company's projected T&D investment is mitigated.⁵⁹¹
- d. The proposed across-the-board reductions in capital expenditures will pose risks to reliability.
- e. It is not correct to state that 8% of the Company's T&D budget is discretionary as to whether or not the work needs to be done. The record shows that 75-80% of the capital budget provides capacity and conductivity to customers, meets growing load and government mandates, and addresses equipment replacement specifications. The other 20-25% is used to address reliability and is discretionary only in the sense that the Company gets to decide which reliability needs are paramount.

Responding more broadly, the Company contends that:⁵⁹²

- f. No party proposing a macro adjustment or favoring an austerity budget cites any legal basis for adopting either.
- g. With two exceptions, DPS Staff provides no clear indication of what costs it reasonably believes should be cut under its austerity budget proposal. The two exceptions concern the Company's proposed

⁵⁸⁹ See, generally, DPS Staff's BoE, pp. 53-54.

⁵⁹⁰ The Company's BOE, pp. 59-62.

⁵⁹¹ It notes, for example, its demand reduction efforts, project deferrals, productivity and process changes, system efficiencies, and the use of competitive bidding that are collectively intended to minimize T&D investment. The demand reduction initiative alone allows the Company to defer from two to seventeen years numerous capital projects totalling \$1.2 billion. Another \$155 million of capital work was also deferred.

⁵⁹² The Company's BOE, pp. 80-83.

Regulatory Affairs Department and the Emergency Child and Elder Care program. As to these, the Company says, DPS Staff opposed recovery but not on the grounds that they are discretionary. The record shows both programs are reasonable.

- h. The record includes much testimony to the effect that the Company is pursuing a mission of providing reliable service at the lowest reasonable cost.
- i. The Company's delivery system plays a critical role in the ongoing success of its service area and resources appropriate for maintenance of system integrity are of vital importance.
- j. A macro adjustment is not in order because it would be contrary to the short- and long-term interests of customers and undermine the Company's ability to maintain investor confidence and access to financial markets.

2. NYPA's Cost-Effectiveness Proposal

NYPA excepts to the extent the judges did not recommend that the company be required to prioritize its capital investments in an economic fashion.⁵⁹³ NYPA points to testimony by its witnesses to the effect that the Company has an incentive to "gold-plate" its rate base, that the Company is already the most reliable distribution company in the country, and that it is likely that some of the Company's investments go beyond the optimum level of spending. It notes as well that there is testimony by Company witnesses that the Company had never studied whether it had reached an optimum point of spending. Given this record, NYPA chastises the judges for focusing too much on whether the Company will invest up to the level it forecasts and not enough on whether the Company's investments will be cost effective.

The Company does not respond.

D. Discussion

In setting just and reasonable rates, we consider all reasonable costs that the Company will incur in order to provide

⁵⁹³ NYPA's BoE, pp. 9-10.

safe and reliable service. In setting such rates, we recognize that many of the expenses that the Company incurs are difficult to avoid or control and while the Company is challenged to achieve efficiencies and productivity gains, we generally allow some level of costs that are discretionary in nature (i.e., expenses associated with areas that are not strictly necessary for the provision of safe, adequate, and reliable service, but fund certain corporate goals and priorities that could be delayed to another day without impact). Expenditures that are reasonable during average or good economic times are not necessarily reasonable when economic conditions are extremely poor. When consumers are experiencing the extraordinary harsh economic realities we see today, a certain measure of frugality is properly expected from utilities and a reprioritizing of expenditures may be needed.

The record provides only general information about the effect of our deteriorating economic circumstances on customers' ability to pay. However, it is not seriously disputed that we are now experiencing significant weakness in the New York State economic climate.⁵⁹⁴ Indeed, the Company itself acknowledges that the economic challenges faced by customers should not be

⁵⁹⁴ According to the New York State Department of Labor, unemployment has jumped dramatically in New York City. While the city's unemployment rate averaged 5.5% last year, it has increased to over 8% in recent months. This means that the number of people in New York City seeking, but not finding, employment in both February and March of this year exceeded 330,000, an increase of over 100,000 above the 2008 average. (NYS Dept. of Labor, Local Area Unemployment Statistics Program at <http://www.labor.state.ny.us/workforceindustrydata/lslaus.shtm>). Unfortunately, the Department of Labor notes that "the evidence suggests that the national economic downturn will likely continue to negatively affect the state's labor market in the coming months." (NYS Dept. of Labor April 16, 2009 Press Release at http://www.labor.state.ny.us/pressreleases/2009/April_16_2009.htm).

ignored. Evidence of economic distress is plentiful, and distress shows up most pointedly in customers' ability to remain current on their utility bills. The Company testified to an increased level of uncollectible expenses.⁵⁹⁵ The Company's willingness to work with these customers in recent months to minimize the number of terminations is a helpful response to the immediate economic impacts that customers are facing. But more can and must be done to provide whatever relief is possible to ameliorate the adverse impacts of escalating delivery costs.

In these extraordinary times, we recognize the need for utilities to implement austerity programs to constrain costs and tighten belts to limit discretionary spending.⁵⁹⁶ We will require a meaningful further downward adjustment to the Company's revenue requirement amounting to \$60 million, half of which will be subject to further review and potential deferral based on a review of the Company's ability and best efforts to implement the required measures effectively. This amounts to approximately 3.6% of non-fuel operation and maintenance costs.

The Company's management will be responsible for determining how best to achieve the \$60 million revenue requirement reduction while maintaining reliability, service quality, and safety. To that end, the Company is directed to file a plan with the Secretary within 30 calendar days of this order's issuance to achieve at least \$60 million of annual

⁵⁹⁵ Tr. 1880.

⁵⁹⁶ We note from our limited review that in New York State and elsewhere in the U. S. utilities have recently disclosed various austerity measures designed and implemented to effectuate substantial cost savings. Such actions have included, among other things, freezing management, executive or other employee salaries (Iberdrola, American Electric Power, Inc. (AEP), Wisconsin Energy Corp. (WEC), and Duke Energy (Duke)), restricting hiring (WEC, Seattle City Light (SCL)), non-essential travel (Duke, SCL), deferring discretionary projects (AEP), and reducing capital expenses (AEP, SCL) and other operating expenses (Duke, SCL).

revenue requirement savings. It is also required to report quarterly thereafter on progress achieved in meeting that level of savings.

We believe the Company could achieve a significant portion of our austerity program revenue adjustment by reducing costs in the areas such as management and executive compensation and benefits,⁵⁹⁷ research and development, and informational advertising. We fully expect the Company to use its best efforts to achieve the entire \$60 million revenue requirement reduction. If the Company does not achieve the full amount despite its best efforts, following completion of the Rate Year the Company can petition to defer that portion of cost related to the austerity revenue adjustment, up to \$30 million, that the Company fails to achieve. Following an evaluation of whether the Company used best efforts to achieve the full \$60 million of savings reflected in rates, we would make a decision as to the amount of deferral, if any, to allow. The Company should understand that it will have to carry its burden in establishing that cost cuts could not be achieved to make the full \$60 million revenue requirement reduction.

Finally, the Company should include in its next rate filing, or within not more than 30 days thereafter, testimony describing the austerity program efforts it plans to continue beyond the Rate Year.

XIII. CONCLUSION

Having carefully reviewed the evidence; the arguments of the active parties; comments by interested public officials, organizations, and members of the public; and the recommendations of the judges and Advisory Staff, we authorize the Company to increase its annual electric revenues by

⁵⁹⁷ We note that the Company forecast a 3.5% management wage increase, effective April 2009, or approximately \$7.8 million inclusive of loadings.

\$721.405 million per year, including \$198 million for the increased PSL §18-a assessment to be surcharged. This amount is a 19.7% increase over forecast electric delivery service revenues at current rates and 6.1% increase on a total bill basis assuming current rate year commodity costs.

Key factors driving the need for a revenue increase include the following, in order of magnitude:

1. Increased property taxes \$239 million
2. Increased PSL §18-a
assessment \$198 million
3. Increase in rate base
(including depreciation) \$176 million
4. Increased costs for
pensions and other post
employment benefits \$118 million
5. Increased capital costs \$95 million

All of these factors reflect the sharp economic downturn since we last considered the Company's electric rates generally and the rate base increase reflects as well the Company's continuing need to replace outdated equipment in order to ensure safe, reliable, and otherwise adequate electric service and its need to maintain access to capital on reasonable terms.

The Commission orders:

1. Consolidated Edison Company of New York, Inc. is directed to file cancellation supplements, effective on not less than one day's notice, on or before April 28, 2009, cancelling the tariff amendments and supplements listed in Appendix I to this order.

2. Consolidated Edison Company of New York, Inc. is directed to file, on not less than one day's notice, such further tariff revisions as are necessary to effectuate the

provisions adopted by this order, including a \$721.405 million annual revenue increase to take effect May 1, 2009, as detailed in Appendix II to this order. The Company shall serve copies of its filing on all active parties in these cases. Any comments on the compliance filing must be received at the Commission's offices within 14 days of service of the Company's proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

3. Consolidated Edison Company of New York, Inc. shall file, on not less than one day's notice to become effective May 1, 2009, such further tariff revisions as are necessary to continue the adjustment clause mechanism established in Case 07-E-0523 and to modify such clause to recover, in the same manner as the Company's delivery revenue requirement is recovered in base rates, a portion of the Company's revenue requirement equal to the amount set forth in the body of this order (\$254.4 million). Such language shall specify that this portion of the revenue requirement shall be subject to refund based on the Commission's audit and review of the Company's capital expenditures as described in Case 07-E-0523 (the 2005-2008 overspend investigation) and, as set forth in Case 09-M-0114, on the Commission's audit and review of the Company's 2000-2009 contract-related capital, O&M, and related expenditures resulting from the employee and contractor corruption allegations brought to light by the United States Department of Justice. Such amount shall continue to be recovered in this manner until such time as the Commission determines otherwise. The tariff amendments specified above shall not become effective on a permanent basis until approved by the Commission.

4. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the

effective date of the proposed amendments directed in Clauses 2 and 3 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

5(a). Consolidated Edison Company of New York, Inc. is authorized, under the Revenue Decoupling Mechanism (RDM), to record and recover the non-competitive delivery service revenue shortfall, including interest at the Company's allowed pre-tax rate of return, for the 25-day period April 6, 2009 through April 30, 2009. The shortfall by service class shall be calculated as the difference between forecast sales revenues the Company would have billed at new rates for the 25-day period and the same level of sales revenues at current rates. Any revenue shortfall calculation shall also include any applicable surcharges that would have been effective during the 25-day period, such as for energy efficiency programs. The non-competitive RDM deferral will be recovered over 23 months.

5(b). Consolidated Edison Company of New York, Inc. is authorized to recover the competitive delivery service revenue shortfall (revenue associated with Merchant Function, Metering and Billing, and Payment Processing charges) including interest at the Company's allowed pre-tax rate of return, for the 25-day period April 6, 2009 through April 30, 2009. Any such recovery, with the exception of uncollectible bill expense, shall be reconciled and recovered through the Company's Transition Adjustment for Competitive Services in the 12-month period immediately following the Rate Year (i.e., in the period April 1, 2010 through March 31, 2011). The uncollectible bill expense portion of any competitive delivery service revenues shall be recovered over a one-month period.

6. Consolidated Edison Company of New York, Inc. is directed to file with the Secretary, within 30 days of this order's issuance and in accordance with the body of this order, its updated assessment surcharge for use in the orderly processing of assessment amounts to be billed to the Company.

7. Consolidated Edison Company of New York, Inc. is directed to provide in its next rate case filing, or otherwise in its next rate case in accordance with the body of this order, specified information concerning property taxes, multi-year rate plans, the depreciation reserve deficiency, and austerity plans for beyond the Rate Year ending March 31, 2010.

8. Consolidated Edison Company of New York, Inc. is directed to file with the Secretary, and serve on all existing active parties, within 30 days of this order's issuance, its plan to achieve the austerity cuts called for by this order. Following that submission, Consolidated Edison Company of New York, Inc. is directed to file with the Secretary and serve on all existing active parties, on or about every 90 days, reports concerning the Company's progress in achieving all the called for austerity cuts.

9. The revenue requirement determination in these cases reflects, among other things, the ratepayers' \$357,087, or 86%, share of the net proceeds of the tax refund subject to Case 08-M-0618. The Company's petition in that case is granted to the extent it is consistent with that outcome.

10. Except as herein granted, all exceptions to the January 7, 2009 Recommended Decision are denied.

11. Except as specified herein, the January 7, 2009 Recommended Decision is adopted as part of this order.

12. The Secretary is authorized to extend filing deadlines set forth in the body of this order to the extent good cause is shown.

CASES 08-E-0539 and 08-M-0618

13. Case 08-E-0539 is continued and Case 08-M-0618 is closed.

By the Commission,

(SIGNED)

Jaclyn A. Brilling
Secretary

Case 08-E-0539 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service

Case 08-M-0618 - Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers

Maureen F. Harris, Commissioner, dissenting

I dissent. The Commission has approved a \$721.4 million increase in Consolidated Edison's revenues, of which \$437 million, 60% of the total increase, results from property tax increases and the increases mandated by the recent amendments to Section 18-a of the Public Service Law. This Commission's principal responsibility is to provide the companies it regulates with the revenues necessary to provide safe and reliable service at just and reasonable rates. Here, however, the Commission's approval of a rate increase, comprising principally \$437 million of government imposed taxes and fees, is neither just nor reasonable during a time of unprecedented economic turmoil.

Our statutory responsibility is to ensure the Company collects only the revenues needed to offset legitimate expenses. This responsibility imposes upon us a duty to determine a proper allocation of expenses between ratepayers and the Company's shareholders. In light of these extraordinary harsh economic realities facing New Yorkers, as noted in the order, it is unjust and unreasonable to pass 100 percent of these taxes and charges on to the ratepayers. While there may be a presumption that these tax and fee increases should be borne by the ratepayer, presumption does not equate to acquiescence. Further consideration should have been given to allocating a portion of the increased taxes and 18-a assessments to the Company's shareholders. Imposing some portion of the increased taxes and assessments on the Company's shareholders would provide an economic incentive for the Company to advocate vociferously against such increases.

The unprecedented difficult economic climate and magnitude of the proposed rate increase created unique and difficult circumstances. These unique times warranted a closer look at any and all presumptions of costs passed on to the ratepayer. It is my opinion that the Commission runs the risk of becoming little more than a tax collector for political entities if we do not in these unique circumstances take a closer look at these presumptions. Some will say what I suggest is not proper or appropriate. But when the ratepayer has no option other than to pay these significant taxes and assessments levied upon them, that have nothing to do with the provision of safe and reliable service, and the utilities have no incentive to oppose these taxes since the Commission merely flows these costs on to the ratepayer, it is my obligation to object. I take little comfort that those ratepayer interests are adequately protected by the democratic process. Accordingly, and in order to draw attention to this issue, I choose to exercise my prerogative to respectfully dissent.

Filing by: CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Amendments to Schedule P.S.C. No. 9 – Electricity

First Revised Leaf No. 168-E
Ninth Revised Leaf No. 296-A
Eleventh Revised Leaves Nos. 137, 163-A
Fifteenth Revised Leaves Nos. 100, 251-A
Sixteenth Revised Leaf No. 89
Seventeenth Revised Leaves Nos. 202-A, 212-A, 240-A-1
Eighteenth Revised Leaf No. 311-A-2
Twenty-Seventh Revised Leaves Nos. 96, 230, 232, 233,
240, 262, 264, 265, 272, 274, 275, 311, 313, 322
Twenty-Eighth Revised Leaves Nos. 245, 314
Twenty-Ninth Revised Leaves Nos. 202, 315
Thirtieth Revised Leaves Nos. 212, 251

Amendments to Schedule P.S.C. No. 2 – Retail Access

Sixth Revised Leaves Nos. 181, 182
Eighth Revised Leaf No. 177
Ninth Revised Leaves Nos. 146, 147, 148, 149, 150, 151,
152, 153, 154, 155, 178
Tenth Revised Leaf No. 156

Amendments to PASNY No. 4

Fourth Revised Leaf No. 10-C
Seventh Revised Leaves Nos. 6-A, 6-C, 6-E, 6-F
Tenth Revised Leaf No. 4
Fourteenth Revised Leaf No. 5
Fifteenth Revised Leaf No. 3

Amendments to Economic Development Delivery Service No. 2

Twelfth Revised Leaves No. 4, 5

Consolidated Edison Company of New York, Inc.
Electric Operating Income, Rate Base & Rate of Return
For the Rate Year Ending March 31, 2010
(\$000's)

	<u>Per Recommended Decision</u>	<u>Adj. No.</u>	<u>Commission Adjustments</u>	<u>As Adjusted by Commission</u>	<u>Revenue Requirement Adjustment</u>	<u>As Adjusted For Revenue Requirement</u>
<u>Operating Revenues</u>						
Sales Revenues	\$7,285,444	1	(\$12,775)	\$7,272,669	\$523,405	\$7,796,074
Unbilled Revenues	14,000		0	14,000	0	14,000
Other Operating Revenues	265,220	2	(7,398)	257,822	1,832	259,654
Total Operating Revenues	7,564,664		(20,173)	7,544,491	525,237	8,069,728
<u>Operating Expense</u>						
Fuel	3,147,757		0	3,147,757	0	3,147,757
Operation & Maintenance Expenses	1,670,819	3	(35,863)	1,634,956	3,507	1,638,463
Depreciation Expense	591,346	4	(5,519)	585,827	0	585,827
Taxes Other Than Income Taxes	1,289,862	5	(39,770)	1,250,092	13,661	1,263,753
Gains from Disposition of Utility Plant	0			0		0
Total Operating Expenses	6,699,784		(81,151)	6,618,633	17,168	6,635,800
Operating Income Before Income Taxes	864,880		60,978	925,858	508,069	1,433,928
New York State Income Tax	26,851	6	5,736	32,587	36,073	68,660
Federal Income Tax	76,198	7	25,457	101,655	165,199	266,854
Net Utility Operating Income	\$761,831		\$29,785	\$791,616	\$306,798	\$1,098,414
Rate Base	\$14,404,702	8	(\$307,379)	\$14,097,323		\$14,097,323
Rate of Return	5.29%			5.62%		7.79%

Consolidated Edison Company of New York, Inc.
Other Operating Revenues
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj. No. 2	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Miscellaneous Service Revenues	\$13,174			\$13,174		\$13,174
Rent from Electric Property	15,601			15,601		15,601
Interdepartmental Rents	11,063			11,063		11,063
Other Electric Revenues:						
Transmission of Energy	11,456			11,456		11,456
Transmission Service Charges	18,600			18,600		18,600
Maintenance of Interconnection Facilities	2,183			2,183		2,183
Excess Distribution Facilities	2,559			2,559		2,559
Late Payment Charges	25,561	a	(\$45)	25,516	\$1,832	27,348
Meter Reading Services	2,821			2,821		2,821
The Learning Center Services	769			769		769
Fuel Management	134			134		134
Transmission Congestion Credits	120,000			120,000		120,000
Sithe Agreement	2,263			2,263		2,263
Purchase of Receivable Discount	7,710			7,710		7,710
ESCOs / Marketer Charges	4,608			4,608		4,608
SO2 Allowance	3,300			3,300		3,300
Intercompany Rents 74/59th Street	(6,500)			(6,500)		(6,500)
Low Income Discount Program	(19,224)	b	(3,645)	(22,869)		(22,869)
Regulatory Deferrals:						
NYS Tax Law Changes	8,465			8,465		8,465
DC Service Incentive	3,000			3,000		3,000
S02 Credits	3,300			3,300		3,300
Verizon Pole Maintenance Contract	14,500			14,500		14,500
ADR Tax Amortization	16,357			16,357		16,357
Interest on FIT Audit Adjustments - Net	7,404			7,404		7,404
Gain on Sale of First Avenue Properties	43,890			43,890		43,890
Interest on Sale of First Avenue Properties	2,752			2,752		2,752
WTC Expenses	(14,000)			(14,000)		(14,000)
Carrying Charges on T&D Expenditures	(19,498)			(19,498)		(19,498)
Excess Deferred SIT	5,105			5,105		5,105
Transmission Service Charges	2,591	c	4,657	7,248		7,248
Deferred Property Tax Refund	258			258		258
Return of Stony Point Tax Refund	1,400			1,400		1,400
Misc. Property Tax Refunds	3,629			3,629		3,629
Deferrals from Case 04-E-0572 RY3	(5,592)			(5,592)		(5,592)
Interest on Deferrals from C. 04-E-0572 RY3	(186)			(186)		(186)
Pension / OPEB Deferral	(6,428)	d	(8,365)	(14,793)		(14,793)
SIR Deferral	(17,218)			(17,218)		(17,218)
Property Tax Deferral	0			0		0
DSM	(587)			(587)		(587)
Total Other Operating Revenues	\$265,220		(\$7,398)	\$257,822	\$1,832	\$259,654

Consolidated Edison Company of New York, Inc.
Operation & Maintenance Expenses
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	No. 3	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Admin & General Expenses Capitalized	(\$36,621)	a	\$3,970	(\$32,651)		(\$32,651)
Inter-Utility Agreement - Ramapo-O&R	516			516		516
Asbestos Removal	239			239		239
Bank Collection Fees	266			266		266
Betterment Program	1,930			1,930		1,930
Boiler Cleaning	499			499		499
Building Services / Facilities	21,988			21,988		21,988
Central Engineering - Administrative	25			25		25
Central Engineering - Distribution	837			837		837
Collection Agency Fees	2,057			2,057		2,057
Communications - Telephone	12,620			12,620		12,620
Company Labor	550,946	b	(15,018)	535,928		535,928
AMR / AMI Saturation Savings	(778)			(778)		(778)
Consultants	11,620	c	(1,192)	10,428		10,428
Contract Labor	19,112	d	(7,300)	11,812		11,812
Corrective Maintenance	4,029			4,029		4,029
Contract Change	(3,080)			(3,080)		(3,080)
Disposal of Obsolete M&S	6,072			6,072		6,072
DSM	26,331			26,331		26,331
Duplicate Misc. Charges	(23,455)			(23,455)		(23,455)
EDP Equipment Rentals & Maintenance	4,184			4,184		4,184
Electric and Gas Used	731			731		731
Employee Pension / OPEBs	145,228	e	50,910	196,138		196,138
Employee Welfare Expense - Net	101,775	f	(836)	100,939		100,939
Environmental Expenses	17,283	g	(573)	16,710		16,710
ERRP - Major Maintenance	7,292			7,292		7,292
Facilities Maintenance	4,048			4,048		4,048
Financial Services	7,024			7,024		7,024
Gas Turbines	3,039			3,039		3,039
Information Resources	23,802			23,802		23,802
Informational Advertising	12,931	h	(6,669)	6,262		6,262
Injuries and Damages Reserve	41,073			41,073		41,073
Institutional Dues & Subscriptions	1,718	i	(57)	1,661		1,661
Insurance Premiums	21,153	j	(1,497)	19,656		19,656
Interference	88,854	k	(17,036)	71,818		71,818
Corporate and Fiscal Expenses	3,638			3,638		3,638
Mobile Diesel Generators	6,523			6,523		6,523
Manhour Expense	48,629			48,629		48,629
Marshall's Fees	1,099			1,099		1,099
Materials and Supplies	27,441	l	1,438	28,879		28,879
Other Compensation	0			0		0
Outreach & Education	5,338	m	(730)	4,608		4,608
Other (Fossil)	1,797			1,797		1,797
Outside Legal Services	1,696			1,696		1,696
Paving	1,928			1,928		1,928
Plant Component Upgrade	428			428		428
Postage	14,079			14,079		14,079
Preventive Maintenance	1,665			1,665		1,665
RCA - Amortization of Hudson-Farragut	477			477		477
Real Estate Expenses	1,037			1,037		1,037
Regulatory Commission Expenses	28,051	n	2,000	30,051		30,051
Rents	63,571	o	(6,828)	56,743		56,743
Rents (ERRP)	68,547			68,547		68,547
Rents (Interdepartmental)	5,450			5,450		5,450
Research and Development	18,660	p	35	18,695		18,695
SBC / RPS	126,421	q	24,169	150,590		150,590
Stray Voltage	23,414	r	(1,400)	22,014		22,014
Scheduled Overhauls	2,690			2,690		2,690
Security	2,664			2,664		2,664
Shared Services	(8,924)			(8,924)		(8,924)
Storm Costs	5,600			5,600		5,600
Transformer Installations	96			96		96
Tree Trimming	16,551			16,551		16,551
Trenching	9,475	s	(264)	9,211		9,211
Uncollectible	51,080	t	2,035	53,115	3,507	56,622
Water	714			714		714
Water Chemicals	154			154		154
Other O&M	65,542	u	(61,020)	4,522		4,522
Total O & M Expenses	\$1,670,819		(\$35,863)	\$1,634,956	\$3,507	\$1,638,463

Consolidated Edison Company of New York, Inc.
Other Electric O & M
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj No. 3. u	Commission Adjustments	As Adjusted by Commission	Requirement Adjustment	As Adjusted For Revenue Requirement
Electric Parts, Repairs & Service	\$11,157			\$11,157		\$11,157
Other Equipment, Parts, Repair & Service	3,147			3,147		3,147
Misc. Materials, Hardware, Parts & Supplies	5,952			5,952		5,952
Vehicle Maint., Service & Other Transportation	2,385			2,385		2,385
Substation Equipment, Parts, & Services	5,285			5,285		5,285
Training & Development	1,933			1,933		1,933
Audio & Visual	379			379		379
Printing Services	680			680		680
Programming Services	2,612			2,612		2,612
Rental Equipment - Other	2,082			2,082		2,082
Testing & Inspection	16,535			16,535		16,535
Other	13,395	3.u 1-6	(61,020)	(47,625)		(47,625)
Total Other Electric O & M	\$65,542		(\$61,020)	\$4,522	\$0	\$4,522

Consolidated Edison Company of New York, Inc.
Taxes Other Than Income Taxes
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj. No. 5	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
<u>Property Taxes</u>						
New York City	\$931,136	a	(\$37,331)	\$893,805		\$893,805
Upstate & Westchester	90,225	b	(550)	89,675		89,675
Total Property Taxes	<u>1,021,361</u>		<u>(37,881)</u>	<u>983,480</u>	<u>0</u>	<u>983,480</u>
Revenue Taxes	198,044	c	(527)	197,517	13,661	211,178
Payroll Taxes	47,980	d	(1,362)	46,618		46,618
Subsidiary Capital Tax	5,229			5,229		5,229
Receipts Tax	14,622			14,622		14,622
All Other Taxes	2,626			2,626		2,626
Total Taxes Other Than Income Taxes	<u>\$1,289,862</u>		<u>(\$39,770)</u>	<u>\$1,250,092</u>	<u>\$13,661</u>	<u>\$1,263,753</u>

Consolidated Edison Company of New York, Inc.
New York State Income Tax
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj. No. 6	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Income Before Income Taxes	\$864,880		\$60,978	\$925,858	\$508,069	\$1,433,928
Flow Through Items:						
<u>Non-Taxable Income and Additional Deductions:</u>						
Interest Expense	450,479		(19,809)	430,670		430,670
Medicare Part D Subsidy	15,347			15,347		15,347
Total Deductions	465,826		(19,809)	446,017	0	446,017
Normalized Items:						
<u>Additional Income and Unallowable Deductions</u>						
Book Depreciation	591,346		(5,519)	585,827		585,827
Contributions in Aid of Construction	672			672		672
Capitalized Interest	17,662			17,662		17,662
Pension and OPEB Expenses Per Books	182,212		28,719	210,931		210,931
Total Additions	791,892		23,200	815,092	0	815,092
<u>Non-Taxable Income and Additional Deductions</u>						
NYS Depreciation	536,354		(5,006)	531,348		531,348
263A Capitalized Overheads	62,023			62,023		62,023
Removal Costs	201,879			201,879		201,879
Repair Allowance	47,326			47,326		47,326
Amortization of Capitalized Interest	3,929			3,929		3,929
Loss on MACRS Retirement	44,986			44,986		44,986
Pension / OPEB Expense - Funding	189,037		95,700	284,737		284,737
Westchester Property Tax Adjustment	1,416			1,416		1,416
Credits from Case 07-E-0523	87,231			87,231		87,231
Stony Point Property Tax Refund	5,029			5,029		5,029
SO2 Credits	3,300			3,300		3,300
Management Audit	0			0		0
WTC Expenses	(14,000)			(14,000)		(14,000)
Deferrals from Case 04-E-0572 RY3	(5,592)			(5,592)		(5,592)
Interest on Deferrals from Case 04-E-0572 RY3	(186)			(186)		(186)
T&D Deferral from Case 07-E-0523	(19,498)			(19,498)		(19,498)
SIR Deferral - April 2008-March 2010	(17,218)			(17,218)		(17,218)
Property Tax Increase Deferral - April 08-March 09	0			0		0
Property Tax Deferral for earlier end to tax rebate	0			0		0
DSM	(587)			(587)		(587)
TSC Revenues	2,591		4,657	7,248		7,248
Total Deductions	1,128,020		95,351	1,223,371	0	1,223,371
Total Adjustments to Income	(801,954)		(52,342)	(854,296)	0	(854,296)
NYS Taxable Income	62,926		8,636	71,562	508,069	579,632
Current NYS Income Tax Payable @ 7.1%	4,468		613	5,081	36,073	41,154
Deferred NYS Income Tax @ 7.1%	23,865		5,123	28,988	0	28,988
Brownfield Credit	(1,482)			(1,482)		(1,482)
Total New York State Income Tax	\$26,851		\$5,736	\$32,587	\$36,073	\$68,659

Consolidated Edison Company of New York, Inc.
Federal Income Tax
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj. No. 7	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Income Before Income Taxes	\$864,880		\$60,978	\$925,858	\$508,069	\$1,433,928
New York State Income Tax	26,851		5,736	32,587	36,073	68,659
Operating Income Before Federal Income Tax	838,029		55,242	893,272	471,996	1,365,269
Flow Through Items:						
Add: Additional Income and Unallowable Deductions						
Book Depreciation	591,346		(5,519)	585,827		585,827
Hudson-Farragut Amortization - Per Books	477			477		477
Capitalized Interest	17,662			17,662		17,662
Total Additions	609,485		(5,519)	603,966	0	603,966
Deduct: Non-Taxable Income and Additional Deductions						
Interest Expense	450,479		(19,809)	430,670		430,670
Statutory Depreciation - at Current Book Rates	343,049		(3,202)	339,847		339,847
Statutory Depreciation - Change at Proposed Book Rates	0			0		0
Statutory Depreciation - Change with Reserve Deficiency	0			0		0
Removal Costs	201,879			201,879		201,879
Medicare Part D Subsidy - Post-Employment Benefits	15,347			15,347		15,347
Amortization of Capitalized Interest	2,073			2,073		2,073
Westchester Property Tax Adjustment	1,416			1,416		1,416
Dividends Paid on \$5 Cumulative Preferred Stock	3,327			3,327		3,327
Total Deductions	1,017,570		(23,011)	994,559	0	994,559
Normalized Items:						
Add: Additional Income and Unallowable Deductions						
Contributions in Aid of Construction	672			672		672
Pension / OPEB Expenses - Rate Year	182,212		28,719	210,931		210,931
Deferred NYS Income Tax	23,865		5,123	28,988		28,988
Total Additions	206,749		33,842	240,591	0	240,591
Deduct: Non-Taxable Income and Additional Deductions						
Statutory Depreciation - at Current Book Rates	248,795		(2,322)	246,473		246,473
Statutory Depreciation - Change at Proposed Book Rates	0			0		0
Statutory Depreciation - Change with Reserve Deficiency	0			0		0
263A Capitalized Overheads	62,023			62,023		62,023
Repair Allowance	47,326			47,326		47,326
Amortization of Capitalized Interest	1,856			1,856		1,856
Loss on MACRS Retirement	40,173			40,173		40,173
Pension / OPEB Expense - Funding	189,037		95,700	284,737		284,737
Correction of ADR Tax Amortization	0			0		0
Interest on Federal Income Tax Audit Adjustments - Net	0			0		0
Credits from Case 07-E-0523	87,231			87,231		87,231
Stony Point Property Tax Refund	5,029			5,029		5,029
SO2 Credits	3,300			3,300		3,300
Management Audit	0			0		0
WTC Expenses	(14,000)			(14,000)		(14,000)
Deferrals from Case 04-E-0572 RY3	(5,592)			(5,592)		(5,592)
Interest on Deferrals from Case 04-E-0572 RY3	(186)			(186)		(186)
T&D Deferral from Case 07-E-0523	(19,498)			(19,498)		(19,498)
SIR Deferral - April 2008-March 2010	(17,218)			(17,218)		(17,218)
Property Tax Increase Deferral - April 2008-March 2010	0			0		0
Property Tax Deferral for earlier end to tax rebate	0			0		0
DSM	(587)			(587)		(587)
TSC Revenues	2,591		4,657	7,248		7,248
Total Deductions	630,280		98,035	728,315	0	728,315
Total Adjustments to Income	(831,615)		(46,701)	(878,317)	0	(878,317)
Federal Taxable Income	6,414		8,541	14,955	471,996	486,952
Current Federal Income Tax @ 35%	2,245		2,989	5,234	165,199	170,433
Deferred Federal Income Tax @ 35%	148,236		22,468	170,703	0	170,703
Amortization of Previously Deferred Federal Income Tax						
Depreciation - ADR/ACRS/MACRS - at Current Book Rates	(45,055)			(45,055)		(45,055)
Depreciation - ADR/ACRS/MACRS - at Proposed Book Rates	0			0		0
Depreciation - ADR/ACRS/MACRS - Reserve Deficiency	0			0		0
Loss on MACRS Retirements	(5,558)			(5,558)		(5,558)
Repair Allowance	(9,844)			(9,844)		(9,844)
Capitalized Overheads	(10,296)			(10,296)		(10,296)
Depreciation on Capitalized Maintenance/Computer Software	1,223			1,223		1,223
Investment Tax Credit	(4,752)			(4,752)		(4,752)
Total Federal Income Tax	\$76,198		\$25,457	\$101,655	\$165,199	\$266,855

Consolidated Edison Company of New York, Inc.
Rate Base
For the Rate Year Ending March 31, 2010
(\$000's)

	Per Recommended Decision	Adj. No. 8	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Utility Plant:						
Book Cost of Plant	\$18,747,766	a	(\$106,678)	\$18,641,088		\$18,641,088
Accumulated Reserve for Depreciation	(3,805,654)	b	2,050	(3,803,604)		(3,803,604)
Net Plant	14,942,112		(104,628)	14,837,484		14,837,484
Non-Interest Bearing CWIP	558,093			558,093		558,093
Preferred Stock Expense	2,414			2,414		2,414
Unamortized Debt Discount Premium and Expense	137,066			137,066		137,066
Deferred Fuel - Net of Tax	32,500			32,500		32,500
Unamortized Balance - Hudson Farragut	1,323			1,323		1,323
Customer Advances for Construction	(269)			(269)		(269)
MTA Surtax - Net of Tax	3,063			3,063		3,063
Working Capital	595,536	c	(22,970)	572,566		572,566
Excess Rate Base Over Capitalization Adjustment	191,387			191,387		191,387
Early Retirement Termination Benefit (1999) - Net of Tax	7,795			7,795		7,795
DC Service Incentive - Net of Tax	(2,907)			(2,907)		(2,907)
System Benefits Charge/Retail Portfolio Standard - Net of Tax	4,011			4,011		4,011
Amounts Billed in Advance of Construction - Net of Tax	(5,709)			(5,709)		(5,709)
BIR Discounts - Recovery - Net of Tax	0			0		0
ERRP Major Maintenance	(1,325)			(1,325)		(1,325)
Rate Case Reconciliations - Net of Federal Income Taxes						
Recovery of Deferrals from C 04-E-0572 RY3	8,721			8,721		8,721
Recovery of Various Deferrals from C. 07-E-0523	100,079			100,079		100,079
Recovery of Pension Deferrals from C. 07-E-0523	0			0		0
Recovery of SIR Deferrals from C. 07-E-0523	98,772			98,772		98,772
Recovery of 2008/2009 Property Tax Increase	0			0		0
Refund of Credit from C. 07-E-0523	(79,012)			(79,012)		(79,012)
Refund of Stony Point Property Tax Refund	(1,518)			(1,518)		(1,518)
Refund of SO2 Credits	(996)			(996)		(996)
Unbilled Revenues	54,950			54,950		54,950
Verizon Pole Maintenance - Reimbursement	(4,378)			(4,378)		(4,378)
Deferred TSC Revenues	(3,911)	d.1	(7,030)	(10,941)		(10,941)
Deferred DSM Costs	886			886		886
Deferred Scheduled Overhaul Costs	1,258	d.2	(1,258)	0		0
Deferred Facilities Maintenance Costs	743	d.3	(743)	0		0
Accumulated Deferred Income Taxes						
ADR / ACRS / MACRS Deductions	(1,743,400)	e.1	(165,627)	(1,909,027)		(1,909,027)
Change of Accounting Section 263A	(316,186)			(316,186)		(316,186)
Vested Vacation	11,529			11,529		11,529
Prepaid Insurance Expenses	(3,817)			(3,817)		(3,817)
Unbilled Revenues	110,440			110,440		110,440
Contributions in Aid of Construction	12,295			12,295		12,295
Capitalized Interest	4,592			4,592		4,592
Repair & Maintenance Allowance - 2002-2006 IRS Audit	4,507			4,507		4,507
Fin 48 - Disallowed SSCM	(57,475)			(57,475)		(57,475)
MTA	(12,359)			(12,359)		(12,359)
Amortization of Computer Software	(43,047)			(43,047)		(43,047)
Customer Deposits	20,278			20,278		20,278
Call Premium	(19,552)			(19,552)		(19,552)
Deferred SIT	(203,787)	e.2	(5,123)	(208,910)		(208,910)
Total Rate Base	\$14,404,702		(\$307,379)	\$14,097,323	\$0	\$14,097,323

Consolidated Edison Company of New York, Inc.
Working Capital Allowance
For the Rate Year Ending March 31, 2010
(\$000's)

	<u>Per Recommended Decision</u>	<u>Adj. No. 8</u>	<u>Commission Adjustments</u>	<u>As Adjusted by Commission</u>
<u>Materials & Supplies</u>				
Liquid Fuel Inventory	\$7,259			\$7,259
Materials & Supplies, Excluding Fuel	88,670			88,670
Total Materials & Supplies	<u>95,929</u>		<u></u>	<u>95,929</u>
<u>Prepayments</u>				
Insurance	10,240	c.1	(\$1,395)	8,845
Rents	15,519			15,519
Property Taxes	221,031	c.2	(10,474)	210,557
PSC Assessment	7,792			7,792
Interference	3,756			3,756
EPRI	264			264
Other	11,222			11,222
Total Prepayments	<u>269,824</u>		<u>(11,869)</u>	<u>257,955</u>
<u>Cash Working Capital</u>				
Total Operations & Maintenance Expenses	4,818,576	Sch 3	(35,863)	4,782,713
Less:				
Purchased Power Expenses	2,838,515			2,838,515
Gas Portion of Fuel	304,853			304,853
Recoverable Fuel Costs	22,799			22,799
Interdepartmental Rents	5,450			5,450
Uncollectible Accounts	51,080	3. t	2,035	53,115
Pensions / OPEBs	145,228	3.e	50,910	196,138
Subtotal	<u>3,367,925</u>		<u>52,945</u>	<u>3,420,870</u>
Cash Working Capital Subject to 1/8th Allowance	<u>1,450,651</u>		<u>(88,808)</u>	<u>1,361,843</u>
Cash Working Capital @ 1/8th	181,331	c.3	(11,101)	170,230
Add: Cash Working Capital @ 1/12th on Recoverable Fuel Costs	<u>1,900</u>		<u>0</u>	<u>1,900</u>
Total Cash Working Capital	183,231		(11,101)	172,130
Sub-total Working Capital	<u>548,984</u>		<u>(22,970)</u>	<u>526,014</u>
Add: Working Capital Related to Purchased Power @ 1.64%	<u>46,552</u>		<u>0</u>	<u>46,552</u>
Total Working Capital Allowance	<u>\$595,536</u>		<u>(\$22,970)</u>	<u>\$572,566</u>

Consolidated Edison Company of New York, Inc.
Explanation of Commission Adjustments
For the Rate Year Ending March 31, 2010
(\$000's)

Adj.		Amount
No.	Explanation	
1	<u>Sales Revenues</u>	
	a. To properly reflect the impact of the Company's update of rate year sales revenues.	(\$12,700)
	b. To reflect the impact of the Company's sales update on rate year BPP/MFC/Metering revenues.	(75)
	Total Adjustments to Sales Revenues	<u>(\$12,775)</u>
2	<u>Other Operating Revenues</u>	
	a. <u>Late Payment Charges</u>	
	Tracking the Commission's adjustments to sales revenues.	(\$45)
	b. <u>Low Income Discount Program</u>	
	To reflect the Commission's increased funding for the low income discount program.	(3,645)
	c. <u>Deferred Transmission Service Charges (TSC) Revenues</u>	
	To reflect the increase in the refunding of deferred TSC revenues in the rate year.	4,657
	d. <u>Pension / OPEB Deferral</u>	
	To reflect the increase in the recovery of deferred pension / OPEB expense in the rate year.	(8,365)
	Total Adjustments to Other Operating Revenues	<u>(\$7,398)</u>
3	<u>Operation & Maintenance Expenses (O&M):</u>	
	a. <u>Administrative & General Expenses - Capitalized</u>	
	To update the A&G transfer credit for the Commission's rate year forecast of capital expenditures.	\$3,970
	b. <u>Company Labor</u>	
	1. To reflect the Commission's adjustments to program change requests.	(\$5,631)
	2. To reflect the Commission's adjustment to the rate year labor escalation rate.	<u>(9,387)</u>
	Total Adjustments to Company Labor	(15,018)
	c. <u>Consultants</u>	
	1. To reflect the Commission's adjustment to energy efficiency program related costs.	(1,075)
	2. To reflect the Commission's adjustment for incremental emergency management costs.	<u>(117)</u>
	Total Adjustments to Consultants	(1,192)
	d. <u>Contract Labor</u>	
	To reflect the Commission's adjustments to the 5-year underground inspection program.	(7,300)
	e. <u>Employee Pension / OPEBs</u>	
	To reflect the Company's latest forecast of rate year pension and OPEB costs.	50,910
	f. <u>Employee Welfare</u>	
	To reflect the Commission's rate year forecast of employee welfare expense.	(836)
	g. <u>Environmental Expenses</u>	
	To reflect the Commission's historic hiring practices adjustment.	(573)
	h. <u>Informational Advertising</u>	
	To reflect the Commission's rate year forecast of informational advertising.	(6,669)

Consolidated Edison Company of New York, Inc.
Explanation of Commission Adjustments
For the Rate Year Ending March 31, 2010
(\$000's)

Adj. No.	<u>Explanation</u>	<u>Amount</u>
3	i. <u>Institutional Dues & Subscriptions</u> To reflect the Commission's adjustment to energy efficiency program related costs. j. <u>Insurance Premiums</u> 1. To reflect the Commission's forecast of rate year D&O insurance. (\$802) 2. To reflect the Commission's forecast of rate year insurance based on the GDP. (695) Total Adjustments to Insurance Premiums (1,497) k. <u>Interference</u> To reflect the Commission's rate year forecast of municipal infrastructure support expense. (17,036) l. <u>Materials & Supplies</u> 1. To reflect the Commission's adjustment to the 5-year underground inspection program. 1,500 2. To reflect the Commission's adjustment for incremental emergency management costs. (8) 3. To reflect the Commission's historic hiring practices adjustment. (62) Total Adjustments to Materials & Supplies 1,438 m. <u>Outreach & Education</u> To reflect the Commission's rate allowance for Outreach & Education costs. (730) n. <u>Regulatory Commission Expenses</u> To reverse the rate case disallowance associated with general equipment. 2,000 o. <u>Rents</u> To remove rent associated with the relocation of the West 28th St. Service Center. (6,828) p. <u>Research & Development</u> 1. To reflect the Commission's capitalization of R&D costs. 435 2. To reflect the Commission's adjustment to energy efficiency program related costs. (400) 35 q. <u>SBC/RPS</u> To correct the Company's error in the level of SBC reimbursements. 24,169 r. <u>Stray Voltage</u> To reflect the Commission's rate year forecast of stray voltage expenditures. (1,400) s. <u>Trenching</u> To reflect the Commission's historic hiring practices adjustment. (264) t. <u>Uncollectible Accounts</u> To update the rate year forecast based on the latest 12-months write-off rate. 2,035 u. <u>Other O&M</u> 1. To reflect the Commission's historic hiring practices adjustment. (253) 2. To reflect the Commission's adjustment Structural Integrity / Station Betterment costs. (394) 3. To reflect the Commission's decision for incremental non-labor Emergency Management expenses. (330) 4. To reflect the Commission's rate year forecast of vehicle fuel expense. (654) 5. To reflect the Commission's adjustment to the Public Affairs program. (36) 6. To reflect the Commission's austerity adjustment. (60,000) Total Adjustments to Other O&M (61,020) Total Adjustments to Operating and Maintenance Expenses (\$35,863)	
4	<u>Depreciation Expense</u> To reflect the Commission's rate year forecast of depreciation expense.	(\$5,519)

Consolidated Edison Company of New York, Inc.
Explanation of Commission Adjustments
For the Rate Year Ending March 31, 2010
(\$000's)

Adj. No.	<u>Explanation</u>	<u>Amount</u>
5	<u>Taxes Other Than Income Taxes</u>	
	<u>Property Taxes</u>	
a.	<u>NYC</u>	
	To update the forecast of NYC rate year property tax expense.	(\$37,331)
b.	<u>Westchester</u>	
	To update the forecast of Westchester rate year property tax expense.	(550)
	Total Adjustments to Property Taxes	(\$37,881)
c.	<u>Revenue Taxes</u>	
	Tracking the rate year revenue adjustments.	(527)
d.	<u>Payroll Taxes</u>	
	Tracking the adjustments to rate year labor expense.	(1,362)
	Total Adjustments to Taxes Other Than Income Taxes	(\$39,770)
8	<u>Rate Base</u>	
a.	<u>Book Cost of Plant</u>	
	To reflect the Commission's adjustments and updates to plant in service.	(\$106,678)
b.	<u>Accumulated Reserve for Depreciation</u>	
	To reflect the Commission's adjustments and updates to accumulated reserve for depreciation.	2,050
c.	<u>Working Capital</u>	
1.	<u>Prepaid Insurance</u>	
	Tracking the adjustments to insurance expense.	(\$1,395)
2.	<u>Prepaid Property Tax</u>	
	Tracking the adjustments to property tax expense.	(10,474)
3.	<u>Cash Working Capital</u>	
	Tracking the adjustments to O&M expense.	(11,101)
	Total Adjustments to Working Capital	(22,970)
d.	<u>Regulatory Deferrals:</u>	
1.	<u>Deferred TSC Revenues</u>	
	To update the level of unamortized deferred TSC revenues in the rate year.	(7,030)
2.	<u>Deferred Scheduled Overhaul Costs</u>	
	To reflect the Commission's treatment for deferred overhaul costs.	(1,258)
3.	<u>Deferred Facilities Maintenance Costs</u>	
	To reflect the Commission's treatment for deferred Local Law 11 costs.	(743)
	Total Adjustments to Regulatory Deferrals	(9,031)
e.	<u>Accumulated Deferred Income Taxes</u>	
1.	<u>ADR / ACRS / MACRS Deductions</u>	
	Tracking the change to book-tax depreciation differences.	406
	To reflect deferred income taxes associated with recent tax depreciation law changes.	(166,033)
	Total ADR / ACRS / MACRS Deductions	(165,627)
2.	<u>Deferred SIT</u>	
	Tracking the Commission's SIT calculation.	(5,123)
	Total Adjustments to Accumulated Deferred Income Taxes	(170,750)
	Total Adjustments to Rate Base	(\$307,379)

WAGE PROGRESSION INCREASES EXAMPLE

The Company testified that its union employee count rose 10% over the course of more than three and a half years, or less than 3% per year. Thus, on average, for every 100 union employees that leave the Company, no more than 103 are hired.

- a. Assume conservatively that 98 of the 100 employees leaving the Company are below top of grade, and thus still eligible for wage progression increases, and that only two are at the top of grade, whether retirees or other.
- b. Assume conservatively that 98 of the new employees are hired below maximum salary level and thus eligible for progression increases. The progression increases for those 98 new employees will merely replace the progression increases for the 98 of 100 below-top-of-grade positions vacated.
- c. Assume the five remaining new employees are at entry level (bottom of grade). Those five would be eligible for a cumulative total of 10 progression increases over the course of a year (e.g., the Rate Year).
- d. Assume conservatively that it takes only three years, or six progression increases, for a union employee to move from the bottom of the pay scale to the maximum rate. Thus, a person at top of grade has a salary level six progressions higher than an employee at the bottom of grade. Then every employee at the top of grade who leaves the Company frees up an amount equivalent to six progression increases for new employees at bottom of grade eligible for progressions. The two employees leaving at top of grade will offset 12 progression increases for eligible employees at bottom of grade. The progression increases for the five new employees at bottom of grade would replace only 10 of those 12.

- e. Under this very conservative set of assumptions, the Company would save two progression increases for every 100 retirees or other employees leaving. Under any less conservative set of assumptions about the number of employees at top of grade out of every 100 leaving (i.e., >2%), number of new employees hired at entry level (i.e., >5%), or number of years to progress from bottom to top of grade (i.e., >3) the Company will save even more.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
AVERAGE COST OF LONG TERM DEBT
TWELVE MONTHS ENDING MAR. 31, 2010
(Thousands of Dollars)

Debentures			Due	Debt Outstanding 3/31/2010	Cost Rate	Average Balance 3/31/2010	Average Cost	Effective Cost Rate
1998	Series B	02/01/28	105,000	105,000	7.100%	105,000	7,455	0.077%
1998	Series D	10/01/28	75,000	75,000	6.900%	75,000	5,175	0.054%
1999	Series B	12/01/09	0	0	7.150%	133,333	9,533	0.099%
2000	Series A	05/01/10	325,000	325,000	8.125%	325,000	26,406	0.273%
2000	Series B	09/01/10	300,000	300,000	7.500%	300,000	22,500	0.233%
2002	Series A	07/01/12	300,000	300,000	5.625%	300,000	16,875	0.174%
2002	Series B	02/01/13	500,000	500,000	4.875%	500,000	24,375	0.252%
2003	Series A	04/01/33	175,000	175,000	5.875%	175,000	10,281	0.106%
2003	Series B	06/15/13	200,000	200,000	3.850%	200,000	7,700	0.080%
2003	Series C	06/15/33	200,000	200,000	5.100%	200,000	10,200	0.105%
2004	Series A	02/01/14	200,000	200,000	4.700%	200,000	9,400	0.097%
2004	Series B	02/01/34	200,000	200,000	5.700%	200,000	11,400	0.118%
2004	Series C	06/15/09	0	0	4.700%	57,292	2,693	0.028%
2005	Series A	03/01/35	350,000	350,000	5.300%	350,000	18,550	0.192%
2005	Series B	07/01/35	125,000	125,000	5.250%	125,000	6,563	0.068%
2005	Series C	12/15/15	350,000	350,000	5.375%	350,000	18,813	0.195%
2006	Series A	03/15/36	400,000	400,000	5.850%	400,000	23,400	0.242%
2006	Series B	06/15/36	400,000	400,000	6.205%	400,000	24,820	0.257%
2006	Series C	09/15/16	400,000	400,000	5.500%	400,000	22,000	0.227%
2006	Series D	12/01/16	250,000	250,000	5.300%	250,000	13,250	0.137%
2006	Series E	12/01/36	250,000	250,000	5.700%	250,000	14,250	0.147%
2007	Series A	08/15/37	525,000	525,000	6.300%	525,000	33,075	0.342%
2008	Series A	04/01/18	600,000	600,000	5.850%	600,000	35,100	0.363%
2008	Series B	04/01/38	600,000	600,000	6.750%	600,000	40,500	0.419%
2008	Series C	12/01/18	600,000	600,000	7.125%	600,000	42,750	0.442%
2009	Series A	04/01/14	275,000	275,000	5.570%	275,000	15,318	0.158%
2009	Series B	04/01/19	475,000	475,000	6.670%	475,000	31,683	0.328%
2009	Series C	12/01/39	730,000	730,000	6.970%	243,333	16,960	0.175%
				<u>\$8,910,000</u>		<u>\$8,613,958</u>	<u>\$521,024</u>	<u>5.387%</u>

APPENDIX IV
Page 2 of 2

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
AVERAGE COST OF LONG TERM DEBT
TWELVE MONTHS ENDING MAR. 31, 2010
(Thousands of Dollars)

Debentures			Due	Debt Outstanding 3/31/2010	Cost Rate	Average Balance 3/31/2010	Average Cost	Effective Cost Rate
Tax Exempt Debt								
1999	Series	A	05/01/34	292,700	1.6100%	292,700	4,712	0.049%
2001	Series	A	06/01/36	224,600	4.7000%	224,600	10,556	0.109%
2001	Series	B	10/01/36	98,000	1.6100%	98,000	1,578	0.016%
2004	Series	A	01/01/39	98,325	1.6100%	98,325	1,583	0.016%
2004	Series	B1	05/01/32	127,225	1.6100%	127,225	2,048	0.021%
2004	Series	B2	10/01/35	19,750	1.6100%	19,750	318	0.003%
2004	Series	C	11/01/39	70,125	2.6500%	70,125	1,858	0.019%
2005	Series	A	05/01/39	126,300	0.9200%	126,300	1,162	0.012%
				<u>\$1,057,025</u>		<u>\$1,057,025</u>	<u>\$23,816</u>	<u>0.246%</u>
<i>Subtotal:</i>						\$9,670,983	\$544,840	
Plus: Amortization of Debt Expense:							\$16,491	
Ending Balance of Unamortized Premium						\$30,664		
TOTAL:				<u>\$9,967,025</u>		<u>\$9,701,647</u>	<u>\$561,331</u>	<u>5.786%</u>

Note: Shaded Issuances and Expenses subject to reconciliation.

PUBLIC COMMENT CATEGORIES

- A. Opposes any rate increase generally.
- B. Opposes any rate increase in light of the weak economy.
- C. Opposes any rate increase because of the impacts on customers generally, and especially on the elderly, those on fixed incomes and the poor.
- D. The Commission should decide the rate case taking into account the customers' ability to pay.
- E. Any rate increase should be conditioned on the elimination of all Company "fat" (example: legal department) and all costs resulting from inefficiency.
- F. The Commission should decide the case balancing the need to restrain rate increases with the need for reliable service.
- G. The Company has been encouraging customers to use less electricity and now it is citing reduced customer usage as a reason for needing a rate increase. This is unfair.
- H. The PSC has not been doing a good job.
- I. The Company's profits are already adequate.
- J. I pay more for delivery than for commodity.
- K. Any rate increase should be conditioned on the elimination of 400 double and damaged poles in the neighborhood of the White Plains North Broadway Citizens Association.
- L. Any rate increase should be conditioned on an improvement in service quality in New Rochelle or generally.
- M. Given that oil prices have come down, the Company's rates should decrease rather than increase.
- N. EPA supports the proposed shore tariff to help clean the air and improve the health of New Yorkers, especially for low-income and minority persons. A rate setting work group should be quickly convened so that shore power can become a reality by the time the Commission decides the rate case.
- O. The proposed rate increase should be granted so that the Company will have money to invest in infrastructure and earn a decent rate of return.
- P. Any rate increase should be conditioned on stopping Company advertising that is unnecessary for a monopoly.
- Q. Miscellaneous: (1) Any rate increase should be conditioned on requiring the Company to install metal instead of wooden poles, as this is what is done in other states. (2) Concerned about frequent adjustments in budget billing amounts. (3) Rates should be rolled back. (4) Electric bills should be included in rent. (5) The Company's gas rates should be decreased.

SUMMARY AND CATEGORIES OF PUBLIC COMMENTS
(As of 4/2/09 5:50 p.m.)

Customer Comment Number	Category A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Category Q
1	x	x	x														
2	x			x													
3	x		x		x												
4						x											
5					x	x											
6	x																
7	x	x															
8	x																
9	x						x										
10	x						x										
11	x							x									
12	x	x															
13	x		x					x									
14	x								x	x							
15											x						
16	x	x										x					
17		x											x				
18	x	x						x									
19														x			
20															x		
21	x	x						x	x								
22	x															x	
23	x	x	x				x										
24					x												
25	x	x							x								
26	x				x		x										
27	x																
28	x	x							x				x				
29	x	x					x										x
30	x	x					x										x
31*																	
32	x	x					x										x
33	x	x		x													
34	x	x		x	x												
35	x				x												

* Customer Bill Complaint Forwarded to OCS

[illegible]

**Summary of
Consolidated Edison's Electric
Reliability Performance Mechanism
Effective January 1, 2009**

Various exclusions apply to these standards. Some are related to weather, third party actions, extraordinary circumstances, and catastrophic events.

	Requirement for Revenue Adjustment	Revenue Adjustment Exposure (millions)
Threshold Standards		
Network Outage Duration	Con Ed Performance > 4.90	\$5.0
CAIDI (radial) ⁵⁹⁸	Con Ed Performance > 1.85	\$5.0
Network Outages per 1000 customers	Con Ed Performance > 2.50	\$4.0
Summer Open Automatics (network)	Con Ed Performance > 510	\$1.0
SAIFI (radial) ⁵⁹⁹	Con Ed Performance > 0.530	\$5.0
Major Outages		
Network	The interruption of service to 10 percent or more of the customers in any network for a period of three hours or more.	\$10.0/event
Radial	One event that results in the sustained interruption of service to 70,000 customers for a period of three hours or more.	\$10.0/event
Maximum Exposure		\$30.0

⁵⁹⁸ CAIDI - Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.

⁵⁹⁹ SAIFI - System Average Interruption Frequency Index. It is the average number of times that a customer is interrupted per 1,000 customers served during the year.

**Summary of
Consolidated Edison's Electric
Reliability Performance Mechanism
Effective January 1, 2009**

Various exclusions apply to these standards. Some are related to weather, third party actions, extraordinary circumstances, and catastrophic events.

		Requirement for Revenue Adjustment	Revenue Adjustment Exposure (millions)																
Remote Monitoring System Reporting																			
Network		Failure by the Company to achieve 90 percent reporting rate for the Remote Monitoring System in each network during the last month of each quarter.	\$10.0/network																
	Maximum Exposure	\$50.0																	
Restoration																			
	Radial	Restoration of service that does not meet the following target. <table><tr><th colspan="2">Overhead Events</th></tr><tr><th>Emergency Level</th><th>Restoration Targets</th></tr><tr><td>1-Upgraded</td><td>1 Day</td></tr><tr><td>2-Serious</td><td>2 Days</td></tr><tr><td>3A-Serious</td><td>3 Days</td></tr><tr><td>3B-Full Scale (Tropical storm)</td><td>4 Days</td></tr><tr><td>3B-Full Scale (Hurricane Category 1-2)</td><td>7 Days</td></tr><tr><td>3B-Full Scale (Hurricane Category 3-5)</td><td>≤ 3 weeks</td></tr></table>	Overhead Events		Emergency Level	Restoration Targets	1-Upgraded	1 Day	2-Serious	2 Days	3A-Serious	3 Days	3B-Full Scale (Tropical storm)	4 Days	3B-Full Scale (Hurricane Category 1-2)	7 Days	3B-Full Scale (Hurricane Category 3-5)	≤ 3 weeks	\$0.0 (trial basis)
Overhead Events																			
Emergency Level	Restoration Targets																		
1-Upgraded	1 Day																		
2-Serious	2 Days																		
3A-Serious	3 Days																		
3B-Full Scale (Tropical storm)	4 Days																		
3B-Full Scale (Hurricane Category 1-2)	7 Days																		
3B-Full Scale (Hurricane Category 3-5)	≤ 3 weeks																		

**Summary of
Consolidated Edison's Electric
Reliability Performance Mechanism
Effective January 1, 2009**

Various exclusions apply to these standards. Some are related to weather, third party actions, extraordinary circumstances, and catastrophic events.

			Requirement for Revenue Adjustment	Revenue Adjustment Exposure (millions)
Program Standards				
	Pole Repair		For all similar poles that come into existence on or after 1/1/09, repairs not made within 30 days from the date the Company became aware of the "Damaged Pole" or "Double Damaged Pole" for at least 90% of these new "Damaged Poles" and "Double Damaged Poles". Also if all repairs are not completed within six months of the dates the poles are damaged.	\$3.0
	Shunt Removal			
			For all shunts that come into existence on or after 1/1/09, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 90% of these cases within 60 days during the remaining six months, May through October. Also if all repairs are not completed within six months of the dates the shunts are installed.	Winter \$1.5
				Summer \$1.5

**Summary of
Consolidated Edison's Electric
Reliability Performance Mechanism
Effective January 1, 2009**

Various exclusions apply to these standards. Some are related to weather, third party actions, extraordinary circumstances, and catastrophic events.

			Requirement for Revenue Adjustment	Revenue Adjustment Exposure (millions)
			No Current Street Lights and Traffic Signals	
			For all no currents that come into existence on or after 1/1/09, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 80% of these new cases within 45 days during the remaining six months, May through October. Also if all repairs are not completed within six months of the dates the no currents came into existence.	Winter \$1.5
				Summer \$1.5
		Over-Duty Circuit Breakers		
		Per Breaker	If Con Edison does not replace at least 60 over-duty circuit breakers during the rate year.	\$0.1
		Maximum Exposure		\$3.0
Total Revenue Adjustment Exposure: \$112				

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-170033 & UG-170034

MULTIPARTY SETTLEMENT
STIPULATION AND AGREEMENT

I. INTRODUCTION

1. This Settlement Stipulation and Agreement (“Settlement”) is entered into by and between the following parties in this case: (i) Puget Sound Energy (“PSE”), (ii) the Commission’s regulatory staff (“Commission Staff”),¹ (iii) the Industrial Customers of Northwest Utilities (“ICNU”), (iv) NW Energy Coalition/Renewable Northwest/Natural Resource Defense Council, (v) The Energy Project, (vi) Sierra Club, (vii) Federal Executive Agencies, (viii) The Kroger Co., (ix) the State of Montana, and (x) Northwest Industrial Gas Users (“NWIGU”) as of September 15, 2017 (the “Settlement Date”). These parties are hereinafter collectively referred to as “Settling Parties” and individually as a “Settling Party.”

2. This Settlement is a “multiparty settlement,” as that term is defined in WAC 480-07-730(3), because this Settlement is entered into by some, but not all, parties on one or more issues.

¹ In formal proceedings, such as this, the Commission’s regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners’ policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. See RCW 34.05.455.

3. This Settlement is subject to review and disposition by the Washington Utilities and Transportation Commission (“Commission”). Section III of the Settlement is effective on the date of the Commission order approving it (unless the Commission establishes a different effective date).

II. BACKGROUND AND NATURE OF THE DOCKET

4. On January 13, 2017, PSE filed with the Commission, in Dockets UE-170033 & UG-170034, tariff revisions to increase rates for electric and natural gas services provided to customers in Washington. The tariff revisions, if allowed to become effective, would have increased electric base rates by approximately \$149 million (7.6 percent) on an annual basis and increased natural gas base rates by approximately \$23 million (2.8 percent) on an annual basis. The net impact to customers after applying various offsets would be an increase in electric rates of approximately \$87 million (4.1 percent) and a decrease in natural gas rates of approximately \$22 million (–2.4 percent). The Commission suspended operation of the as-filed tariffs and set the matters for hearing in Order 01 on January 19, 2017. The Commission convened a prehearing conference in this proceeding at Olympia, Washington on February 13, 2017.

5. At various times established in its procedural schedule, and by several orders, the Commission accepted prefiled testimony and exhibits from PSE, Commission Staff, and other parties. The parties to the proceeding participated in settlement conferences on August 11, 2017, and August 24, 2017, and have participated in subsequent settlement-related calls and correspondence after those dates. On August 25, 2017, the Settling Parties reached an agreement in principle for the settlement on some, but not all issues, and agreed that remaining issues may be litigated and provided notice of this agreement in principle to Administrative Law Judge Moss.

6. On August 30, 2017, the Commission conducted evidentiary hearings on the remaining issues not resolved in the agreement in principle among the Settling Parties. In addition, the Commission conducted public comment hearings in PSE's service territory on July 31, 2017, and on August 31, 2017, during which the Commission received into the record oral comments and exhibits from interested members of the public.

III. AGREEMENT

A. Capital Structure and Cost of Capital

1. Capital Structure

7. The Settling Parties agree to a capital structure for PSE that includes 48.5 percent equity and 51.5 percent debt.

2. Cost of Equity

8. The Settling Parties agree to an authorized return on equity for PSE of 9.50 percent.

3. Costs of Debt

9. The Settling Parties agree to an authorized cost of debt for PSE of 5.81 percent.

4. Authorized Rate of Return

10. The Settling Parties agree to an overall authorized rate of return for PSE of 7.60 percent, as reflected in Table 1 below.

Table 1. Authorized Rate of Return

	Capital Structure	Cost	Weighted Cost
Debt	51.5%	5.81%	2.99%
Equity	48.5%	9.50%	4.61%
Overall Rate of Return	100.0%		7.60%

B. Revenue, Expense and Rate Base Restating and Pro Forma Adjustments

11. The Settling Parties agree to an overall electric revenue increase of \$20 million (or 0.9 percent increase) and an overall natural gas revenue decrease of \$35 million (or 3.8 percent decrease). For purposes of this Section III.B, the Settling Parties used as a common base (i) the Electric Results of Operations for the Twelve Months Ended September 30, 2016, as presented by Ms. Melissa Cheesman in Exh. MCC-2r, and (ii) the Gas Results of Operations for the Twelve Months Ended September 30, 2016, as presented by Ms. Melissa Cheesman in Exh. MCC-7r. All adjustment numbers and nomenclature in this Section III.B are identical to those presented in Exh. MCC-2r for electric operations and Exh. MCC-7r for natural gas operations. Additionally, the Settling Parties present a table of all agreed-upon revenue, expense and rate base restating and pro forma adjustments consistent with this Settlement as Exhibit A to this Settlement.

1. Actual Results of Operations

a. Actual Results of Operations for Electric Operations

12. The actual results of electric operations for the test year are uncontested and consist of (i) net operating income of \$401,002,972 and (ii) rate base of \$5,153,204,462. (*See, e.g.,* Cheesman, Exh. MCC-2r at 2.)

b. Actual Results of Operations for Natural Gas Operations

13. The actual results of natural gas operations for the test year are uncontested and consist of (i) net operating income of \$119,145,769 and (ii) rate base of \$1,727,319,760. (*See, e.g.,* Cheesman, Exh. MCC-7r at 2.)

2. Common Adjustments

a. Revenues and Expenses

i. Adjustment No. 13.01 – Revenues and Expenses (Electric)

14. Adjustment No. 13.01 – Revenues and Expenses is uncontested and decreases net operating income for electric operations by \$29,139,114. (*See, e.g.*, Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.01 – Revenues and Expenses (Natural Gas)

15. Adjustment No. 11.01 – Revenues and Expenses is uncontested and decreases net operating income for natural gas operations by \$32,674,131. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

b. Temperature Normalization

i. Adjustment No. 13.02 – Temperature Normalization (Electric)

16. The Settling Parties accept, for purpose of settlement, Adjustment No. 13.02 – Temperature Normalization proposed by PSE, which increases net operating income for electric operations by \$17,527,344. (*See* Barnard, Exh. KJB-19 at 2 (labeled therein as “Adjustment No. 20.02 – Temperature Normalization”).) The Settling Parties do not agree to any methodology for temperature normalization going forward and expressly reserve the right to address similar modifications in subsequent proceedings.

ii. Adjustment No. 11.02 – Temperature Normalization (Natural Gas)

17. The Settling Parties accept, for purposes of settlement, Adjustment No. 11.02 – Temperature Normalization proposed by PSE, which increases net operating income for natural gas operations by \$16,046,445. (*See* Free, Exh. SEF-14 at 2 (labeled therein as “Adjustment No. 15.02 – Temperature Normalization”).) The Settling Parties do not agree to any

methodology for temperature normalization going forward and expressly reserve the right to address similar modifications in subsequent proceedings.

c. Pass-Through Revenues and Expenses

i. Adjustment No. 13.03 – Pass-Through Revenues and Expenses (Electric)

18. Adjustment No. 13.03 – Pass-Through Revenues and Expenses is uncontested and decreases net operating income for electric operations by \$1,000,540. (*See, e.g.*, Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.03 – Pass-Through Revenues and Expenses (Natural Gas)

19. Adjustment No. 11.03 – Pass-Through Revenues and Expenses is uncontested and increases net operating income for natural gas operations by \$736,148. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

d. Federal Income Tax

i. Adjustment No. 13.04 – Federal Income Tax (Electric)

20. Adjustment No. 13.04 – Federal Income Tax is uncontested and decreases net operating income for electric operations by \$27,023,239. (*See, e.g.*, Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.04 – Federal Income Tax (Natural Gas)

21. Adjustment No. 11.04 – Federal Income Tax is uncontested and increases net operating income for natural gas operations by \$700,822. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

e. Tax Benefit of Pro Forma Interest

i. Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest (Electric)

22. No party contested the manner in which Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest should be calculated, although parties differed in the result based on the rate base items included. Based upon the rate base items included in this Settlement, the Settling Parties agree that Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest increases net operating income for electric operations by \$54,067,781.²

ii. Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest (Natural Gas)

23. No party contested the manner in which Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest should be calculated, although parties differed in the result based on the rate base items included. Based upon the rate base items included in this Settlement, the Settling Parties agree that Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest increases net operating income for natural gas operations by \$18,475,298.³

f. Depreciation Study

i. Adjustment No. 13.06 – Depreciation Study (Electric)

24. The Settling Parties agree to use the depreciation study provided by PSE as the Second Exhibit to the Prefiled Direct Testimony of Mr. John J. Spanos, Exhibit JJS-3r, subject to modifications with respect to (i) Colstrip Units 1 and 2 identified in paragraph 25 below and (ii) Colstrip Units 3 and 4 identified in paragraph 26 below. Please see Exhibit B to this

² Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest is equal to the product of (i) electric rate base of \$5,166,534,272, multiplied by (ii) the weighted average cost of debt of 2.99%, multiplied by (iii) the federal tax rate of 35 percent.

³ Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest is equal to the product of (i) natural gas rate base of \$1,765,436,979, multiplied by (ii) the weighted average cost of debt of 2.99%, multiplied by (iii) the federal tax rate of 35 percent.

Settlement for the electric depreciation study adjustment and the agreed-upon electric depreciation rates that result from this Settlement.

25. The Settling Parties agree to set depreciation rates for Colstrip Units 1 and 2 at amounts that will yield annual depreciation expense of \$18.5 million for the remaining operational lives of those units. The resulting depreciation rates are included on pages 12 and 13 of Exhibit B to this Settlement. At closure of Units 1 and 2, PSE shall offset all additional unrecovered plant balances for Colstrip Units 1 and 2 with monetized production tax credits (“PTCs”). PSE assumes the risk that it is unable to monetize the PTCs to offset additional unrecovered plant balances for Colstrip Units 1 and 2; provided, however that if Colstrip Units 1 and 2 close prior to the monetization of sufficient PTCs to offset additional unrecovered plant balances for Colstrip Units 1 and 2, PSE shall hold remaining unrecovered plant balances of Colstrip Units 1 and 2 in a regulatory asset in rate base until the earlier to occur of (i) the recovery of all plant balances for Colstrip Units 1 and 2 through monetized PTC offsets or (ii) December 31, 2029.

26. The Settling Parties agree to a depreciation schedule for Colstrip Units 3 and 4 that assumes a remaining useful life of those units through December 31, 2027. The Settling Parties understand that December 31, 2027, is a stipulated depreciation life for Colstrip Units 3 and 4. The resulting depreciation rates for Units 3 and 4 are included on pages 2 and 3 of Exhibit B to this Settlement.

27. The Settling Parties agree that Adjustment No. 13.06 – Depreciation Study (i) decreases net operating income for electric operations by \$34,311,788 and (ii) decreases rate base for electric operations by \$17,155,894, as is shown on page 1 of Exhibit B to this Settlement.

ii. Adjustment No. 11.06 – Depreciation Study (Natural Gas)

28. The Settling Parties agree to use the depreciation study provided by PSE as the Second Exhibit to the Prefiled Direct Testimony Mr. John J. Spanos, Exhibit JJS-3r. The Settling Parties further agree that Adjustment No. 11.06 – Depreciation Study is uncontested for natural gas operations and (i) increases net operating income for natural gas operations by \$13,174,098 and (ii) increases rate base for natural gas operations by \$6,587,049. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

g. Regulatory Asset Colstrip

29. The Settling Parties agree not to use Adjustment No. 13.06A – Reg. Asset Colstrip proposed by Commission Staff. Accordingly, Adjustment No. 13.06A – Reg. Asset Colstrip has no effect on either net operating income or rate base for electric operations.

h. Normalize Injuries and Damages

i. Adjustment No. 13.07 – Normalize Injuries and Damages (Electric)

30. Adjustment No. 13.07 – Normalize Injuries and Damages is uncontested and increases net operating income for electric operations by \$69,387. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.07 – Normalize Injuries and Damages (Natural Gas)

31. Adjustment No. 11.07 – Normalize Injuries and Damages is uncontested and decreases net operating income for natural gas operations by \$57,738. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

i. Bad Debts

i. Adjustment No. 13.08 – Bad Debts (Electric)

32. Adjustment No. 13.08 – Bad Debts is uncontested and increases net operating income for electric operations by \$681,065. (*See, e.g.,* Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.08 – Bad Debts (Natural Gas)

33. Adjustment No. 11.08 – Bad Debts is uncontested and increases net operating income for natural gas operations by \$35,240. (*See, e.g.,* Cheesman, Exh. MCC-7r at 3.)

j. Incentive Pay

i. Adjustment No. 13.09 – Incentive Pay (Electric)

34. Adjustment No. 13.09 – Incentive Pay is uncontested and decreases net operating income for electric operations by \$109,903. (*See, e.g.,* Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.09 – Incentive Pay (Natural Gas)

35. Adjustment No. 11.09 – Incentive Pay is uncontested and increases net operating income for natural gas operations by \$104,023. (*See, e.g.,* Cheesman, Exh. MCC-7r at 3.)

k. Directors & Officers Insurance

i. Adjustment No. 13.10 – Directors & Officers Insurance (Electric)

36. Adjustment No. 13.10 – Directors & Officers Insurance is uncontested and increases net operating income for electric operations by \$16,141. (*See, e.g.,* Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.10 – Directors & Officers Insurance (Natural Gas)

37. Adjustment No. 11.10 – Directors & Officers Insurance is uncontested and increases net operating income for natural gas operations by \$11,636. (*See, e.g.,* Cheesman, Exh. MCC-7r at 3.)

I. Interest on Customer Deposits

i. Adjustment No. 13.11 – Interest on Customer Deposits (Electric)

38. Adjustment No. 13.11 – Interest on Customer Deposits is uncontested and decreases net operating income for electric operations by \$176,606. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.11 – Interest on Customer Deposits (Natural Gas)

39. Adjustment No. 11.11 – Interest on Customer Deposits is uncontested and decreases net operating income for natural gas operations by \$50,137. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

m. Rate Case Expenses

i. Adjustment No. 13.12 – Rate Case Expenses (Electric)

40. The Settling Parties agree to use Adjustment No. 13.12 – Rate Case Expenses proposed by PSE, which decreases net operating income for electric operations by \$264,905. (*See* Barnard, Exh. KJB-19 at 3 (labeled therein as “Adjustment No. 20.12 – Rate Case Expenses”).)

ii. Adjustment No. 11.12 – Rate Case Expenses (Natural Gas)

41. The Settling Parties agree to use Adjustment No. 11.12 – Rate Case Expenses proposed by PSE, which decreases net operating income for natural gas operations by \$280,617. (*See* Free, Exh. SEF-14 at 3 (labeled therein as “Adjustment No. 15.12 – Rate Case Expenses”).)

n. Deferred Gains/Losses on Property Sales

i. Adjustment No. 13.13 – Deferred Gains/Losses on Property Sales (Electric)

42. Adjustment No. 13.13 – Deferred Gains/Losses on Property Sales is uncontested and increases net operating income for electric operations by \$171,200. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.13 – Deferred Gains/Losses on Property Sales (Natural Gas)

43. The Settling Parties agree to use Adjustment No. 11.13 – Deferred Gains/Losses on Property Sales proposed by PSE, which decreases net operating income for natural gas operations by \$105,090. (*See* Free, Exh. SEF-14 at 3 (labeled therein as “Adjustment No. 15.13 – Deferred Gains/Losses on Property Sales”).)

o. Property & Liability Insurance

i. Adjustment No. 13.14 – Property & Liability Insurance (Electric)

44. Adjustment No. 13.14 – Property & Liability Insurance is uncontested and increases net operating income for electric operations by \$66,147. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.14 – Property & Liability Insurance (Natural Gas)

45. Adjustment No. 11.14 – Property & Liability Insurance is uncontested and increases net operating income for natural gas operations by \$45,174. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

p. Pension Plan

i. Adjustment No. 13.15 – Pension Plan (Electric)

46. The Settling Parties agree to use Adjustment No. 13.15 – Pension Plan proposed by each of PSE and Commission Staff, which decreases net operating income for electric operations by \$1,184,945. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4; Barnard, Exh. KJB-19 at 4 (labeled therein as “Adjustment No. 20.15 – Pension Plan”).)

ii. Adjustment No. 11.15 – Pension Plan (Natural Gas)

47. The Settling Parties agree to use the Adjustment No. 11.15 – Pension Plan proposed by each of PSE and Commission Staff, which decreases net operating income for natural gas operations by \$572,091. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3; Free, Exh. SEF-14 at 3 (labeled therein as “Adjustment No. 15.15 – Pension Plan”).)

q. Wage Increase

i. Adjustment No. 13.16 – Wage Increase (Electric)

48. Adjustment No. 13.16 – Wage Increase is uncontested and decreases net operating income for electric operations by \$1,357,716. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.16 – Wage Increase (Natural Gas)

49. Adjustment No. 11.16 – Wage Increase is uncontested and decreases net operating income for natural gas operations by \$907,409. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

r. Investment Plan

i. Adjustment No. 13.17 – Investment Plan (Electric)

50. Adjustment No. 13.17 – Investment Plan is uncontested and decreases net operating income for electric operations by \$96,705. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.17 – Investment Plan (Natural Gas)

51. Adjustment No. 11.17 – Investment Plan is uncontested and decreases net operating income for natural gas operations by \$46,689. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

s. Employee Insurance

i. Adjustment No. 13.18 – Employee Insurance (Electric)

52. Adjustment No. 13.18 – Employee Insurance is uncontested and decreases net operating income for electric operations by \$121,751. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.18 – Employee Insurance (Natural Gas)

53. Adjustment No. 11.18 – Employee Insurance is uncontested and decreases net operating income for natural gas operations by \$58,781. (*See, e.g.*, Cheesman, Exh. MCC-7r at 4.)

t. Environmental Remediation

i. General Provisions Related to Environmental Remediation

54. Within six months of filing of this Settlement with the Commission, PSE and Commission Staff shall commence a process to determine a methodology for assigning insurance recoveries received by PSE in a manner that does not potentially compromise PSE’s litigation position associated with such insurance recoveries. PSE and Commission Staff shall provide an update regarding such process in the earlier to occur of either (i) PSE’s next general rate case proceeding or (ii) any expedited rate filing (“ERF”) or limited rate proceeding of PSE to revise transmission and distribution rates.

55. In lieu of quarterly environmental reports, PSE shall submit annual environmental reports no later than April 30 of the following year that contain the following information:

- (a) Project amounts authorized for deferral with the Commission docket and order number that gives authority to PSE to do so.
- (b) Beginning date of the deferral of each project.
- (c) Beginning balances at the start of deferral.
- (d) Monthly balances and the year-end deferred balance for the reporting year.
- (e) Location of projects and internal naming convention (e.g., Tacoma Tar Pits and/or Tide Flats).
- (f) Total amount of third party and insurance recoveries received during the reporting year by month. Where possible, recoveries received by PSE will reduce the balance of corresponding project cost balances. If PSE receives lump sums for multiple projects, documentation that supports all the projects that caused the claim against third party and insurance should be included in the report.
- (g) PSE shall record costs incurred for newly established electric and gas remediation sites in FERC account 186. Balances of projects that have been authorized for amortization and are currently being amortized should be transferred to FERC account 182.3. All projects that are newly established or are being amortized should be included in the annual report to the Commission, along with Commission's order that authorized deferral number, Commission's order that authorized amortization, beginning balances when the amortization started, year end balances, and amortization start and end date.

Notwithstanding the foregoing, after the conclusion of the process for assigning insurance recoveries conducted pursuant to paragraph 54 of this Settlement, PSE shall report specific recoveries associated with specific projects consistent with the terms and conditions developed in such process.

ii. Adjustment No. 13.19 – Environmental Remediation (Electric)

56. The Settling Parties agree to use Adjustment No. 13.19 – Environmental Remediation proposed by PSE, which decreases net operating income for electric operations by

\$925,460. (See Barnard, Exh. KJB-19 at 4 (labeled therein as “Adjustment No. 20.19 – Environmental Remediation”).)

iii. Adjustment No. 11.19 – Environmental Remediation (Natural Gas)

57. The Settling Parties agree to use Adjustment No. 11.19 – Environmental Remediation proposed by PSE, which decreases net operating income for natural gas operations by \$5,592,128. (See Free, Exh. SEF-14 at 4 (labeled therein as “Adjustment No. 15.19 – Environmental Remediation”).)

u. Payment Processing Costs

i. Adjustment No. 13.20 – Payment Processing Costs (Electric)

58. The Settling Parties agree to use Adjustment No. 13.20 – Payment Processing Costs proposed by PSE, Public Counsel, and Commission Staff, which decreases net operating income for electric operations by \$2,010,221. (See, e.g., Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.20 – Payment Processing Costs (Natural Gas)

59. The Settling Parties agree to use Adjustment No. 11.20 – Payment Processing Costs proposed by PSE, Public Counsel, and Commission Staff, which decreases net operating income for natural gas operations by \$1,449,117. (See, e.g., Cheesman, Exh. MCC-7r at 4.)

v. South King Service Center

i. Adjustment No. 13.21 – South King Service Center (Electric)

60. Adjustment No. 13.21 – South King Service Center is uncontested and (i) increases net operating income for electric operations by \$434,046 and (ii) increases rate base for electric operations by \$15,915,060. (See, e.g., Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.21 – South King Service Center (Natural Gas)

61. Adjustment No. 11.21 – South King Service Center is uncontested and (i) increases net operating income for natural gas operations by \$212,048 and (ii) increases rate base for natural gas operations by \$7,775,116. (*See, e.g.,* Cheesman, Exh. MCC-7r at 4.)

w. Excise Tax and WUTC Filing Fee

i. Adjustment No. 13.22 – Excise Tax and WUTC Filing Fee (Electric)

62. Adjustment No. 13.22 – Excise Tax and WUTC Filing Fee is uncontested and increases net operating income for electric operations by \$10,262. (*See, e.g.,* Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.22 – Excise Tax and WUTC Filing Fee (Natural Gas)

63. Adjustment No. 11.22 – Excise Tax and WUTC Filing Fee is uncontested and increases net operating income for natural gas operations by \$33,509. (*See, e.g.,* Cheesman, Exh. MCC-7r at 4.)

x. Investor-Supplied Working Capital and Rate Base Adjustment

i. Adjustment No. 13.23 – ISWC and RB Adjustment (Electric)

64. The Settling Parties agree to base Adjustment No. 13.23 – ISWC and RB Adjustment on Adjustment 20.23 – Working Capital proposed by PSE; *provided, however*, that PSE shall include construction work in progress (“CWIP”) in the non-operating category for purposes of allocating investor-supplied working capital among electric, gas, and non-utility operations. The calculation of investor-supplied working capital agreed to by the Settling Parties is included as Exhibit C to this Settlement. The Settling Parties agree that Adjustment

No. 13.23 – ISWC and RB Adjustment increases rate base for electric operations by \$19,006,090.

ii. Adjustment No. 11.23 – ISWC and RB Adjustment (Natural Gas)

65. The Settling Parties agree to base Adjustment No. 11.23 – ISWC and RB Adjustment on Adjustment 15.23 – Working Capital proposed by PSE; *provided, however*, that PSE shall include CWIP in the non-operating category for purposes of allocating investor-supplied working capital among electric, gas, and non-utility operations. The calculation of investor-supplied working capital agreed to by the Settling Parties is included as Exhibit C to this Settlement. The Settling Parties agree that Adjustment No. 11.23 – ISWC and RB Adjustment increases rate base for natural gas operations by \$4,743,346.

y. Legal Cost

i. Adjustment No. 13.24 – Legal Cost (Electric)

66. The Settling Parties agree not to make Adjustment No. 13.24 – Legal Cost proposed by Commission Staff. Accordingly, Adjustment No. 13.24 – Legal Cost has no effect on either net operating income or rate base for electric operations.

ii. Adjustment No. 11.24 – Legal Cost (Natural Gas)

67. The Settling Parties agree not to use Adjustment No. 11.24 – Legal Cost proposed by Commission Staff. Accordingly, Adjustment No. 11.24 – Legal Cost has no effect on either net operating income or rate base for natural gas operations.

z. Black Box Adjustment

i. Adjustment No. 13.25 – Black Box Adjustment (Electric)

68. The Settling Parties agree to Adjustment No. 13.25 – Black Box Adjustment, which decreases the revenue requirement for electric operations by \$1 million to address all

remaining electric revenue requirement issues that differ from PSE's rebuttal case filed in this proceeding on August 9, 2017. Each of the Settling Parties reserves its right to make arguments on methodologies for these and other issues in future cases without prejudice. Adjustment No. 13.25 – Black Box Adjustment increases net operating income for electric operations by \$619,051, which is equal to the product of (i) \$1,000,000, multiplied by (ii) the electric conversion factor of 0.952386,⁴ multiplied by (iii) the difference between (a) 100 percent, minus (b) the federal tax rate of 35 percent.

ii. Adjustment No. 11.25 – Black Box Adjustment (Natural Gas)

69. The Settling Parties agree to Adjustment No. 11.25 – Black Box Adjustment, which decreases the revenue requirement for natural gas operations by \$1.5 million to address all remaining natural gas revenue requirement issues that differ from PSE's rebuttal case filed in this proceeding on August 9, 2017. Each of the Settling Parties reserves its right to make arguments on methodologies for these and other issues in future cases without prejudice. Adjustment No. 11.25 – Black Box Adjustment increases net operating income for natural gas operations by \$930,675, which is equal to the product of (i) \$1,500,000, multiplied by (ii) the electric conversion factor of 0.954538,⁵ multiplied by (iii) the difference between (a) 100 percent, minus (b) the federal tax rate of 35 percent.

3. Electric-Only Adjustments

a. Adjustment No. 14.01 – Power Costs

70. The Settling Parties agree to base Adjustment No. 14.01 – Power Costs as proposed by PSE in Adjustment 21.01– Power Costs, subject to the following modifications:

- (i) PSE shall remove all costs associated with compliance with the Clean Air Rule from power costs in this proceeding;

⁴ See, e.g., Cheesman, Exh. MCC-3r at 3.

⁵ See, e.g., Cheesman, Exh. MCC-8r at 3.

- (ii) PSE shall use the same wind resource capacity factors used to determine power costs for purposes of establishing rates in Docket UE-111048 to determine power costs in this proceeding; and
- (iii) PSE shall remove major maintenance adders from the AURORA dispatch model in determining power costs in this proceeding.
- (iv) PSE shall remove both the costs and benefits associated with the California Independent System Operator (“CAISO”) Energy Imbalance Market (“EIM”).

The Settling Parties acknowledge that these modifications represent a compromise for settlement purposes only, and each Settling Party expressly reserves the right to advocate different positions in subsequent proceedings.

71. The Settling Parties support approval of a deferral mechanism in this proceeding, by which PSE will be allowed to defer Clean Air Rule compliance costs for future recovery once Clean Air Rule compliance requirements and obligations are finally determined. This will depend on (i) the timing of when Clean Air Rule compliance costs become known and measurable and (ii) the materiality of such compliance costs, the Settling Parties that intend to take a position on this issue will work together to include prudent Clean Air Rule costs in PSE’s Power Cost Adjustment (“PCA”) baseline rate as expeditiously as possible.

72. The Settling Parties agree that the moratorium on changes to the PCA mechanism adopted in Docket UE-130617 shall remain in effect. For purposes of this Settlement, however, the Settling Parties agree to Commission Staff’s proposal that a line item for all costs related to the CAISO EIM be included as actual costs in the annual PCA filing that determines whether PSE over- or under-collected on power costs. For purposes of calculating the PCA imbalance in the PCA mechanism, the Settling Parties agree to include the amount for capital items (depreciation and return on) and labor related to the CAISO EIM included in Exhibit D to this Settlement as a line-item in actual allowed power costs in Schedule B. PSE shall include these

costs in Schedule B in a manner similar to the Equity Adder for the Coal Transition PPA in that they will be included in the Adjustments section (currently shown on lines 52 through 57 in PSE's 2016 Annual PCA Compliance Filing in Docket No. UE-170334) of Schedule B. These rows adjust the variable costs associated with power costs not represented in actual expenses booked to the power cost accounts.

73. The Settling Parties agree that Adjustment No. 14.01 – Power Costs increases net operating income for electric operations by \$1,185,175, the calculation of which is provided as Exhibit E to this Settlement.

b. Adjustment No. 14.02 – Montana Electric Energy Tax

74. No party contested the manner in which Adjustment No. 14.02 – Montana Electric Energy Tax should be calculated, but changes to power costs affect the associated taxes. The impact of this increases net operating income for electric operations by \$148,016. Please see Exhibit E to this Settlement for the calculation of Adjustment No. 14.02 – Montana Electric Energy Tax.

c. Adjustment No. 14.03 – Wild Horse Solar

75. Adjustment No. 14.03 – Wild Horse Solar is uncontested and (i) increases net operating income for electric operations by \$137,890 and (ii) decreases rate base for electric operations by \$1,969,341. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

d. Adjustment No. 14.04 – ASC 815 (Prev. SFAS 133)

76. Adjustment No. 14.04 – ASC 815 (Prev. SFAS 133) is uncontested and decreases net operating income for electric operations by \$41,672,584. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

e. Adjustment No. 14.05 – Storm Damage

77. PSE shall defer the costs of any storms that occur on or after the Settlement Date and on or before December 31, 2017, under the terms of the storm loss deferral mechanism established in Order 6 in Dockets UE-040641 & UG-040640, *et al.*, and as revised in Order 12 in Dockets UE-072300 & UG-072301 (the “Qualifying Storm Loss Deferral Mechanism”). PSE shall propose amortization of any such storm costs deferred pursuant to the terms of the prior sentence for recovery in PSE’s next general rate case or any ERF or limited rate proceeding to revise transmission and distribution rates.

78. PSE shall retain the Qualifying Storm Loss Deferral Mechanism for any storm costs incurred on or after January 1, 2018, subject to the following modifications: (i) the cumulative annual cost threshold for deferral of storms under the Qualifying Storm Loss Deferral Mechanism shall be increased from \$8 million to \$10 million, (ii) qualifying events that cost less than \$500,000 will not qualify for deferral, and (iii) the cumulative annual cost threshold for the Qualifying Storm Loss Deferral Mechanism shall exclude storm events with costs less than \$500,000.

79. The Settling Parties agree to a six-year average of \$10,656,246 million for normalized storm expense.

80. The Settling Parties acknowledge that PSE has an over-amortization of \$12,560,038 associated with the 2010 storms. PSE shall use the over-amortization to absorb the remaining balance of December 2006 wind storm and the remaining balance of the over-amortization to reduce the balance of the January 2012 snowstorm. PSE shall amortize remaining storm deferrals, over four years, once approved for recovery in rates; provided, however, that PSE shall amortize the January 2012 snowstorm over six years.

81. The Settling Parties agree that PSE shall calculate normalized operating income, for purposes of PSE's Earnings Sharing Mechanism by removing the storm normalization adjustment from PSE's annual Commission Basis Report per WAC 480-100-257.

82. The Settling Parties agree that Adjustment No. 14.05 – Storm Damage decreases net operating income for electric operations by \$6,137,438, the calculation of which is provided as Exhibit F to this Settlement.

f. Adjustment No. 14.06 – Regulatory Assets and Liabilities

83. Adjustment No. 14.06 – Regulatory Assets and Liabilities is uncontested and (i) increases net operating income for electric operations by \$1,736,212 and (ii) decreases rate base for electric operations by \$44,085,326. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

g. Adjustment No. 14.07 – Glacier Battery Storage

84. Adjustment No. 14.07 – Glacier Battery Storage is uncontested and (i) decreases net operating income for electric operations by \$145,490 and (ii) increases rate base for electric operations by \$2,842,787. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

h. Adjustment No. 14.08 – Energy Imbalance Market

85. The Settling Parties agree not to make Adjustment No. 14.08 – Energy Imbalance Market proposed by PSE. Accordingly, Adjustment No. 14.08 – Energy Imbalance Market has no effect on either net operating income or rate base for electric operations.

i. Adjustment No. 14.09 – Goldendale Capacity Upgrade

86. Adjustment No. 14.09 – Goldendale Capacity Upgrade is uncontested and (i) increases net operating income for electric operations by \$2,156 and (ii) increases rate base for electric operations by \$18,140,954. (*See, e.g.,* Cheesman, Exh. MCC-2r at 6.)

j. Adjustment No. 14.10 – Mint Farm Capacity Upgrade

87. Adjustment No. 14.10 – Mint Farm Capacity Upgrade is uncontested and increases rate base for electric operations by \$19,004,590. (*See, e.g.*, Cheesman, Exh. MCC-2r at 6.)

k. Adjustment No. 14.11 – White River

88. The Settling Parties agree to use Adjustment No. 14.11 – White River proposed by PSE, which (i) decreases net operating income for electric operations by \$3,288,310 and (ii) decreases rate base for electric operations by \$4,108,724. (*See* Barnard, Exh. KJB-19 at 6 (labeled therein as “Adjustment No. 21.11 – White River”).)

l. Adjustment No. 14.12 – Reclass of Hydro Treasury Grants

89. The Settling Parties agree to use Adjustment No. 14.12 – Reclass of Hydro Treasury Grants proposed by PSE, which (i) decreases net operating income for electric operations by \$2,131,857 and (ii) increases rate base for electric operations by \$5,739,615. (*See* Barnard, Exh. KJB-19 at 6 (labeled therein as “Adjustment No. 21.12 – Reclass of Hydro Treasury Grants”).)

m. Adjustment No. 14.13 – Production Adjustment

90. The Settling Parties agree to use Adjustment No. 14.13 – Production Adjustment proposed by PSE, which uses the variable production factor of 3.839 percent. The Settling Parties also agree that there should be no Fixed Production Factor used in this adjustment as a result of the agreements made in the decoupling section below. The Settling Parties agree that Adjustment No. 14.13 – Production Adjustment increases net operating income for electric operations by \$32,769, the calculation of which is provided as Exhibit G to this Settlement.

4. Gas-Only Adjustment – Adjustment 7.01 – Cost Recovery Mechanism

91. Adjustment No. 7.01 – Cost Recovery Mechanism is uncontested and (i) decreases net operating income for natural gas operations by \$4,003,724 and (ii) increases rate base for natural gas operations by \$19,011,708. (*See, e.g.*, Cheesman, Exh. MCC-7r at 4.)

5. PCA Baseline Rate – Previously Exh. KJB-22

92. This Settlement results in a PCA baseline rate of \$32.895 per MWh for PSE. Please see page 1 of Exhibit H to this Settlement for the calculation of this PCA baseline rate. PSE shall use this PCA baseline rate of \$32.895 per MWh for purposes of calculating the imbalance for sharing in PSE's PCA mechanism beginning with the date rates become effective in this proceeding. Please also see Exhibit H to this Settlement for (i) a calculation of the PCA baseline rate that will results once Microsoft takes service under a special contract and (ii) a calculation of the impact on Schedule 95 rates that would occur in a filing to be made once Microsoft takes service under the special contract. Exhibit H to this Settlement represents updated information originally discussed in the Prefiled Supplemental Direct Testimony of Katherine J. Barnard, Exh. KJB-10T, at page 11, line 14, through page 13, line 23.

C. Rate Spread and Rate Design

93. The Settling Parties have advocated for a variety of methodologies the Commission might use for resolving cost of service and rate spread issues in this proceeding. Except as otherwise set forth in this Settlement, the Settling Parties have not agreed upon any particular methodology, and the Settlement does not attempt to resolve those issues. PSE, Commission Staff, and other interested parties agree to participate in good faith in the ongoing generic proceeding to address cost of service and rate spread methodologies to be used in future cases.

1. Electric Rate Spread and Rate Design

a. Electric Rate Spread

94. The Settling Parties agree to change the allocation of PSE's electric revenue deficiency for Schedules 7A, 10, 11, 12, 25, 26, 29, 31, 46, and 49 from 75 percent to 65 percent of the average rate increase.

b. Electric Schedule 25

95. The Settling Parties agree with the Kroger proposal to (i) keep the tail-block energy rate of Schedule 25 at its current level, (ii) increase the Schedule 25 basic charge as proposed by PSE, and (iii) raise demand rates (and a portion of the first block energy rates) to recover the remainder of the revenue requirement spread to this schedule.

c. Electric Schedule 40

96. The Settling Parties agree with the Commission Staff proposal that Schedule 40 should be discontinued over time. Only customers on Schedule 40 as of the Settlement Date shall remain on Schedule 40, and Schedule 40 shall be closed to new customers. Customers on Schedule 40 as of the Settlement Date may remain on Schedule 40 for a period no later than the effective date of the tariffs resulting from PSE's next general rate proceeding, and PSE will work with such existing Schedule 40 customers to transition to electric service pursuant to one or more other PSE electric rate schedules.

d. Electric Schedules 46 and 49 Demand Charges

97. The Settling Parties agree to the increase of 48 percent to the demand charges for Schedules 46 and 49 proposed by Commission Staff.

e. Microsoft Recalculation

98. The Settling Parties agree that, when Microsoft is removed from Schedule 40, the allowed revenue per customer for other schedules will be recalculated consistent with the

contingent allowed revenue calculations illustrated in Exhibit JAP-43 for all customers that continue to be a part of PSE's electric decoupling rate mechanism at such time.

f. Ardmore Substation

99. The Settling Parties agree to a one-time revenue adjustment that removes from the applicable Schedule 40 customers \$250,000 of Ardmore Substation costs and reallocates such costs to other schedules. The Settling Parties acknowledge that this one-time revenue adjustment represents a compromise for settlement purposes only, and each Settling Party expressly reserves the right to address the issue of Ardmore Substation cost allocation in subsequent proceedings.

2. Natural Gas Rate Spread and Rate Design

100. The Settling Parties agree that all issues with respect to natural gas rate spread and rate design are not affected by this Settlement and are subject to litigation before the Commission.

D. Service Quality Index (SQI) No. 5

101. PSE shall revise Service Quality Index (SQI) No. 5 to establish an annual benchmark of 80 percent of calls answered within 60 seconds. The calculation will not include Integrated Voice Response System (IVR) transactions.

E. Low-Income Issues

102. The Settling Parties agree to PSE's proposal to increase the annual level of low-income electric assistance Home Energy Lifeline Program ("HELP") funding by double the corresponding overall percent rate increase to the residential electric class that is approved by the Commission in this proceeding.⁶ The amount of the percentage increase to the residential electric class shall be calculated in a manner consistent with column (y) of Exhibit JAP-44. Double this

⁶ The base funding for HELP of \$21,200,000 was approved in Dockets UE-121697/UG-121705. Approved additions were made to this level of HELP funding on October 1, 2013; October 1, 2014; October 1, 2015; and October 1, 2016. Thus, the total funding level approved for HELP is currently \$23,502,979.

percentage shall be added to the electric Schedule 129 low income tariff filings following the conclusion of this proceeding. Except for the redistribution of funds pursuant to paragraph 103, the Settling Parties agree to PSE's proposal to maintain the annual level of low-income natural gas assistance HELP funding at the same level as the current program year notwithstanding the decrease in rates for the natural gas residential class proposed in this Settlement.

103. The Settling Parties agree to PSE's proposal to change Schedule 129 tariffs so that the HELP funding will be distributed to electric and natural gas customers at 80% electric and 20% gas, respectively, going forward. PSE reserves the right to revisit this allocation in future rate proceedings. PSE will work with the Community Action Partnership agencies ("Agencies") to explore ways to adjust the allocation if necessary to target and utilize funds throughout a program year so that low-income customer needs are better met.

104. The Settling Parties agree to PSE's proposal to modify Schedule 129 for electric and natural gas service to allow senior, disabled, and other steady-income customers to certify their HELP eligibility for a two-year period. Such customers must meet the existing HELP criteria and elect to certify eligibility for two years after demonstrating a steady income that meets 150% of the federal poverty level, established by steady-income payment documentation.

105. PSE shall consult with The Energy Project and Agencies jointly regarding any initiatives or modifications affecting operation or administration by the agencies of bill assistance or weatherization programs.

106. PSE shall not proceed with implementation of third party scheduling of HELP/weatherization appointments until the proposal has been discussed with The Energy Project and affected agencies jointly and reviewed by the Advisory Committee.

107. The Settling Parties agree to the establishment of an Advisory Committee for PSE bill assistance. The Advisory Committee shall be formed no later than January 1, 2018, and the first meeting of the Advisory Committee shall occur no later than March 1, 2018. The Advisory Committee shall include representatives from PSE, The Energy Project, Commission Staff, Public Counsel, and other interested stakeholders. The costs of the Advisory Committee will be recovered through general rates, similar to the manner in which Avista is authorized to recover such costs. The goals of the Advisory Committee are (i) to keep customers connected to their energy service; (ii) to provide assistance to more customers than are currently served; (iii) to lower the energy burden of PSE's HELP participants; and (iv) to collect data necessary to assess program effectiveness and inform ongoing policy discussions.

108. PSE shall provide up to \$2 million through June 30, 2019, for the purpose of covering expenses related to the delivery of the Low-Income Weatherization Program to eligible PSE customers as a one-time contribution in addition to current funding. This will be recovered through Schedule 120. Eligible expenses include the installation of Department of Commerce Weatherization Manual approved cost effective energy efficiency measures, project coordination, health and safety measures, and repairs necessary for the installation of energy efficiency measures.

109. As part of the original decoupling mechanism, PSE agreed to increase its funding for low-income weatherization by \$500,000 per year. The Settling Parties agree to PSE's proposal to continue this higher funding level for the proposed mechanism in this proceeding.

110. PSE shall continue annual \$100,000 shareholder contributions to low-income weatherization, until the next general rate case, consistent with the commitment that PSE made

in the multi-year rate plan approved in Docket UE-121697. This term does not modify any other pre-existing obligation for shareholder funding.

111. The Settling Parties agree to PSE's proposal to modify Schedule 129 to remove Area Median Income from the HELP program Income Eligibility Criteria. On and after the effective date of the tariffs resulting from this proceeding, income eligibility will be based on a household income not exceeding 150 percent of the federal poverty level.

F. Prudence Issues

112. The Settling Parties agree to support a Commission determination in this proceeding that the following projects of PSE are prudent and PSE shall fully recover costs associated with the following projects:

- (i) the Snoqualmie Falls hydroelectric redevelopment project;
- (ii) the acquisition of the Buckley Natural Gas Distribution System;
- (iii) the acquisition and development of the Glacier Battery Storage System;
- (iv) the development and construction of the Ardmore Substation;
- (v) the power purchase agreement with Public Utility District No. 1 Public Utility District No. 1 of Douglas County, Washington to purchase power from the Wells Hydroelectric Project;
- (vi) the acquisition of transmission capacity from Bonneville Power Administration for the (a) the Goldendale Generation Facility (38 MW) and (b) the Mint Farm Generation Facility (15 MW); and
- (vii) the renewal of agreements for transmission capacity from Bonneville Power Administration associated with (a) the Coal Transition Power Purchase Agreement (100 MW), (b) the Mint Farm Generation Facility (20 MW), and (c) purchases from Garrison, Montana (94 MW); and
- (viii) the total amount of actual costs accumulated and deferred until September 30, 2016, associated with PSE's electric and natural gas Environmental Remediation program.

G. Decoupling

113. The Settling Parties agree to Commission Staff's proposal to set the total Allowed Revenue for fixed production costs recovery per decoupled group at the level the Commission authorizes in this general rate proceeding.

114. The Settling Parties agree that all other issues with respect to PSE's revenue decoupling mechanism are not affected by this Settlement and are subject to litigation before the Commission. This includes all other issues regarding the Earnings Sharing Mechanism not otherwise addressed in this Settlement.

H. ERF Issues

115. PSE may file one ERF within one year after the effective date of the tariffs resulting from this proceeding that is consistent with the process and procedures used by the Commission in Dockets UE-130137 & UG-130138 and the parameters identified in Exhibit I to this Settlement. The Settling Parties will support, or not oppose, a schedule for such ERF that would allow rates to take effect within 120 calendar days after filing. Any subsequent ERF or limited rate proceeding filed by PSE shall be consistent with Commission guidance provided by rule or policy statement in Docket A-130355.

I. Colstrip Plant and Transmission System Issues

1. Retirement Account Established Pursuant to Chapter 80.84 RCW

116. PSE shall place \$95 million in hydro-related Treasury Grants into a retirement account established pursuant to RCW 80.04.350 to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 and 2 consistent with Chapter 80.84 RCW.

2. Account Not Established Pursuant to Chapter 80.84 RCW

117. PSE shall place PTCs as they are monetized in a second, more flexible account not established pursuant to Chapter 80.84 RCW. PSE shall use the monetized PTCs in the second account in accordance with the following priority for use: (i) to fund community transition planning funds of \$5 million, as identified in paragraph 118; (ii) to recover unrecovered plant balances for Colstrip Units 1 through 4; and (iii) to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4. The account shall be consistent with the discussion of the account set forth in the Prefiled Rebuttal Testimony of Ms. Katherine J. Barnard, Exh. KJB-17T.

3. Community Transition Planning Process & Funding

118. PSE shall engage in a process with stakeholders to develop a community transition plan, including a funding mechanism, to address the transitioning of PSE's interest in the community of Colstrip, Montana. PSE shall contribute the following amounts to the community transition plan: (i) \$5 million of shareholder dollars and (ii) \$5 million of monetized PTCs. PSE shall place the \$5 million of shareholder dollars in an escrow account (the "Escrow Account") by the end of calendar year 2018. PSE shall place \$5 million of monetized PTCs, when available, from the account established pursuant to paragraph 117 in the Escrow Account. All such funds shall remain in the Escrow Account until such time that there is a community transition plan, including a funding mechanism, in place.

4. Colstrip Reporting Requirements

119. Beginning in 2018, on or before December 1 of each year, PSE shall provide the Commission an annual report containing the following:

- (i) the most recent estimate of the actual retirement date for Colstrip Units 1 and 2 and Colstrip Units 3 and/or 4;

- (ii) In the event of an estimated retirement date earlier than July 1, 2022, for Colstrip Units 1 and 2, and upon the determination by PSE of an estimated retirement date for Colstrip Units 3 and/or 4, a discussion and evaluation of consequences to customers arising from those estimated retirement dates;
- (iii) decommissioning and remediation expenditures associated with Colstrip units since the time of the last report and updated estimates of future costs;
- (iv) an evaluation of the sufficiency of the retirement account established pursuant to Chapter 80.84 RCW to fund and recover decommissioning and remediation activities for Colstrip Units 1 and 2;
- (v) an evaluation of the sufficiency of existing depreciation rates for Colstrip Units 3 and 4 to cover decommissioning and remediation costs for those units; and
- (vi) for years in which PSE issues an Integrated Resource Plan, updated replacement power costs.

5. Colstrip Transmission System Operational Study

120. PSE is working with NorthWestern Energy and the other Colstrip Transmission System owners on the design and staffing of an operational study of transfer capability of the Colstrip Transmission System after Colstrip Units 1 and 2 retire. PSE agrees to work in good faith with the other Colstrip Transmission System owners to have this study completed by June 30, 2018. Upon completion of the study, study results will be submitted to the Commission and interested stakeholders, subject to the consent of the other Colstrip Transmission System owners and subject to disclosure restrictions, such as restrictions on disclosure of Critical Energy Infrastructure Information and non-public transmission information.

6. Colstrip Transmission System Workshop

121. The Settling Parties recommend that the Commission convene one or more workshops, to commence in the first quarter of 2018, to discuss the use of the Colstrip

Transmission System following closure of Colstrip Units 1 and 2, including use by new generation. Commission Staff, the Colstrip Transmission System owners, Path 8 operators, and interested stakeholders will be invited to attend the workshop(s) and to participate in the development of a “Scoping Document” that is intended to (i) identify any known policy or contractual barriers and the technical questions surrounding the use of the Colstrip Transmission System following closure of Colstrip Units 1 and 2, (ii) identify methods, forums, and possible timelines for addressing barriers and technical questions, and (iii) provide information regarding, and promote an understanding of, the applicable processes and procedures, studies, and timelines for addressing these questions, including but not limited to those specified in the Open Access Transmission Tariffs of the Colstrip Transmission System owners for requesting and procuring interconnection to and transmission on the Colstrip Transmission System. The Scoping Document should identify the necessary engineering studies, data, and costs associated with completing the studies, and any other barriers to completing the studies. It is anticipated that PSE will be the primary author of the Scoping Document with input from Commission Staff, the Colstrip Transmission System owners, Path 8 operators, and interested stakeholders. Compliance with the settlement terms does not necessarily include the completion of any additional transmission engineering studies themselves, though the Scoping Document may identify studies that can be completed in the near-term.

7. No Release

122. Nothing in this Settlement shall be construed to operate as a settlement, release or waiver of any and all of PSE’s liabilities for decommissioning and remediation in the State of Montana under Montana or federal law regarding any or all of Colstrip Units 1 through 4.

Nothing in this Settlement shall be construed to operate as expanding or contracting the powers of the State of Montana with respect to any or all of Colstrip Units 1 through 4.

J. Water Heater Rental Program

123. PSE will participate in a collaborative with Commission Staff and other interested stakeholders to discuss the future of the water heater rental programs in PSE's natural gas Schedules 71, 72, and 74.

K. Electric Cost Recovery Mechanism

124. The Settling Parties agree that all issues with respect to PSE's proposed Electric Cost Recovery Mechanism are not affected by this Settlement and are subject to litigation before the Commission.

IV. GENERAL PROVISIONS

125. Entire Agreement. This Settlement is the product of negotiations and compromise amongst the Settling Parties and constitutes the entire agreement of the Settling Parties. Accordingly, the Settling Parties recommend that the Commission adopt and approve the Settlement in its entirety as a full resolution of contested issues in this docket. This Settlement will not be construed against any Settling Party on the basis that it was the drafter of any or all portions of this Settlement. This Settlement supersedes any and all prior oral and written understandings and agreements on such matters that previously existed or occurred in this proceeding, and no such prior understanding or agreement or related representations will be relied upon by the Settling Parties to interpret this Settlement or for any other reason.

126. Confidentiality of Negotiations. The Settling Parties agree that this Settlement represents a compromise in the Settling Parties' positions. As such, conduct, statements and documents disclosed during the negotiation of this Settlement are not admissible in this or any

other proceeding and will remain confidential. Notwithstanding the foregoing, the Settlement itself and its terms do not fall within the scope of this confidentiality provision, and each Settling Party is free to publicly disclose the basis for its own support of the Settlement.

127. Precedential Effect of Settlement. The Settling Parties enter into this Settlement to avoid further expense, uncertainty, inconvenience and delay. The Settling Parties agree that this Settlement Agreement does not serve to bind the Commission when it considers any other matter not specifically resolved by this Settlement in future proceedings. Nothing in this Settlement compels any Settling Party to affirmatively intervene or participate in a future proceeding.

128. Positions Not Conceded. In reaching this Settlement, the Settling Parties agree that no Settling Party concedes any particular argument advanced by that Settling Party or accedes to any particular argument made by any other Settling Party. Nothing in this Settlement (or any testimony, presentation or briefing supporting this Settlement) shall be asserted or deemed to mean that a Settling Party agreed with or adopted another Settling Party's legal or factual assertions in this proceeding. The limitations in this paragraph 128 will not apply to any proceeding to enforce the terms of this Settlement or any Commission order adopting this Settlement in full.

129. Manner of Execution. This Settlement is executed when all Settling Parties sign the Settlement. A designated and authorized representative may sign the Settlement on a Settling Party's behalf. The Settling Parties may execute this Settlement in counterparts. If the Settlement is executed in counterparts, all counterparts shall constitute one agreement. A Settlement signed in counterpart and sent by facsimile or emailed as a pdf is as effective as an original document. A faxed or emailed signature page containing the signature of a Settling Party is acceptable as an original signature page signed by that Settling Party. Each Settling Party shall indicate the date of

its signature on the signature page. The date of execution of the Settlement will be the latest date indicated on the signature page(s).

130. Approval Process and Support of Settlement. Each Settling Party agrees to support in this proceeding the terms and conditions of this Settlement as a full and final resolution of all contested issues between them in the above-captioned docket. Each Settling Party agrees to support or not to oppose the Settlement during the course of whatever proceedings and procedures the Commission determines are appropriate for approval of the Settlement.

131. Commission Approval with Conditions. In the event the Commission approves this Settlement, but with conditions not proposed in this Settlement, the provisions of WAC 480-07-550(2)(b) will apply. The Settling Parties will have ten (10) business days to seek reconsideration and/or file a letter with the Commission accepting or rejecting each such condition. If, in such a timely filed letter, a Settling Party rejects a condition, this Settlement is deemed rejected and void and the Settling Parties will jointly and promptly request the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

132. Commission Rejection. In the event the Commission rejects this Settlement, the provisions of WAC 480-07-550(2)(a) will apply. In that event, the Settling Parties agree to jointly and promptly request the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

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Dated this 15th day of September, 2017.

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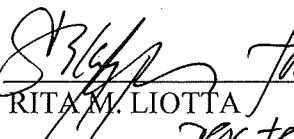
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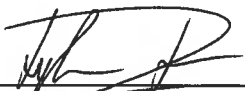
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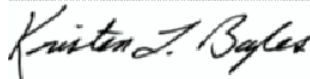
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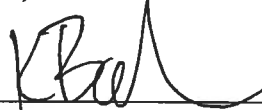
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**Exhibit A to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit A to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Electric Restating and Pro Forma Adjustments

Adjustment (a)	NOI (b)	Rate Base (c)	Revenue Requirement (d) (Note 1)
Actual Results of Operations	\$ 401,002,972	\$ 5,153,204,462	\$ (15,119,001)
Adjustment 13.01-Revenues & Expenses	(29,139,114)	-	47,070,619
Adjustment 13.02-Temperature Normalization	17,527,344	-	(28,313,247)
Adjustment 13.03-Pass-Through Revs. & Exps.	(1,000,540)	-	1,616,249
Adjustment 13.04-Federal Income Tax	(27,023,239)	-	43,652,686
Adjustment 13.05-Tax Benefit of Proforma Interest	54,067,781	-	(87,339,785)
Adjustment 13.06-Depreciation Study	(34,311,788)	(17,155,894)	53,320,227
Adjustment 13.06A-Reg. Asset Colstrip	-	-	-
Adjustment 13.07-Normalize Injuries & Damages	69,387	-	(112,087)
Adjustment 13.08-Bad Debts	681,065	-	(1,100,176)
Adjustment 13.09-Incentive Pay	(109,903)	-	177,535
Adjustment 13.10-D&O Insurance	16,141	-	(26,074)
Adjustment 13.11-Interest on Customer Deposits	(176,606)	-	285,284
Adjustment 13.12-Rate Case Expenses	(264,905)	-	427,920
Adjustment 13.13-Deferred G/L on Property Sales	171,200	-	(276,552)
Adjustment 13.14-Property & Liability Ins	66,147	-	(106,852)
Adjustment 13.15-Pension Plan	(1,184,945)	-	1,914,132
Adjustment 13.16-Wage Increase	(1,357,716)	-	2,193,221
Adjustment 13.17-Investment Plan	(96,705)	-	156,214
Adjustment 13.18-Employee Insurance	(121,751)	-	196,674
Adjustment 13.19-Environmental Remediation	(925,460)	-	1,494,966
Adjustment 13.20-Payment Processing Costs	(2,010,221)	-	3,247,263
Adjustment 13.21-South King Service Center	434,046	15,915,060	1,252,721
Adjustment 13.22-Excise Tax and WUTC Filing Fee	10,262	-	(16,577)
Adjustment 13.23-ISWC and RB Adjustment	-	19,006,090	2,333,350
Adjustment 13.24-Legal Cost Adjustment	-	-	-
Adjustment 13.25-Black Box Adjustment	619,051	-	(1,000,000)
Adjustment 14.01-Power Costs	1,185,175	-	(1,914,503)
Adjustment 14.02-Montana Electric Energy Tax	148,016	-	(239,101)
Adjustment 14.03-Wild Horse Solar	137,890	(1,969,341)	(464,518)
Adjustment 14.04-ASC 815 (Prev. SFAS 133)	(41,672,584)	-	67,316,883
Adjustment 14.05-Storm Damage	(6,137,438)	-	9,914,269
Adjustment 14.06-Reg Assets & Liabilities	1,736,212	(44,085,326)	(8,216,927)
Adjustment 14.07-Glacier Battery Storage	(145,490)	2,842,787	584,026
Adjustment 14.08-Energy Imbalance Market	-	-	-
Adjustment 14.09-Goldendale Capacity Upgrade	2,156	18,140,954	2,223,656
Adjustment 14.10-Mint Farm Capacity Upgrade	-	19,004,590	2,333,166
Adjustment 14.11-White River	(3,288,310)	(4,108,724)	4,807,435
Adjustment 14.12-Reclass of Hydro Treasury Grants	(2,131,857)	5,739,615	4,148,394
Adjustment 14.13-Production Adjustment	32,769	-	(52,934)
Adjusted Results of Operations	326,809,044	5,166,534,272	106,368,556
Changes to Other Price Schedules			(86,208,222)
Overall Electric Revenue Requirement Deficiency			20,160,334

(Note 1) (d) = column (c) x 7.60% rate of return per paragraph 11 of the Settlement less column (b) and the result is divided by the electric conversion factor of .619051 from Exh. MCC-3r at 3.

Exhibit A to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Gas Restating and Pro Forma Adjustments

Adjustment (a)	NOI (b)	Rate Base (c)	Revenue Requirement (d) (Note 1)
Actual Results of Operations	\$ 119,145,769	\$ 1,727,319,760	\$ 19,551,185
Adjustment 11.01-Revenues & Expenses	(32,674,131)	-	52,661,989
Adjustment 11.02-Temperature Normalization	16,046,445	-	(25,862,592)
Adjustment 11.03-Pass-Through Revs. & Exps.	736,148	-	(1,186,474)
Adjustment 11.04-Federal Income Tax	700,822	-	(1,129,538)
Adjustment 11.05-Tax Benefit of Proforma Interest	18,475,298	-	(29,777,255)
Adjustment 11.06-Depreciation Study	13,174,098	6,587,049	(20,426,274)
Adjustment 11.07-Normalize Injuries & Damages	(57,738)	-	93,058
Adjustment 11.08-Bad Debts	35,240	-	(56,797)
Adjustment 11.09-Incentive Pay	104,023	-	(167,657)
Adjustment 11.10-D&O Insurance	11,636	-	(18,754)
Adjustment 11.11-Interest on Customer Deposits	(50,137)	-	80,807
Adjustment 11.12-Rate Case Expenses	(280,617)	-	452,280
Adjustment 11.13-Deferred G/L on Property Sales	(105,090)	-	169,377
Adjustment 11.14-Property & Liability Ins	45,174	-	(72,809)
Adjustment 11.15-Pension Plan	(572,091)	-	922,058
Adjustment 11.16-Wage Increase	(907,409)	-	1,462,502
Adjustment 11.17-Investment Plan	(46,689)	-	75,250
Adjustment 11.18-Employee Insurance	(58,781)	-	94,740
Adjustment 11.19-Environmental Remediation	(5,592,128)	-	9,013,019
Adjustment 11.20-Payment Processing Costs	(1,449,117)	-	2,335,590
Adjustment 11.21-South King Service Center	212,048	7,775,116	610,622
Adjustment 11.22-Excise Tax and WUTC Filing Fee	33,509	-	(54,008)
Adjustment 11.23-ISWC and RB Adjustment		4,743,346	581,021
Adjustment 11.24-Legal Cost Adjustment	-	-	-
Adjustment 11.25-Black Box Adjustment	930,675	-	(1,500,000)
Adjustment 07.01-Gas Cost Recovery Mechanism	(4,003,724)	19,011,708	8,781,713
Adjusted Results of Operations	123,853,234	1,765,436,979	16,633,051
Changes to Other Price Schedules			(52,098,690)
Overall Natural Gas Revenue Requirement Surplus			(35,465,639)

(Note 1) Calculated as column (c) x 7.60% rate of return per paragraph 11 of the Settlement less column (b) and the result is divided by the natural gas conversion factor of .620450 from Exh. MCC-8r at 3.

**Exhibit B to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Electric Depreciation Study Adjustment

LINE				
NO.	DESCRIPTION	TEST YEAR	RESTATED	ADJUSTMENT
1	403 ELEC. DEPRECIATION EXPENSE	\$249,419,038	\$ 306,097,054	\$ 56,678,016
2	403 ELEC. PORTION OF COMMON	15,207,048	13,232,379	(1,974,669)
3	403 DEPR. EXP. ON ASSETS NOT INCLUDED IN STUDY	55,938	55,938	-
4	404 DEPR. EXP. ON ASSETS NOT INCLUDED IN STUDY	29,770,695	29,770,695	-
5	SUBTOTAL DEPRECIATION EXPENSE 403	294,452,719	349,156,066	54,703,348
6				
7	403.1 DEPR. EXP- FAS 143 (RECOVERED IN RATES)	1,352,125	1,729,703	377,578
8	403.1 DEPR. EXP - FAS 143 (NOT RECOVERED IN RATES)	1,476,017	-	(1,476,017)
9	SUBTOTAL DEPRECIATION EXPENSE 403.1	2,828,141	1,729,703	(1,098,438)
10				
11	TOTAL DEPRECIATION EXPENSE	297,280,860	350,885,769	53,604,909
12				
13	AMORTIZATION EXPENSE			
14	411.10 ACCRETION EXP. - ASC 410 (RECOVERED IN RATES)	1,424,661	2,062,091	637,430
15	411.10 ACCRETION EXP. - ASC 410 (NOT RECOVERED IN RATES)	1,148,003	-	(1,148,003)
16	SUBTOTAL ACCRETION EXPENSE 411.10	2,572,664	2,062,091	(510,573)
17				
18	DEPRECIATION EXPENSE 403 ASSOCIATED WITH FLEET	846,819	539,849	(306,970)
19				
20				
21	INCREASE (DECREASE) EXPENSE			52,787,366
22	INCREASE (DECREASE) FIT			(18,475,578)
23	INCREASE (DECREASE) NOI			\$ (34,311,788)
24				
25				
26	ADJUSTMENT TO RATE BASE			
27	ADJUSTMENT TO ACCUM. DEPREC. AT 50% DEPREC. EXP. LINE	50%		\$ (26,393,683)
28	DFIT			9,237,789
29				
30	TOTAL ADJUSTMENT TO RATEBASE			\$ (17,155,894)

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve
and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	ACCURUAL RATE (9)=(8)/(5) (except Colstrip Units 1&2) (NOTE 1)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ELECTRIC PLANT										
STEAM PRODUCTION PLANT										
311.00	STRUCTURES AND IMPROVEMENTS									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	9,209,468	(NOTE 1)	(NOTE 1)	447,725	4.86	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	4,336,957	(NOTE 1)	(NOTE 1)	321,879	7.42	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	90-R2	*	29,664,979	21,454,595	11,176,882	1,012,631	3.41	11.0
	COLSTRIP 4 (NOTE 2)	12-2027	90-R2	*	27,862,835	19,334,081	11,315,037	1,024,406	3.68	11.0
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	30,934,200	(NOTE 1)	(NOTE 1)	806,539	2.61	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	90-R2	*	70,065,641	52,568,884	24,503,321	2,222,796	3.17	11.0
	FREDERICKSON 1/EPCOR	06-2042	90-R2	*	403,636	8,557	415,261	16,597	4.11	25.0
	GOLDENDALE	06-2044	90-R2	*	2,131,452	1,475,544	762,481	28,273	1.33	27.0
	MINT FARM	06-2047	90-R2	*	458,042	117,386	363,559	12,208	2.67	29.8
	SUMAS	06-2033	90-R2	*	1,492,712	1,197,365	369,982	22,408	1.50	16.5
	FERNDALE	06-2034	90-R2	*	571,513	367,246	232,843	13,296	2.33	17.5
TOTAL STRUCTURES AND IMPROVEMENTS										
					177,131,434	96,523,657	49,139,366	5,930,758	3.35	8.3
312.00	BOILER PLANT EQUIPMENT									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	88,145,748	(NOTE 1)	(NOTE 1)	5,451,528	6.18	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	88,368,523	(NOTE 1)	(NOTE 1)	5,914,163	6.69	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	75-S0	*	137,645,882	88,664,395	62,746,075	5,786,628	4.20	10.8
	COLSTRIP 4 (NOTE 2)	12-2027	75-S0	*	126,930,413	74,762,985	64,860,469	5,968,231	4.70	10.9
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	6,043,572	(NOTE 1)	(NOTE 1)	151,538	2.51	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	75-S0	*	15,254,042	10,094,597	6,884,848	622,947	4.08	10.7
	ENCOGEN	06-2033	75-S0	*	42,923,481	34,057,590	11,012,065	689,589	1.61	16.0
	FREDERICKSON 1/EPCOR	06-2042	75-S0	*	18,138,531	7,308,605	11,736,853	489,745	2.70	24.0
	GOLDENDALE	06-2044	75-S0	*	86,173,650	66,841,917	23,640,415	914,220	1.06	25.9
	MINT FARM	06-2047	75-S0	*	26,297,847	3,059,104	24,553,635	860,987	3.27	28.5
	SUMAS	06-2033	75-S0	*	15,704,259	13,938,347	2,551,125	157,672	1.00	16.2
	FERNDALE	06-2034	75-S0	*	44,686,468	30,590,589	16,330,202	947,227	2.12	17.2
TOTAL BOILER PLANT EQUIPMENT										
					696,312,415	329,318,128	224,115,687	27,954,475	4.01	8.0
314.00	TURBOGENERATOR UNITS									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	28,781,740	(NOTE 1)	(NOTE 1)	1,952,444	6.78	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	34,145,119	(NOTE 1)	(NOTE 1)	2,277,281	6.67	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	45-R1.5	*	42,228,337	15,440,101	30,588,786	2,946,524	6.97	10.4
	COLSTRIP 4 (NOTE 2)	12-2027	45-R1.5	*	39,133,170	15,579,409	27,075,747	2,582,499	6.60	10.5
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	3,813,726	(NOTE 1)	(NOTE 1)	105,285	2.76	(NOTE 1)
	ENCOGEN	06-2033	45-R1.5	*	20,710,885	16,987,716	4,759,714	309,829	1.50	15.4
	FREDERICKSON 1/EPCOR	06-2042	45-R1.5	*	15,800,824	6,391,663	10,199,202	452,092	2.86	22.6

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve
and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE
								AMOUNT	RATE	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
315.00	GOLDENDALE	06-2044	45-R1.5	*	89,524,456	69,143,032	24,857,647	1,016,648	1.14	24.5
	MINT FARM	06-2047	45-R1.5	*	24,647,470	6,463,275	19,416,568	728,552	2.96	26.7
	SUMAS	06-2033	45-R1.5	*	22,032,535	17,817,477	5,316,684	336,528	1.53	15.8
	FERNDALÉ	06-2034	45-R1.5	*	18,176,145	11,698,599	7,386,353	439,610	2.42	16.8
	TOTAL TURBOGENERATOR UNITS					159,521,273	129,599,701	13,144,292	3.88	9.9
	ACCESSORY ELECTRIC EQUIPMENT									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	(NOTE 1)	(NOTE 1)	399,892	5.36	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	4,167,725	(NOTE 1)	(NOTE 1)	272,129	6.53	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	60-S2	*	6,789,582	4,484,210	2,894,634	271,489	4.01	10.7
	COLSTRIP 4 (NOTE 2)	12-2027	60-S2	*	6,474,414	3,767,317	3,289,794	304,686	4.71	10.8
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	(NOTE 1)	(NOTE 1)	53,628	2.36	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	60-S2	*	7,639,006	5,452,901	2,873,616	271,079	3.55	10.6
	ENCOGEN	06-2033	60-S2	*	1,678,559	1,328,206	350,353	21,481	1.28	16.3
316.00	FREDERICKSON 1/EPCOR	06-2042	60-S2	*	962,487	358,861	603,625	24,389	2.53	24.7
	GOLDENDALE	06-2044	60-S2	*	7,300,879	5,714,400	1,586,479	59,087	0.81	26.8
	MINT FARM	06-2047	60-S2	*	2,199,936	586,806	1,613,130	54,516	2.48	28.6
	SUMAS	06-2033	60-S2	*	579,011	579,011	91,271	5,491	0.82	16.6
	FERNDALÉ	06-2034	60-S2	*	1,279,531	862,622	416,909	23,581	1.84	17.7
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					23,134,333	13,719,811	1,761,448	3.60	7.8
	MISCELLANEOUS POWER PLANT EQUIPMENT									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	(NOTE 1)	(NOTE 1)	63,866	6.75	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	1,075,704	(NOTE 1)	(NOTE 1)	67,982	6.32	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	50-R1.5	*	1,043,991	378,123	759,827	70,639	6.77	10.8
	COLSTRIP 4 (NOTE 2)	12-2027	50-R1.5	*	1,165,681	420,604	849,988	79,228	6.80	10.7
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	(NOTE 1)	(NOTE 1)	202,687	3.27	(NOTE 1)
	COLSTRIP 1-4 (NOTE 2)	12-2027	50-R1.5	*	251,534	195,027	76,629	7,436	2.96	10.3
	COLSTRIP 3-4 (NOTE 2)	12-2027	50-R1.5	*	4,444,375	2,910,938	1,933,432	185,051	4.16	10.4
	FREDERICKSON 1/EPCOR	06-2042	50-R1.5	*	336,378	138,260	198,118	8,565	2.55	23.1
	GOLDENDALE	06-2044	50-R1.5	*	6,163	4,824	1,339	54	0.88	24.8
	MINT FARM	06-2047	50-R1.5	*	152,757	38,799	113,958	4,168	2.73	27.3
	SUMAS	06-2033	50-R1.5	*	123,691	109,782	13,909	874	0.71	15.9
	FERNDALÉ	06-2034	50-R1.5	*	62,866	43,036	19,830	1,171	1.86	16.9
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					4,239,392	3,967,030	691,721	4.37	5.7
TOTAL STEAM PRODUCTION PLANT					1,277,134,228	612,736,784	420,541,595	49,482,694	3.87	

(NOTE 1) Depreciation Rates for Colstrip Units 1 and 2 were determined separately - see pages 12 and 13 of this Exhibit B for the information used to calculate the depreciation rates for Colstrip Units 1 and 2.

(NOTE 2) Please see paragraph 27 of Settlement Stipulation and Agreement with respect to Colstrip Units 3 and 4.

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE
								ACCRAUAL AMOUNT	ACCRAUAL RATE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)	
HYDROELECTRIC PRODUCTION PLANT										
330.10	EASEMENTS	06-2049	SQUARE	*	0	32,899	11,390	657	2.00	32.7
331.00	STRUCTURES AND IMPROVEMENTS									
	LOWER BAKER	10-2058	75-S1	*	(5)	35,273,454	6,306,966	776,755	2.20	38.6
	UPPER BAKER	10-2058	75-S1	*	(7)	15,612,654	6,565,230	260,751	1.67	38.9
	SNOQUALMIE #1	06-2044	75-S1	*	(2)	58,654,809	5,540,003	54,287,902	3.43	27.0
	SNOQUALMIE #2	06-2044	75-S1	*	(2)	54,612,246	5,903,872	48,800,619	3.36	27.1
	TOTAL STRUCTURES AND IMPROVEMENTS					164,153,163	24,316,071	144,938,591	2.97	29.7
332.00	RESERVOIRS, DAMS AND WATERWAYS									
	LOWER BAKER	10-2058	90-R1.5	*	(9)	115,624,470	22,402,337	103,626,335	2.28	38.3
	UPPER BAKER	10-2058	90-R1.5	*	(12)	119,603,565	59,899,738	74,146,255	1.59	39.0
	SNOQUALMIE #1	06-2044	90-R1.5	*	(4)	53,492,873	4,795,759	50,836,829	3.55	26.8
	SNOQUALMIE #2	06-2044	90-R1.5	*	(4)	60,540,017	4,528,235	58,433,383	3.61	26.8
	TOTAL RESERVOIRS, DAMS AND WATERWAYS					349,260,925	91,536,069	287,044,802	2.47	33.3
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	LOWER BAKER	10-2058	75-S1	*	(6)	41,634,915	9,000,675	893,215	2.15	38.3
	UPPER BAKER	10-2058	75-S1	*	(9)	13,128,271	9,227,178	5,082,637	0.96	40.2
	SNOQUALMIE #1	06-2044	75-S1	*	(2)	36,614,585	3,022,251	34,324,626	3.46	27.1
	SNOQUALMIE #2	06-2044	75-S1	*	(2)	35,031,624	2,768,921	32,963,335	3.49	27.0
	TOTAL WATER WHEELS, TURBINES AND GENERATORS					126,408,394	24,019,025	107,502,932	1.82	26.2
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	LOWER BAKER	10-2058	60-R2.5	*	(3)	15,578,198	2,648,683	13,396,861	2.21	39.0
	UPPER BAKER	10-2058	60-R2.5	*	(4)	2,738,078	1,380,698	1,466,903	1.40	38.2
	SNOQUALMIE #1	06-2044	60-R2.5	*	(1)	16,156,295	1,231,153	15,086,705	3.47	26.9
	SNOQUALMIE #2	06-2044	60-R2.5	*	(1)	11,055,386	725,092	10,440,848	3.51	26.9
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					45,527,958	5,985,626	40,391,317	2.93	30.3
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	LOWER BAKER	10-2058	45-S1	*	(4)	8,012,780	1,065,749	7,267,543	2.70	33.5
	UPPER BAKER	10-2058	45-S1	*	(4)	1,115,022	447,518	712,105	1.97	32.3
	SNOQUALMIE #1	06-2044	45-S1	*	(1)	1,548,649	129,676	1,434,459	3.62	25.6
	SNOQUALMIE #2	06-2044	45-S1	*	(2)	1,592,311	173,199	1,450,938	3.56	25.6
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					12,268,762	1,816,142	10,885,065	2.86	30.9

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**Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve
and Calculated Annual Depreciation Rates as of September 30, 2016**

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE	
								ACCURUAL AMOUNT	ACCURUAL RATE		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)	
335.10	MISCELLANEOUS TOOLS										
	LOWER BAKER	10-2058	18-S4	*	0	846,483	209,088	15,022	1.77	13.9	
	UPPER BAKER	10-2058	18-S4	*	0	597,433	457,056	61,911	10.36	7.4	
	SNOQUALMIE #1	06-2044	18-S4	*	0	674,572	132,337	8,883	1.32	14.9	
	SNOQUALMIE #2	06-2044	18-S4	*	0	80,300	3,035	206	0.26	14.7	
	TOTAL MISCELLANEOUS TOOLS				2,198,788	1,397,272	801,516	86,022	3.91	9.3	
336.00	ROADS, RAILROADS AND BRIDGES										
	LOWER BAKER	10-2058	75-S0.5	*	(1)	1,588,316	188,571	36,505	2.30	38.8	
	UPPER BAKER	10-2058	75-S0.5	*	(2)	2,648,182	2,455,570	66,943	2.53	36.7	
	SNOQUALMIE #1	06-2044	75-S0.5	*	0	637,501	576,649	21,557	3.38	26.7	
	SNOQUALMIE #2	06-2044	75-S0.5	*	0	157,935	142,885	5,341	3.38	26.8	
	TOTAL ROADS, RAILROADS AND BRIDGES				5,031,933	510,048	4,590,731	130,346	2.59	35.2	
	TOTAL HYDROELECTRIC PRODUCTION PLANT				704,883,823	149,591,644	596,176,863	18,909,748	2.68		
OTHER PRODUCTION PLANT											
340.10 341.00	EASEMENTS	06-2030	SQUARE	*	(5)	221,929	197,425	2,589	1.17	13.8	
	STRUCTURES AND IMPROVEMENTS										
	ENCOGEN	06-2033	55-R4	*	(5)	9,238,362	5,850,367	231,822	2.51	16.6	
	FREDERICKSON 1/EPCOR	06-2042	55-R4	*	(5)	5,774,387	3,588,040	142,439	2.47	25.2	
	GOLDENDALE	06-2044	55-R4	*	(5)	34,450,810	26,661,589	348,886	1.01	27.3	
	MINT FARM	06-2047	55-R4	*	(5)	11,003,157	2,980,386	284,891	2.59	30.1	
	SUMAS	06-2033	55-R4	*	(5)	2,897,942	2,321,057	43,243	1.49	16.7	
	CRYSTAL MOUNTAIN	06-2028	55-R4	*	(5)	811,210	372,743	479,027	5.05	11.7	
	FREDONIA	06-2030	55-R4	*	(5)	5,035,527	4,058,711	90,676	1.80	13.5	
	FREDERICKSON	06-2030	55-R4	*	(5)	2,735,279	2,532,962	24,785	0.91	13.7	
	WHITEHORN 2-3	06-2038	55-R4	*	(5)	1,010,183	442,590	28,546	2.83	21.7	
	FERNDAL E	06-2034	55-R4	*	(5)	5,927,075	3,829,889	135,152	2.28	17.7	
		TOTAL STRUCTURES AND IMPROVEMENTS				78,883,932	51,525,360	31,302,768	1,371,375	1.74	22.8
	341.01	STRUCTURES AND IMPROVEMENTS - WIND									
LOWER SNAKE RIVER		06-2037	55-R4	*	(5)	31,416,966	4,583,746	1,373,504	4.37	20.7	
HOPKINS RIDGE		06-2030	55-R4	*	(5)	3,413,472	321,612	234,724	6.88	13.7	
WILD HORSE		06-2031	55-R4	*	(5)	15,120,072	12,672,688	862,193	5.70	14.7	
	TOTAL STRUCTURES AND IMPROVEMENTS - WIND				49,950,510	8,155,248	44,292,788	2,470,421	4.95	17.9	
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES										

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and Calculated Annual Depreciation Rates as of September 30, 2016**

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	ACCURUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
344.00	ENCOGEN	06-2033	45-R3	*	(5)	8,121,641	6,540,475	1,987,248	125,475	1.54
	FREDERICKSON 1/EPCOR	06-2042	45-R3	*	(5)	1,804,663	697,152	1,197,744	50,752	2.81
	GOLDENDALE	06-2044	45-R3	*	(5)	1,887,875	1,477,641	504,628	19,635	1.04
	MINT FARM	06-2047	45-R3	*	(5)	1,457,862	419,775	1,110,980	39,466	2.71
	SUMAS	06-2033	45-R3	*	(5)	3,889,943	3,452,527	631,913	38,673	0.99
	CRYSTAL MOUNTAIN	06-2028	45-R3	*	(5)	476,309	67,263	432,862	37,348	7.84
	FREDONIA	06-2030	45-R3	*	(5)	3,739,992	2,415,322	1,511,669	122,288	3.27
	FREDERICKSON	06-2030	45-R3	*	(5)	3,702,107	3,642,779	244,434	20,693	0.56
	WHITEHORN 2-3	06-2038	45-R3	*	(5)	134,195	138,223	2,681	134	0.10
	FERNDALE	06-2034	45-R3	*	(5)	418,443	286,449	152,916	8,763	2.09
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES						19,137,607	7,777,075	463,227	1.81
	GENERATORS						121,913,369	48,898,682	3,478,023	2.14
344.01	CRYSTAL MOUNTAIN	06-2028	60-R3	*	(5)	575,843	405,829	198,806	17,279	3.00
	FREDONIA	06-2030	60-R3	*	(5)	99,010,603	66,636,896	37,324,236	2,738,639	2.77
	FREDERICKSON	06-2030	60-R3	*	(5)	30,004,025	24,750,966	6,753,260	506,008	1.69
	WHITEHORN 2-3	06-2038	60-R3	*	(5)	33,087,674	30,119,678	4,622,380	216,097	0.65
	TOTAL GENERATORS						162,678,145	48,898,682	3,478,023	2.14
344.01	GENERATORS - WIND						121,913,369	48,898,682	3,478,023	2.14
	LOWER SNAKE RIVER	06-2037	40-R2.5	*	(5)	583,581,425	112,902,903	499,857,593	25,258,090	4.33
	HOPKINS RIDGE	06-2030	40-R2.5	*	(5)	153,525,782	62,513,564	98,688,507	7,495,174	4.88
	WILD HORSE	06-2031	40-R2.5	*	(5)	372,345,403	136,231,904	254,730,769	18,030,523	4.84
	TOTAL GENERATORS - WIND						1,109,452,610	853,276,869	50,783,787	4.58
344.20	GENERATORS - COMBINED CYCLE						56,434,886	3,065,899	540,356	0.73
	ENCOGEN	06-2033	12-L0.5	*	20	74,375,981	1,397,214	19,408,333	2,999,348	11.53
	FREDERICKSON 1/EPCOR	06-2042	12-L0.5	*	20	26,006,935	8,066,153	58,745,266	7,147,793	8.56
	GOLDENDALE	06-2044	12-L0.5	*	20	83,514,274	2,715,654	23,188,396	2,902,863	8.96
	MINT FARM	06-2047	12-L0.5	*	20	32,380,062	20,284,084	2,094,772	267,769	7.8
	SUMAS	06-2033	12-L0.5	*	20	27,973,570	35,341,321	7,547,002	854,758	1.59
	FERNDALE	06-2034	12-L0.5	*	20	53,610,404	124,239,313	114,049,668	14,712,887	4.94
	TOTAL GENERATORS - COMBINED CYCLE						297,861,225	114,049,668	14,712,887	7.8
345.00	ACCESSORY ELECTRIC EQUIPMENT						1,613,490	509,104	33,297	1.65
	ENCOGEN	06-2033	45-S1.5	*	(5)	2,021,518	111,119	200,486	8,075	2.99
	FREDERICKSON 1/EPCOR	06-2042	45-S1.5	*	(5)	296,767	7,420,970	2,520,571	101,965	1.08
	GOLDENDALE	06-2044	45-S1.5	*	(5)	9,468,135	810,921	2,154,249	79,787	2.83
	MINT FARM	06-2047	45-S1.5	*	(5)	2,023,972	3,714,712	897,859	55,659	1.27
	SUMAS	06-2033	45-S1.5	*	(5)	4,392,925				
	ACCESSORY ELECTRIC EQUIPMENT						1,613,490	509,104	33,297	1.65
	ENCOGEN	06-2033	45-S1.5	*	(5)	2,021,518	111,119	200,486	8,075	2.99
	FREDERICKSON 1/EPCOR	06-2042	45-S1.5	*	(5)	296,767	7,420,970	2,520,571	101,965	1.08
	GOLDENDALE	06-2044	45-S1.5	*	(5)	9,468,135	810,921	2,154,249	79,787	2.83
	MINT FARM	06-2047	45-S1.5	*	(5)	2,023,972	3,714,712	897,859	55,659	1.27
	SUMAS	06-2033	45-S1.5	*	(5)	4,392,925				

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FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE
								AMOUNT	RATE	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
345.01	CRYSTAL MOUNTAIN	06-2028	45-S1.5	*	406,680	188,927	236,087	20,822	5.12	11.4
	FREDONIA	06-2030	45-S1.5	*	7,187,908	3,377,315	4,169,989	309,159	4.30	13.5
	FREDERICKSON	06-2030	45-S1.5	*	2,438,637	1,763,155	797,414	59,300	2.43	13.4
	WHITEHORN 2-3	06-2038	45-S1.5	*	201,938	172,085	39,930	2,007	0.99	19.9
	FERNDALE	06-2034	45-S1.5	*	3,321,061	2,410,379	1,286,735	74,292	2.11	17.3
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					21,583,072	12,814,444	745,163	2.27	17.2
	ACCESSORY ELECTRIC EQUIPMENT - WIND									
	LOWER SNAKE RIVER	06-2037	45-S1.5	*	68,432,625	13,311,771	58,542,486	2,921,282	4.27	20.0
	HOPKINS RIDGE	06-2030	45-S1.5	*	13,903,073	5,771,433	8,026,794	665,811	4.79	13.3
346.00	WILD HORSE	06-2031	45-S1.5	*	36,597,248	13,607,937	25,239,173	1,772,155	4.79	14.2
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - WIND					32,691,140	92,608,453	5,359,248	4.49	17.3
	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ENCOGEN	06-2033	45-S1.5	*	792,721	114,831	717,526	45,000	5.68	15.9
	GOLDENDALE	06-2044	45-S1.5	*	2,134,388	1,670,387	570,521	23,079	1.08	24.7
	MINT FARM	06-2047	45-S1.5	*	717,365	200,278	552,956	20,425	2.85	27.1
	SUMAS	06-2033	45-S1.5	*	2,005,074	1,775,642	329,686	20,465	1.02	16.1
	FREDONIA	06-2030	45-S1.5	*	353,338	265,750	105,254	7,885	2.23	13.3
	FREDERICKSON	06-2030	45-S1.5	*	156,088	158,502	5,390	421	0.27	12.8
346.01	WHITEHORN 2-3	06-2038	45-S1.5	*	46,462	28,650	20,136	1,180	2.54	17.1
	FERNDALE	06-2034	45-S1.5	*	665,876	455,832	243,337	14,049	2.11	17.3
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					4,670,072	2,544,806	132,504	1.93	19.2
	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND									
	LOWER SNAKE RIVER	06-2037	50-R2.5	*	2,020,159	548,421	2,412,746	119,799	4.25	20.1
	HOPKINS RIDGE	06-2030	50-R2.5	*	479,165	120,445	382,678	28,324	5.91	13.5
	WILD HORSE	06-2031	50-R2.5	*	706,082	166,936	574,450	39,712	5.62	14.5
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT - WIND					835,801	3,369,874	187,835	4.69	17.9
346.10	MISCELLANEOUS TOOLS									
	ENCOGEN	06-2028	15-L4	*	387,250	108,495	278,755	35,473	9.16	7.9
	FREDERICKSON 1/EPICOR	06-2042	15-L4	*	44,162	12,907	31,255	3,992	9.04	7.8
	GOLDENDALE	06-2044	15-L4	*	469,810	36,213	433,597	46,133	9.82	9.4
	MINT FARM	06-2047	15-L4	*	363,626	61,077	302,549	33,962	9.34	8.9
	SUMAS	06-2033	15-L4	*	310,501	29,326	281,175	30,586	9.85	9.2
	CRYSTAL MOUNTAIN	06-2028	15-L4	*	10,249	2,694	7,555	2,041	19.91	3.7
	FREDONIA	06-2030	15-L4	*	500,057	141,521	358,536	80,315	16.06	4.5
	FREDERICKSON	06-2030	15-L4	*	313,151	63,896	249,315	36,756	12.38	6.4
	WHITEHORN 2-3	06-2038	15-L4	*	252,403	85,235	167,168	27,048	10.72	6.2

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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
TOTAL MISCELLANEOUS TOOLS										
					2,651,210	541,303	2,109,905	298,306	11.25	7.1
346.11	MISCELLANEOUS TOOLS - WIND									
	LOWER SNAKE RIVER	06-2037	15-L4	*	0	124,261	9,773	8,911	7.17	12.8
	HOPKINS RIDGE	06-2030	15-L4	*	0	324,715	95,474	32,087	9.88	7.1
	WILD HORSE	06-2031	15-L4	*	0	333,520	46,846	25,531	7.66	11.2
TOTAL MISCELLANEOUS TOOLS - WIND										
					782,496	152,094	630,402	66,529	8.50	9.5
348.00	ENERGY STORAGE EQUIPMENT		20-S3	0	4,776,732	95,635	4,681,096	238,466	4.99	19.6
TOTAL OTHER PRODUCTION PLANT										
					1,895,861,022	697,385,810	1,210,392,431	80,310,360	4.24	
TRANSMISSION PLANT										
350.10	EASEMENTS		75-R4	0	13,037,871	3,763,178	9,268,693	143,445	1.10	64.6
350.16	EASEMENTS - SUBTRANSMISSION		75-R4	0	2,478,318	(34,424)	2,512,742	34,956	1.41	71.9
350.17	EASEMENTS - HVD RECLASS		75-R4	0	20,438,120	9,201,696	11,236,424	216,465	1.06	51.9
350.99	EASEMENTS - GIF		75-R4	0	172,389	39,559	132,830	2,066	1.20	64.3
352.00	STRUCTURES AND IMPROVEMENTS		65-R4	(5)	3,818,788	1,232,451	2,777,276	58,188	1.52	47.7
352.60	STRUCTURES AND IMPROVEMENTS - SUBTRANSMISSION		65-R4	(5)	1,759,634	68,052	1,779,564	28,096	1.60	63.3
352.70	STRUCTURES AND IMPROVEMENTS - HVD RECLASS		65-R4	(5)	2,270,219	1,182,926	1,200,804	29,883	1.32	40.2
352.90	STRUCTURES AND IMPROVEMENTS - GIF		65-R4	(5)	1,956,304	298,138	1,755,981	29,470	1.51	59.6
353.00	STATION EQUIPMENT		45-R1.5	(10)	157,933,119	45,791,174	127,935,257	3,642,533	2.31	35.1
353.60	STATION EQUIPMENT - SUBTRANSMISSION		45-R1.5	(10)	108,797,057	6,534,012	113,142,750	2,669,975	2.45	42.4
353.70	STATION EQUIPMENT - HVD RECLASS		45-R1.5	(10)	198,771,432	67,306,052	151,342,523	4,951,422	2.49	30.6
353.80	STATION EQUIPMENT - LIF		45-R1.5	(10)	405,246	193,972	251,799	9,978	2.46	25.2
353.90	STATION EQUIPMENT - GIF		45-R1.5	(10)	129,588,729	38,323,242	104,202,360	2,697,721	2.08	38.6
354.00	TOWERS AND FIXTURES		75-R4	(15)	90,563,276	43,514,475	60,633,293	1,136,178	1.25	53.4
354.70	TOWERS AND FIXTURES - HVD RECLASS		75-R4	(15)	1,307,253	896,631	836,709	16,945	1.12	48.4
354.90	TOWERS AND FIXTURES - GIF		75-R4	(15)	133,399	110,351	43,038	609	0.46	70.7
355.00	POLES AND FIXTURES		43-R1	(40)	85,130,848	27,928,206	91,254,981	2,587,052	3.04	35.3
355.60	POLES AND FIXTURES - SUBTRANSMISSION		43-R1	(40)	78,708,415	4,825,666	105,366,116	2,559,412	3.25	41.2
355.70	POLES AND FIXTURES - HVD RECLASS		43-R1	(40)	170,738,424	47,576,643	191,457,151	5,810,001	3.40	33.0
355.90	POLES AND FIXTURES - GIF		43-R1	(40)	8,879,281	2,097,318	10,333,675	274,655	3.09	37.6
356.00	OVERHEAD CONDUCTORS AND DEVICES		60-R2.5	(10)	127,496,955	69,844,695	70,401,955	1,643,066	1.29	42.8
356.60	OVERHEAD CONDUCTORS AND DEVICES - SUBTRANSMISSION		60-R2.5	(10)	25,127,106	1,384,144	26,355,673	455,609	1.81	57.6
356.70	OVERHEAD CONDUCTORS AND DEVICES - HVD RECLASS		60-R2.5	(10)	132,747,969	70,324,578	75,698,188	1,748,446	1.31	43.4
356.90	OVERHEAD CONDUCTORS AND DEVICES - GIF		60-R2.5	(10)	6,289,538	1,610,720	5,285,772	100,331	1.60	52.7
357.70	UNDERGROUND CONDUIT - HVD RECLASS		55-R4	0	700,575	375,467	17,834	2,55	1.73	18.2
357.90	UNDERGROUND CONDUIT - GIF		55-R4	0	510,284	114,486	395,799	8,039	1.73	44.8
358.70	UNDERGROUND CONDUCTORS AND DEVICES - HVD RECLASS		55-R4	0	2,932,873	2,515,857	417,016	21,673	0.74	19.2

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE
								AMOUNT	RATE	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
358.00	UNDERGROUND CONDUCTORS AND DEVICES - GIF	55-R4	0	0	34,023,857	8,177,268	25,846,588	527,144	1.55	49.0
359.00	ROADS AND TRAILS	65-R4	0	0	1,379,629	397,494	982,136	19,310	1.40	50.9
359.70	ROADS AND TRAILS - HVD RECLASS	65-R4	0	0	568,185	279,529	288,657	9,535	1.68	30.3
359.99	ROADS AND TRAILS - GIF	65-R4	0	0	8,021	3,313	4,708	117	1.46	40.2
	TOTAL TRANSMISSION PLANT				1,408,833,111	455,882,866	1,193,365,586	31,445,954	2.23	
DISTRIBUTION PLANT										
360.10	EASEMENTS	65-R4	0	0	6,192,998	3,154,464	3,038,534	69,962	1.13	43.4
361.00	STRUCTURES AND IMPROVEMENTS	60-R2	(10)	(10)	7,980,827	2,327,041	6,451,869	140,499	1.76	45.9
362.00	STATION EQUIPMENT	52-S0	(15)	(15)	434,912,649	125,213,289	374,936,256	8,871,422	2.04	42.3
363.00	BATTERY STORAGE EQUIPMENT	20-S3	0	0	1,194,183	23,909	1,170,274	59,617	4.99	19.6
364.00	POLES, TOWERS AND FIXTURES	46-R1.5	(50)	(50)	340,904,415	146,427,147	364,929,476	10,713,901	3.14	34.1
365.00	OVERHEAD CONDUCTORS AND DEVICES	38-R2.5	(25)	(25)	409,216,187	120,401,105	391,119,128	15,306,553	3.74	25.6
366.00	UNDERGROUND CONDUIT	55-R3	(10)	(10)	672,272,623	261,027,349	478,472,536	11,912,719	1.77	40.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES	38-R2.5	(40)	(40)	844,856,752	341,308,280	841,491,174	33,220,993	3.93	25.3
368.00	LINE TRANSFORMERS	44-R2	(50)	(50)	462,673,681	181,111,939	512,898,561	18,805,777	4.06	27.3
369.00	SERVICES	55-R3	(60)	(60)	182,057,677	116,569,686	174,722,597	5,727,599	3.15	30.5
370.00	METERS	20-L1	(10)	(10)	140,665,914	34,679,835	120,032,670	11,730,432	8.34 *	10.2
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	31-S0.5	(15)	(15)	53,727,968	18,793,323	42,593,840	2,552,518	4.75	16.8
	TOTAL DISTRIBUTION PLANT				3,556,655,873	1,351,037,388	3,312,276,915	119,111,992	3.35	
GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS	06-2057	75-S1.5	*	20,916,098	7,596,119	14,365,784	374,164	1.79	38.4
	SKAGIT		45-S1.5	(5)	27,691,075	20,042,691	9,032,937	261,922	0.95	34.5
	OTHER STRUCTURES									
	TOTAL STRUCTURES AND IMPROVEMENTS				48,607,173	27,638,810	23,398,721	636,086	1.43	36.6
391.10	OFFICE FURNITURE AND EQUIPMENT									
	FULLY ACCRUED			0	5,896,620	5,896,620	0	0	-	-
	AMORTIZED		20-SQ	0	4,398,911	2,177,000	2,221,911	219,874	5.00	10.1
	TOTAL OFFICE FURNITURE AND EQUIPMENT				10,295,531	8,073,620	2,221,911	219,874	2.14	10.5
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		5-SQ	0	22,169,282	13,532,000	8,637,282	4,433,881	20.00	1.9
392.00	TRANSPORTATION EQUIPMENT		12-L3	10	9,188,876	5,273,638	2,996,351	482,333	5.25	6.2

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Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve
and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL		COMPOSITE REMAINING LIFE
								ACCURUAL AMOUNT	ACCURUAL RATE	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
393.00	STORES EQUIPMENT FULLY ACCRUED AMORTIZED		FULLY ACCRUED 20-SQ	0 0	589,596 170,969	589,596 33,600	0 137,369	0 8,552	- 5.00	- 16.1
	TOTAL STORES EQUIPMENT									
					760,565	623,196	137,369	8,552	0.99	16.4
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT FULLY ACCRUED AMORTIZED		FULLY ACCRUED 20-SQ	0 0	3,661,295 8,917,578	3,661,295 2,134,000	0 6,783,578	0 445,520	- 5.00	- 15.2
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT									
					12,578,873	5,795,295	6,783,578	445,520	3.61	15.7
395.00	LABORATORY EQUIPMENT FULLY ACCRUED AMORTIZED		FULLY ACCRUED 20-SQ	0 0	4,155,876 7,875,250	4,155,876 3,991,000	0 3,884,250	0 393,582	- 5.00	- 9.9
	TOTAL LABORATORY EQUIPMENT									
					12,031,127	8,146,876	3,884,250	393,582	3.40	10.5
396.00	POWER OPERATED EQUIPMENT		14-L3	10	6,082,762	2,469,391	3,005,095	400,413	6.58	7.5
397.00	COMMUNICATION EQUIPMENT FULLY ACCRUED AMORTIZED		FULLY ACCRUED 15-SQ	0 0	12,913,083 80,874,473	12,913,083 28,500,000	0 52,374,473	0 5,396,167	- 6.67	- 9.7
	TOTAL COMMUNICATION EQUIPMENT									
					93,787,556	41,413,083	52,374,473	5,396,167	5.81	10.3
398.00	MISCELLANEOUS EQUIPMENT FULLY ACCRUED AMORTIZED		FULLY ACCRUED 15-SQ	0 0	86,544 190,786	86,544 67,100	0 123,686	0 12,718	- 6.67	- 9.7
	TOTAL MISCELLANEOUS EQUIPMENT									
					277,330	153,644	123,686	12,718	4.47	10.3
TOTAL GENERAL PLANT					215,779,075	113,119,553	103,562,716	12,429,126	5.76	
UNRECOVERED RESERVE TO BE AMORTIZED										
391.10	OFFICE FURNITURE AND EQUIPMENT					(1,913,644)		382,729	***	
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS					20,333		(4,067)	***	
393.00	STORES EQUIPMENT					(384,429)		76,886	***	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(798,799)		159,760	***	
395.00	LABORATORY EQUIPMENT					(3,153,918)		630,784	***	
397.00	COMMUNICATION EQUIPMENT					(7,646,069)		1,529,214	***	
398.00	MISCELLANEOUS EQUIPMENT					(63,957)		12,791	***	

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Docket Nos. UE-170033 and UG-170034
Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF SEPTEMBER 30, 2016 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	COMPOSITE REMAINING LIFE (10)-(7)/(8)
	TOTAL UNRECOVERED RESERVE TO BE AMORTIZED								
						(13,940,483)		2,788,097	
	TOTAL DEPRECIABLE PLANT								
					9,059,147,131	3,365,813,561	6,844,316,106	314,477,971	
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
301.00	ORGANIZATION				114,202				
302.00	FRANCHISES AND CONSENTS				55,290,806	10,926,343			
303.00	MISCELLANEOUS INTANGIBLES				64,531,940	23,833,179			
310.00	LAND AND LAND RIGHTS				3,795,193				
317.00	ARO				252,964	71,227			
317.10	ARO				35,282,326	2,724,424			
330.00	LAND AND LAND RIGHTS				6,106,995				
337.00	ARO				-				
340.00	LAND AND LAND RIGHTS				15,794,832				
347.00	ARO				35,764,903	3,237,154			
350.00	LAND AND LAND RIGHTS				3,261,663				
350.70	LAND AND LAND RIGHTS				11,102,367				
350.90	LAND AND LAND RIGHTS				1,908				
359.90	ARO				5,387,662	84,806			
360.00	LAND AND LAND RIGHTS				31,113,741	9			
374.00	ARO				2,696,910	315,002			
389.00	LAND AND LAND RIGHTS				5,316,208				
390.10	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS				184,776	170,844			
	TOTAL NONDEPRECIABLE PLANT								
					275,999,394	41,362,988			
	TOTAL ELECTRIC PLANT								
					9,335,146,525	3,407,176,548	6,844,316,106	314,477,971	

* LIFE SPAN PROCEDURE USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

** FOR NEW ADDITIONS FOR AMI METERS, THE RECOMMENDATION IS A 20-S2.5 SURVIVOR CURVE, (10) NET SALVAGE AND A 5.50% DEPRECIATION RATE.

*** 5-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO AMORTIZATION ACCOUNTING.

NOTE: FOR NEW ASSETS FOR THE COMPANY'S EQUIPMENT LEASE PROGRAM, THE FOLLOWING ESTIMATES AND DEPRECIATION RATES ARE RECOMMENDED:

	LIFE	NET SALVAGE	RATE
RESIDENTIAL HEAT PUMPS	18-S3	0	5.56
RESIDENTIAL WATER HEATERS	15-L3	0	6.67
COMMERCIAL WATER HEATERS	10-L3	0	10.00

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Depreciation Rates for Colstrip Units 1 and 2

Summary of Estimated Survivor Curves, Original Cost, Book Reserve, Theoretical Reserve and
Whole Life Depreciation Accruals and Rates as of September 30, 2016

	ACCOUNT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	THEORETICAL RESERVE	THEORETICAL RESERVE		WHOLE LIFE ANNUAL ACCRUAL RATE
					IMBALANCE AMOUNT	AMOUNT	
(1)	(2)	(3)	(4)	(5)=(3)-(4)	(6)	(7)	
ELECTRIC PLANT							
STEAM PRODUCTION PLANT							
311.00	STRUCTURES AND IMPROVEMENTS						
	COLSTRIP 1	9,209,467.84	5,369,108	6,652,518	(1,283,410)	447,725	4.86
	COLSTRIP 2	4,336,957.28	1,063,479	2,494,123	(1,430,644)	321,879	7.42
	COLSTRIP 1-2	30,934,199.88	26,913,191	26,335,450	577,741	808,539	2.61
	TOTAL STRUCTURES AND IMPROVEMENTS	44,480,625.00	33,345,777	35,482,091	(2,136,314)	1,578,143	3.55
312.00	BOILER PLANT EQUIPMENT						
	COLSTRIP 1	88,145,747.64	42,279,305	57,146,892	(14,867,587)	5,451,528	6.18
	COLSTRIP 2	88,368,523.22	36,998,692	54,704,019	(17,705,328)	5,914,163	6.69
	COLSTRIP 1-2	6,043,572.10	5,184,007	5,195,394	(11,387)	151,538	2.51
	TOTAL BOILER PLANT EQUIPMENT	182,557,842.96	84,462,004	117,046,305	(32,584,301)	11,517,229	6.31
314.00	TURBOGENERATOR UNITS						
	COLSTRIP 1	28,781,740.46	9,901,631	17,820,709	(7,919,078)	1,952,444	6.78
	COLSTRIP 2	34,145,118.66	12,039,663	21,361,548	(9,321,885)	2,277,281	6.67
	COLSTRIP 1-2	3,813,725.50	3,575,882	3,255,399	320,483	105,285	2.76
	TOTAL TURBOGENERATOR UNITS	66,740,584.62	25,517,176	42,437,656	(16,920,480)	4,335,010	6.5
315.00	ACCESSORY ELECTRIC EQUIPMENT						
	COLSTRIP 1	7,465,362.62	4,686,400	5,200,491	(514,091)	399,892	5.36
	COLSTRIP 2	4,167,725.42	1,460,588	2,615,195	(1,154,607)	272,129	6.53
	COLSTRIP 1-2	2,272,860.64	1,998,202	1,978,529	19,673	53,628	2.36
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	13,905,948.68	8,145,190	9,794,215	(1,649,025)	725,649	5.22

Exhibit B to the Multiparty Settlement Stipulation and Agreement
Docket Nos. UE-170033 and UG-170034
Approved Depreciation Rates for Colstrip Units 1 and 2

Summary of Estimated Survivor Curves, Original Cost, Book Reserve, Theoretical Reserve and
Whole Life Depreciation Accruals and Rates as of September 30, 2016

(1) ACCOUNT	(2) ORIGINAL COST AS OF SEPTEMBER 30, 2016	(3) BOOK DEPRECIATION RESERVE	(4) THEORETICAL RESERVE	THEORETICAL RESERVE		(6) WHOLE LIFE ANNUAL ACCRU- AMOUNT	(7) RATE
				IMBALANCE AMOUNT	(5)=(3)-(4)		
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT							
COLSTRIP 1	946,611.59	373,569	585,561	(211,992)		63,866	6.75
COLSTRIP 2	1,075,704.32	483,996	692,357	(208,361)		67,982	6.32
COLSTRIP 1-2	6,205,596.72	5,331,195	5,084,569	246,626		202,687	3.27
TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT	8,227,912.63	6,188,760	6,362,487	(173,727)		334,535	4.07
TOTAL STEAM PRODUCTION PLANT	315,912,913.89	157,658,907	211,122,754	(53,463,847)		18,490,566	5.85
TOTAL ELECTRIC PLANT	315,912,913.89	157,658,907	211,122,754	(53,463,847)		18,490,566	5.85

**Exhibit C to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit C to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Adjustment to Investor-Supplied Working Capital and Rate Base (ISWC)

For the Twelve Months Ended September 30, 2016

LINE (a) NO. Description	PSE WP - "5.03 E&G RB - 5.04 E&G WC 17GRC.xlsx" (b) AMA	ADJUSTMENT (c) = (d) - (b) AMA	FINAL WORKING CAPITAL (d) AMA
1 AVERAGE INVESTED CAPITAL			
2 Total Average Invested Capital	7,389,220,147	(0)	7,389,220,147
3			
4 INVESTMENTS			
5			
6 Electric (Rate Base and Deferrals)			
7			
8 Total Electric (Rate Base and Deferrals)	4,961,861,442	(35,662,222)	4,926,199,220
9			
10 Gas (Rate Base and Deferrals)			
11			
12 Total Gas (Rate Base and Deferrals)	1,697,061,852	(47,382,699)	1,649,679,153
13			
14 Total Electric & Gas Investment	6,658,923,294	(83,044,921)	6,575,878,373
15			
16			
17 Non-Operating			
18			
19 Total Non Operating Investment	425,115,043	36,765,423	461,880,466
20			
21 Total Average Investments	7,084,038,337	(46,279,499)	7,037,758,839
22 Rounding			
23 Total Investor Supplied Capital	\$ 305,181,810	\$ 46,279,499	\$ 351,461,308
24			
25			
26 INVESTED SUPPLIED WORKING CAPITAL			
27			
28 Electric Working Capital	\$ 227,005,242	19,006,090	\$ 246,011,332
29 Electric Allocation (Line 28 / Line 23)	74.38%		70.00%
30 Gas Working Capital	\$ 77,640,607	4,743,346	\$ 82,383,953
31 Gas Allocation (Line 30 / Line 23)	25.44%		23.44%
32 Non Operating Working Capital	\$ 535,961	22,530,063	\$ 23,066,024
33 Non-Operating Allocation (Line 32 / Line 23)	0.18%		6.56%

**Exhibit D to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit D to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
CAISO Energy Imbalance Market Costs

Description	Reference	Annual in Sch B	Monthly in Sch B
557 Costs	Exhibit PKW-22C	\$ 2,333	\$ 194.4
Plant Related Depreciation and Return	(a)	6,126	510.5
Amount to be included in Adjustment Section of Schedule B		<u>\$ 8,459</u>	<u>\$ 704.9</u>

Line	(a) EIM Plant Related Costs		Reference
1			
2	Cost of Debt	2.99%	KJB-18.02
3	ROR per Settlement	7.60%	Settlement
4	Rate Year EIM Rate Base	\$5,132	KJB-21.08
5	Variable Prod Factor	0.961606	KJB-18.03
6			
7	NOI of Plant Costs in KJB	(\$3,493)	KJB-21.08
8	Tax Benefit of Proforma Interest	54	Line 2 x 4 x 35%
9	Return on Rate Base	(390)	Line 3 x 4
10	Total Rate Base Related Costs	<u>\$3,829</u>	
11	Pre-tax	5,891	Line 10 ÷ 65%
12	Pre-Production Factored Plant Related Cost	(a) ==> \$6,126	Line 11 ÷ Line 5
13			

**Exhibit E to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit E to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Power Cost Adjustment

For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1	PRODUCTION EXPENSES:			
2	501-STEAM FUEL	\$ 85,246,015	\$ 69,962,949	\$ (15,283,065)
3	547-FUEL	149,756,872	171,115,374	21,358,502
4	555-PURCHASED POWER	523,037,996	378,349,380	(144,688,616)
5	557-OTHER POWER EXPENSE	9,308,464	7,410,673	(1,897,791)
6	565-WHEELING	113,800,193	108,374,278	(5,425,915)
7	447-SALES FOR RESALE	(201,125,742)	(36,228,867)	164,896,875
8	456-PURCHASES/SALES OF NON-CORE GAS	18,023,678	(16,223,873)	(34,247,551)
9	PRODUCTION O&M	125,897,437	137,871,323	11,973,886
10	TRANS. EXP. INCL. 500KV O&M	662,135	662,135	-
11	456-1 VARIABLE TRANSM. INCOME - COLSTRIP, E	(8,228,549)	(11,639,833)	(3,411,285)
12	EQUITY RETURN ON CENTRALIA TRANSITION COAL PPA		4,769,481	4,769,481
13	INCREASE (DECREASE) EXPENSE	816,378,499	814,423,019	(1,955,479)
14				
15	INCREASE (DECREASE) OPERATING INCOME	(816,378,499)	(814,423,019)	1,955,479
16				
17	STATE UTILITY TAX SAVINGS FOR LINE 12	3.873%		(132,133)
18	INCREASE (DECREASE) INCOME			1,823,347
19	INCREASE (DECREASE) FIT @	35%		638,171
20	INCREASE (DECREASE) NOI			\$ 1,185,175

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Power Cost Bridge

For the Twelve Months Ended September 30, 2016

	FERC	F/V	a	b	c	12MOE SAP 9/30/2016	ETIF Reported in FERC	Remove Benefits	Remove Payroll Tax	Net Test Year	12MOE 12/31/2018	Reclass Ben & Tax	Factor		Complement
													Fixed PF 0.000%	Variable PF 3.839%	
1															Fixed PF 0.000%
2															Variable PF 0.961606000
3															
4															
5															
6															
7															
8															
9															
10	501	V		Steam Fuel		\$ 85,246,015	\$ -	\$ -	\$ -	\$ 85,246,015	\$ 72,756,357	\$ -	\$ 72,756,357	\$ 69,962,949	
11	547	V		GFG Fuel		149,756,872				149,756,872	177,947,490		177,947,490	171,115,374	
12	555	V		Purchased Power		375,700,425	147,337,571			523,037,996	393,455,718		393,455,718	378,349,380	
13	557	F		Other Power Expense		10,715,288		(1,364,051)	(368,616)	8,982,621	8,830,007	(1,732,667)	7,097,341	7,097,341	
14	557	V		Brokerage Fees		325,842				325,842	325,842		325,842	313,332	
15	565	V		Wheeling		113,800,193				113,800,193	112,701,333		112,701,333	108,374,278	
16	447	V		Sales for Resale		(53,788,171)	(147,337,571)			(201,125,742)	(37,675,375)		(37,675,375)	(36,228,867)	
17	456	V		Purchases/(Sales) of Non-Core Gase		18,023,678				18,023,678	(16,871,643)		(16,871,643)	(16,223,873)	
18	Net power costs from TY Margin or RY DEM Exh					695,780,142	-	(1,364,051)	(368,616)	698,047,475	711,469,730	(1,732,667)	709,737,064	682,759,914	
19															
20	various	F		Production O&M		133,910,147		(6,304,989)	(1,707,721)	125,897,437	145,884,033	(8,012,710)	137,871,323	137,871,323	
21	various	F		500KV Trans Exp/O&M		662,135				662,135	662,135		662,135	662,135	
22	456-17	F		OATT Transmission Revenue		(8,228,549)			(8,228,549)		(11,639,833)		(11,639,833)	(11,639,833)	
23	n/a	V		Equity Return on Centralia Coal Transition PPA						-	4,959,912		4,959,912	4,769,481	
24	Total Power Cost Adjustment					\$ 826,123,875	\$ -	\$ (7,669,040)	\$ (2,076,336)	\$ 816,378,499	\$ 851,335,976	\$ (9,745,377)	\$ 841,590,600	\$ 814,423,019	

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Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Settlement Power Costs Projections - AURORA + Not in Models

Rate Year January 2018 through December 2018

Gas Price date: June 23, 2017
(dollars are in thousands)

2017 GRC Settlement - Prices at June 23, 2017

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	17GRC Settlement	17GRC Rebutal	Change
501 Coal Fuel	\$ 7,667	\$ 7,191	\$ 7,080	\$ 4,766	\$ 3,346	\$ 3,126	\$ 6,281	\$ 6,821	\$ 6,270	\$ 6,376	\$ 6,546	\$ 7,286	\$ 72,756	\$ 72,991	\$ (234)
547 Natural Gas Fuel	\$ 18,771	\$ 19,557	\$ 15,194	\$ 9,556	\$ 5,590	\$ 7,523	\$ 13,985	\$ 17,825	\$ 17,035	\$ 16,964	\$ 17,158	\$ 18,790	\$ 177,947	\$ 153,808	\$ 24,139
555 Purchase & Interchang	\$ 43,000	\$ 34,643	\$ 36,005	\$ 32,074	\$ 32,646	\$ 27,718	\$ 24,622	\$ 20,857	\$ 24,146	\$ 28,289	\$ 37,953	\$ 51,503	\$ 393,456	\$ 418,488	\$ (25,032)
557 Other Power Supply	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 9,156	\$ 11,489	\$ (2,333)
565 Wheeling	\$ 9,559	\$ 9,610	\$ 9,696	\$ 9,545	\$ 9,484	\$ 9,255	\$ 9,177	\$ 9,228	\$ 9,151	\$ 9,230	\$ 9,322	\$ 9,444	\$ 112,701	\$ 112,629	\$ 73
447 Secondary Sales	\$ (2,117)	\$ (4,041)	\$ (1,802)	\$ (1,601)	\$ (1,445)	\$ (1,758)	\$ (7,431)	\$ (8,449)	\$ (6,243)	\$ (2,117)	\$ (584)	\$ (87)	\$ (37,675)	\$ (37,644)	\$ (32)
456 Non-Core Gas	\$ (2,712)	\$ (2,132)	\$ (1,362)	\$ (740)	\$ (549)	\$ (523)	\$ (1,026)	\$ (853)	\$ (947)	\$ (1,482)	\$ (1,664)	\$ (2,880)	\$ (16,872)	\$ (16,904)	\$ 32
Total Power Costs	\$ 74,932	\$ 65,591	\$ 65,573	\$ 54,363	\$ 49,836	\$ 46,104	\$ 46,371	\$ 46,191	\$ 50,175	\$ 58,023	\$ 69,492	\$ 84,819	\$ 711,470	\$ 714,857	\$ (3,387)
Load in MWh	2,347,334	2,023,152	2,120,831	1,849,726	1,709,643	1,653,015	1,717,662	1,730,905	1,672,253	1,858,747	2,085,376	2,503,903	23,272,547	23,272,547	-

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production O&M

For the Twelve Months Ended September 30, 2016

			Settlement: Adjusted Wind	Rebuttal	Change from Rebuttal
	Test Year 10/01/2015 - 09/30/2016	Adjustments	2017 GRC Jan - Dec 2018	2017 GRC Jan - Dec 2018	2017 GRC Update vs. Update w/ revised Wx
Resources					
Colstrip 1/2	23,127,394	3,088,660	26,216,054	26,216,054	-
Colstrip 3/4	16,143,246	2,073,771	18,217,016	18,217,016	-
Lower Baker	4,763,084	-	4,763,084	4,763,084	-
Upper Baker	4,413,567	-	4,413,567	4,413,567	-
Baker License	2,499,722	-	2,499,722	2,499,722	-
Electron	10,335	(10,335)	-	-	-
Snoqualmie 1/2	5,169,224	-	5,169,224	5,169,224	-
Snoqualmie License	403,706	-	403,706	403,706	-
Hopkins Ridge	6,507,378	254,159	6,761,537	6,572,112	189,426
Wild Horse	10,879,887	375,984	11,255,871	11,136,003	119,868
Wild Horse Expansion	1,278,119	(142,219)	1,135,900	1,132,441	3,460
Lower Snake River	12,395,839	2,656,948	15,052,788	14,893,042	159,746
Crystal	149,181	-	149,181	149,181	-
Encogen	4,456,797	1,653,961	6,110,758	6,110,758	-
Ferndale	6,079,604	320,966	6,400,569	6,400,569	-
Freddie 1	4,137,387	1,078,811	5,216,199	5,216,199	-
Frederickson	2,149,800	187,572	2,337,372	2,337,372	-
Fredonia 1-4	3,508,973	-	3,508,973	3,508,973	-
Goldendale	8,641,557	(445,719)	8,195,838	8,195,838	-
Mint Farm	7,904,641	(184,794)	7,719,847	7,719,847	-
Sumas	4,726,636	695,333	5,421,970	5,421,970	-
Whitehorn 1-4	1,620,957	370,788	1,991,745	1,991,745	-
Sys Control & Dispatch	31,426	-	31,426	31,426	-
Undistrib/Other Including Incentive	2,911,685	-	2,911,685	2,911,685	-
Clearing, Compliance					
Centralia	-	-	-	-	-
Prod. O&M incl. Benefits/Taxes	133,910,147	11,973,886	145,884,033	145,411,533	472,499

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Montana Electric Energy Tax Adjustment
For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION	PROFORMA	AMOUNT
1	RATE YEAR KWH	3,833,803,119	
2	TRANSMISSION LINE LOSS % FOR WECC	5.0%	
3	WETT TAX RATE	0.00015	
4	WETT Tax	\$	546,317
5			
6	EEELT TAX RATE	0.0002	
7	EEELT Tax	\$	766,761
8			
9	RESTATE ENERGY TAX (LINE 1 X LINE 2)		#####
10	CHARGED TO EXPENSE		1,540,793
11	INCREASE (DECREASE) INCOME		227,716
12			
13	INCREASE (DECREASE) FIT @ 35%		79,700
14	INCREASE (DECREASE) NOI		\$ 148,016

**Exhibit F to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit F to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Storm Adjustment

For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION	AMOUNT		
NORMAL STORMS				
1		Transmission	Distribution	Total
2	ACTUAL O&M:			
3	TWELVE MONTHS ENDED 09/30/11	146,578	9,324,413	9,470,991
4	TWELVE MONTHS ENDED 09/30/12	330,554	11,614,288	11,944,841
5	TWELVE MONTHS ENDED 09/30/13	115,489	5,128,915	5,244,404
6	TWELVE MONTHS ENDED 09/30/14	427,808	12,676,576	13,104,384
7	TWELVE MONTHS ENDED 09/30/15	718,706	12,394,592	13,113,298
8	TWELVE MONTHS ENDED 09/30/16	506,069	10,553,488	11,059,557
9	TOTAL NORMAL STORMS	2,245,204	61,692,271	63,937,475
10				
11	SIX-YEAR AVERAGE STORM EXPENSE FOR RATE YEAR (LINE 9 ÷ 6 YEAF	374,201	10,282,045	10,656,246
12				
13	CHARGED TO EXPENSE 12 MONTH ENDED 09/30/16			
14	STORM DAMAGE EXPENSE (LINE 8)	506,069	10,553,488	11,059,557
15				
16	INCREASE (DECREASE) OPERATING EXPENSE (LINE 11-LINE 14)	(131,868)	(271,443)	(403,311)
CATASTROPHIC STORMS				
19	DEFERRED BALANCES FOR UE-090704 4 YEAR AMORTIZATION			
20	AT START OF RATE YEAR (01/31/2018):			
21	2010 STORM DAMAGE	-		
22	2010 STORM DAMAGE PENDING APPROVAL	50,186		
23	2014 STORM DAMAGE-PENDING APPROVAL	18,185,673		
24	2015 STORM DAMAGE-PENDING APPROVAL	24,157,767		
25	2016 STORM DAMAGE-PENDING APPROVAL	10,437,020		
26	2017 STORM DAMAGE-PENDING APPROVAL	12,215,519		
27	TOTAL (LINE 21 THROUGH LINE 26)	65,046,165		
28	ANNUAL AMORTIZATION (LINE 27 ÷ 48) x 12		16,261,541	
29				
30				
31	DEFERRED BALANCES FOR 10 YEAR AMORTIZATION AT			
32	START OF RATE YEAR (01/31/18):			
33	12/13/06 WIND STORM	-		
34	ORIGINAL AMORT PERIOD FROM UE-072300 WAS 10 YEARS, NOV 2008 - OCT 2018			
35	ANNUAL AMORTIZATION (LINE 33, 10 (01/2018 - 10/2018) x 10)		-	
36				
37	DEFERRED BALANCES FOR 6 YEAR AMORTIZATION AT			
38	01/18/12 SNOW STORM - PENDING APPROVAL	54,368,273		
39	ANNUAL AMORTIZATION (LINE 38, 72 (6 YEARS) X 12)		9,061,379	
40				
41	TOTAL RATE YEAR AMORTIZATION (LINE 28 + LINE 35 + LINE 39)		25,322,920	
42	LESS TOTAL TEST YEAR AMORTIZATION		15,477,396	
43				
44	INCREASE (DECREASE) OPERATING EXPENSE			9,845,524
45				
46	TOTAL INCREASE (DECREASE) OPERATING EXPENSE (LINE 16 + LINE 44)			9,442,213
47				
48	INCREASE (DECREASE) FIT @ 35% (LINE 46 X 35%)			(3,304,774)
49				
50	INCREASE (DECREASE) NOI			\$ (6,137,438)

**Exhibit G to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit G to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production Adjustment

LINE NO.	DESCRIPTION	PROFORMA AND RESTATED	PRODUCTION FACTOR	FIT 35%
1	APPLIED TO ALL BUT LINE 19	FIXED	0.000%	
2	APPLIED ONLY TO LINE 19	VARIABLE	3.839%	0.036322
3	OPERATING EXPENSE:			
4	O&M / A&G PRODUCTION RELATED			
5	WAGES & INCENTIVE - OTHER PWR 557	\$ 140,926	\$ -	\$ -
6	WAGES & INCENTIVE - PROD O&M	337,826	-	-
7	BENEFITS - A&G 926	8,206,061	-	-
8	WORKER'S COMP - A&G 926	214,072	-	-
9	PROPERTY INSURANCE - A&G 926	2,763,777	-	-
10	TOTAL PRODUCTION O&M / A&G	11,662,663	-	-
11				
12	DEPRECIATION / AMORTIZATION:			
13	DEPRECIATION	149,765,347	-	-
14	AMORTIZATION OF TREASURY GRANTS (407.4)	-	-	-
15	AMORTIZATION (OTHER THAN REGULATORY ASSETS/LIAB)	11,818,342	-	-
16	TOTAL DEPRECIATION / AMORTIZATION	161,583,689	-	-
17				
18	OTHER TAXES:			
19	MONTANA ENERGY TAX	1,313,078	(50,414)	17,645
20	PAYROLL TAXES	2,119,540	-	-
21	TOTAL OTHER TAXES	3,432,618	(50,414)	17,645
22				
23	AMORTIZATION ON REGULATORY ASSETS (EXCLUDES POWER REG AMORT)			
24	WHITE RIVER REGULATORY ASSET	6,553,641	-	-
25	TREASURY GRANTS DEFERRAL - SNOQUALMIE	(1,381,852)	-	-
26	TREASURY GRANTS DEFERRAL - BAKER	(400,022)	-	-
27	ELECTRON UNRECOVERED COSTS	3,786,308	-	-
28	MINT FARM DEFERRAL - UE-090704	2,885,052	-	-
29	LSR PLANT DEFERRAL - UE-111048	-	-	-
30	FERNDAL PLANT DEFERRAL - UE-130617	4,520,423	-	-
31	BAKER UPGRADE PLANT DEFERRAL UE-130617	561,126	-	-
32	SNOQUALMIE UPGRADE PLANT DEFERRAL UE-130617	2,203,436	-	-
33	FERC PART 12 STUDY NON-CONSTRUCTION COSTS UE-070074	-	-	-
34	CARRYING CHARGES ON LSR PREPAID TRANSM	687,420	-	-
35	TOTAL REGULATORY ASSET ADJUSTMENT TO DECOUPLING RATE	19,415,532	-	-
36		-		
37	INCREASE (DECREASE) EXPENSE		(50,414)	17,645
38	INCREASE(DECREASE) NOI			\$ 32,769
39				

Exhibit G to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production Adjustment

LINE NO.	DESCRIPTION	PROFORMA AND RESTATED	PRODUCTION FACTOR	FIT 35%
40				
41	RATEBASE:			
42	<u>PRODUCTION RATE BASE:</u>			
43	DEPRECIABLE PRODUCTION PROPERTY (INCLUDES HYDRO GRAN	\$ 3,894,737,851	\$ -	\$ 3,894,737,851
44	PRODUCTION PROPERTY ACCUM DEPR.	(1,711,022,636)	0	(1,711,022,636)
45	NON-DEPRECIABLE PRODUCTION PROPERTY	80,139,253	0	80,139,253
46	PRODUCTION PROPERTY ACCUM AMORT.	(9,933,315)	0	(9,933,315)
47	COLSTRIP COMMON FERC ADJUSTMENT	2,908,282	0	2,908,282
48	COLSTRIP DEFERRED DEPRECIATION FERC ADJ.	858,922	0	858,922
49	ACQUISITION ADJUSTMENT	281,543,145	0	281,543,145
50	ACCUMULATED AMORTIZATION ON ACQUISITION ADJ	(113,037,112)	0	(113,037,112)
51	NET PRODUCTION PROPERTY	2,426,194,391	-	2,426,194,391
52				
53				
54	<u>DEDUCT:</u>			
55	LIBR. DEPREC. POST 1980 (AMA)	(513,042,624)	0	(513,042,624)
56	NOL DEFERRED TAX ASSET ATTRIBUTABLE TO PRODUCTION	48,295,905	0	48,295,905
57	TREASURY GRANTS FOR SNOQUALMIE AND BAKER		0	0
58	ACCUM AMORT OF TREASURY GRANTS FOR SNOQUALMIE AND BAKER		0	0
59	ADJUSTMENT TO RATE BASE	(464,746,719)	-	(464,746,719)
60				
61	TOTAL ADJUSTMENT TO PRODUCTION RATE BASE	1,961,447,672	0	1,961,447,672
62				
63	<u>REGULATORY ASSETS RATE BASE (INCLUDES POWER COST REG ASSETS/LIAB):</u>			
64	TREASURY GRANTS DEFERRAL - SNOQUALMIE	(374,252)	0	(374,252)
65	TREASURY GRANTS DEFERRAL - BAKER	(108,339)	-	(108,339)
66	BEP	0	-	0
67	WHITE RIVER REGULATORY ASSET	10,649,666	-	10,649,666
68	WESTCOAST PIPELINE CAPACITY - UE-082013 (FB ENERGY)	(88,510)	-	(88,510)
69	WESTCOAST PIPELINE CAPACITY - UE-100503 (BNP PARIBUS)	(121,339)	-	(121,339)
70	CHELAN PUD CONTRACT INITIATION	82,196,761	-	82,196,761
71	CHELAN - ROCK ISLAND SECURITY DEPOSIT	18,500,000	-	18,500,000
72	COLSTRIP 1&2 (WEC) PREPAYMENT	750,000	-	750,000
73	FERC PART 12 STUDY NON-CONSTRUCTION COSTS UE-070074	0	-	0
74	LOWER SNAKE RIVER PREPAID TRANSM PRINCIPAL	60,863,794	-	60,863,794
75	CARRYING CHARGES ON LSR PREPAID TRANSM	8,466,701	-	8,466,701
76	MINT FARM DEFFRED - UE-090704 (ENDS MAR 2025)	12,550,110	-	12,550,110
77	LOWER SNAKE RIVER PLANT DEFERRAL (ENDS APR 2016)	0	-	0
78	FERNDAL PLANT DEFERRAL (ENDS OCT 2019)	3,917,700	-	3,917,700
79	SNOQUALMIE UPGRADE PLANT DEFERRAL (ENDS OCT 2018)	596,764	-	596,764
80	BAKER UPGRADE PLANT DEFERRAL (ENDS OCT 2018)	151,972	-	151,972
81	ELECTRON UNRECOVERED PLANT COSTS	1,128,004	-	1,128,004
82	TOTAL ADJUSTMENT TO REGULATORY ASSETS RATE BASE	\$ 199,079,031	\$ -	\$ 199,079,031
83		-		
84	TOTAL RATE BASE		\$ -	

**Exhibit H to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Exhibit A-1 Power Cost Baseline Rates With and Without Microsoft

<=Settlement=>													<=Contingent Calculation - NO MS Settlement=>												
Row		Test Year			Test Yr \$/MWh (II)	F/V (III)	Fixed Prod Cost In Decoupling (IV)		Variable Prod Cost In PCA (V)	Test Yr \$/MWh (II)	F/V (III)	Fixed Prod Cost In Decoupling (IV)		Variable Prod Cost In PCA (V)											
		(I)	(II)	(III)			(IV)	(V)				(VI)	(VII)												
3	Regulatory Assets (1) (Fixed)	\$	199,079,031																						
4	Transmission Rate Base (Fixed)		85,738,601																						
5	Production Rate Base (Fixed)		1,961,447,672																						
6		\$	2,246,265,304	6.55%																					
7	Net of tax rate of return																								
8																									
9																									
9A																									
10	Regulatory Asset Recovery (on Row 3)	\$	20,061,041	\$	0.968	F	\$	20,061,041	\$	0.989	F	\$	20,061,041	\$	-										
10a	Equity Adder Centralia Coal Transition PPA		4,769,481	\$	0.230	V																			
11	Fixed Asset Recovery Other (on Row 4)		8,639,813	\$	0.417	F		8,639,813	\$	0.426	F		8,639,813												
12	Fixed Asset Recovery-Prod Factored (on Row 5)		197,653,573	\$	9.538	F		197,653,573	\$	9.745	F		197,653,573												
13	501-Steam Fuel Incl PC Reg Amort		69,962,949	\$	3.376	V		69,962,949	\$	3.450	V		69,979,069		69,979,069										
14	555-Purchased power Incl PC Reg Amort		378,349,380	\$	18.257	V		378,349,380	\$	18.247	V		370,094,614		370,094,614										
15	557-Other Power Exp		7,238,267	\$	0.349	F		7,238,267	\$	0.357	F		7,238,267												
15a	Payroll Overheads - Benefits (Inc. Worker's Comp)		8,206,061	\$	0.396	F		8,206,061	\$	0.405	F		8,206,061												
15b	Property Insurance		2,763,777	\$	0.133	F		2,763,777	\$	0.136	F		2,763,777												
15c	Montana Electric Energy Tax		1,262,663	\$	0.061	V				0.062	V				1,262,954										
15d	Payroll Taxes on Production Wages		2,119,540	\$	0.102	F		2,119,540	\$	0.104	F		2,119,540												
15e	Brokerage Fees 55700003		313,332	\$	0.015	V				0.015	V				313,404										
16	547-Fuel Incl PC Reg Amort		171,115,374	\$	8.257	V		171,115,374	\$	8.433	V		171,056,253		171,056,253										
17	565-Wheeling Incl PC Reg Amort		108,374,278	\$	5.230	V		108,374,278	\$	5.344	V		108,399,249		108,399,249										
18	Transmission Revenue 456.1		(11,639,833)	\$	(0.562)	F		(11,639,833)	\$	(0.574)	F		(11,639,833)												
19	Production O&M		138,209,149	\$	6.669	F		138,209,149	\$	6.814	F		138,209,149												
20	447-Sales to Others		(36,228,867)	\$	(1.748)	V				(1.953)	V				(39,617,468)										
21	456-Purch/Sales Non-Core Gas		(16,223,873)	\$	(0.783)	V				(0.800)	V				(16,227,611)										
22	Transmission Exp - 500KV		662,135	\$	0.032	F		662,135	\$	0.033	F		662,135												
23	Depreciation-Production (FERC 403)		161,583,689	\$	7.797	F		161,583,689	\$	7.966	F		161,583,689												
24	Depreciation-Transmission		3,490,805	\$	0.168	F		3,490,805	\$	0.172	F		3,490,805												
25	Amortization - Regulatory Assets & Liab - Non PC Only (1)		19,415,532	\$	0.937	F		19,415,532	\$	0.957	F		19,415,532												
26	N/A (formerly hedging line of credit)																								
27	Subtotal & Baseline Rate	\$	1,240,098,267	\$	59.841	\$	558,403,549	\$	681,694,718	\$	60.565	\$	558,403,549	\$	670,031,044										
28	Revenue Sensitive Items		0.9523860		0.9523860		0.9523860		0.9523860		0.9523860		0.9523860		0.9523860										
29	Grossed up for RSI	\$	1,302,096,279	\$	62.833	\$	586,320,619	\$	715,775,660	\$	63.593	\$	586,320,619	\$	703,528,867										
30	Test Year DELIVERED Load (MWH's)		20,723,206	<-- Includes Firm Wholesale	Total																				
31																									
32	Baseline Rate Summarized																								
33	BLR Net of RSI		\$	\$	59.841	\$	26.946	\$	32.895		\$	27.531	\$	33.034											
34	BLR Crossed Up for RSI		\$	\$	62.833	\$	28.293	\$	34.540		\$	28.907	\$	34.686											

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft Compared to 2017 GRC Settlement

Revenue Deficiency Calculation

Puget Sound Energy
REVENUE (SURPLUS) / DEFICIENCY

Row	TY RY	17GRC Cont Calc	17GRC SETTLEMENT	(Surplus)/ Deficiency
		12MOE Sept 2016 Jan - Dec 2018	12MOE Sept 2016 Jan - Dec 2018	
1		\$ 670,031,044	\$ 681,694,718	
2		0.9523860	0.9523860	
3				
4		703,528,867	715,775,660	
5		20,282,959	20,723,206	
6				
7		\$ 34.686	\$ 34.540	\$ 0.146
8				
9				20,282,959
10				
11				\$ 2,961,312

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft

PUGET SOUND ENERGY

2017 GRC Settlement Contingent Calculation Power Costs Projections - AURORA + Not in Models

Rate Year January 2018 through December 2018

Gas Price date: June 23, 2017

(dollars are in thousands)

2017 GRC Settlement Contingent Calculation - Prices at June 23, 2017

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	17GRC Settlement Contingent Calculation
501 Coal Fuel	\$ 7,667	\$ 7,191	\$ 7,080	\$ 4,766	\$ 3,346	\$ 3,126	\$ 6,281	\$ 6,821	\$ 6,270	\$ 6,376	\$ 6,546	\$ 7,286	\$ 72,756
547 Natural Gas Fuel	\$ 18,744	\$ 19,551	\$ 15,190	\$ 9,554	\$ 5,587	\$ 7,509	\$ 13,968	\$ 17,812	\$ 17,030	\$ 16,962	\$ 17,154	\$ 18,784	\$ 177,845
555 Purchase & Interchang	\$ 41,810	\$ 33,815	\$ 35,231	\$ 31,390	\$ 32,114	\$ 27,277	\$ 24,058	\$ 20,307	\$ 23,411	\$ 27,853	\$ 37,224	\$ 50,292	\$ 384,783
557 Other Power Supply	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 763	\$ 9,156
565 Wheeling	\$ 9,559	\$ 9,610	\$ 9,696	\$ 9,545	\$ 9,484	\$ 9,255	\$ 9,177	\$ 9,228	\$ 9,151	\$ 9,230	\$ 9,322	\$ 9,444	\$ 112,701
447 Secondary Sales	\$ (2,322)	\$ (4,583)	\$ (2,081)	\$ (1,699)	\$ (1,467)	\$ (1,878)	\$ (7,801)	\$ (9,017)	\$ (6,563)	\$ (2,709)	\$ (939)	\$ (133)	\$ (41,190)
456 Non-Core Gas	\$ (2,712)	\$ (2,132)	\$ (1,362)	\$ (740)	\$ (549)	\$ (523)	\$ (1,026)	\$ (853)	\$ (947)	\$ (1,482)	\$ (1,664)	\$ (2,880)	\$ (16,872)
Total Power Costs	\$ 73,510	\$ 64,216	\$ 64,517	\$ 53,579	\$ 49,279	\$ 45,529	\$ 45,420	\$ 45,061	\$ 49,116	\$ 56,993	\$ 68,405	\$ 83,556	\$ 699,180
Load in MWh	2,302,758	1,980,831	2,081,173	1,810,029	1,670,500	1,610,630	1,675,432	1,687,118	1,629,861	1,818,573	2,044,704	2,461,824	22,773,433

Settlement Power Costs
Diff

711,469.7
(12,289.9)

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft

Puget Sound Energy
Variable Cost Production Factor (NO MS)
Test Year ending September 2016
Rate Year Ending December 2018

Line No	Tariff	Description	Delivered MWh YE September 2016	Temperature Adjustment	Delivered & Normalized MWh YE September 2016	Delivered MWh YE December 2018 (F2016)
1	7	Secondary Voltage - Residential				
2	7A	Secondary Voltage - Residential Multi-Meter				
3	24	Secondary Voltage - Small General Service				
4	25	Secondary Voltage - Medium General Service				
5	26	Secondary Voltage - Large General Service				
6	29	Secondary Voltage - Irrigation Service				
7	31	Primary Voltage - General Service				
8	35	Primary Voltage - Irrigation Service				
9	43	Primary Voltage - Interruptible Schools				
10	40	Campus Service				
11	46	High Voltage - Interruptible Service				
12	49	High Voltage - General Service				
13	50-59	Lighting				
14	449-45	Retail Wheeling				
15	5	Wholesale For Resale				
16						
17	Total					
18						
19	Retail Wheeling Load					
20	Total Less Retail Wheeling (Excluding Micro		20,001,252	281,707	20,282,959	21,087,937
21						
22	Complement of Variable Production Factor					96.183%
23	Variable Production Factor					3.817%

**Exhibit I to the
Multiparty Settlement
Stipulation and Agreement**

Exhibit I to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Parameters for the Expedited Rate Filing Authorized by Section III.H. of the
Multiparty Settlement Stipulation and Agreement

The Expedited Rate Filing (“ERF”) for Puget Sound Energy authorized by Section III.H. of the Multiparty Settlement Stipulation and Agreement, dated September 15, 2017, in Dockets UE-170033 and UG-170034 will be based on a Commission Basis Report (“CBR”) developed for a recently completed accounting period consistent with the approach defined in WAC 480-90-257 and WAC 480-100-257.

The ERF will use only restating adjustments most recently approved by the Commission, with the following exceptions:

- (i) Use of end of period rate base is acceptable.
- (ii) Annualization of any revenues that occurred after the test period and annualization of the underlying costs associated with those revenues to the extent not fully included in the test year results. This is necessary to maintain proper matching of the annualized revenue and expenses.

The ERF will remove power costs, purchased gas, and gas pipeline cost recovery mechanism (and if approved Electric Cost Recovery Mechanism) related revenues, rate base and expenses leaving only transmission, distribution and administration and general costs and rate base that will be used to determine the electric and natural gas revenue requirements to be considered in the expedited rate filing.

The ERF shall maintain the rate of return established in the most recent general rate case except to update the interest rate on debt if needed.

The ERF will not include changes to rate spread or rate design from the most recently filed general rate case.

ORDER NO. 03-455

ORDER NO. 03-455

ENTERED JUL 24 2003

This is an electronic copy. Format and font may vary from the official version. Attachments may not appear.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1088

In the Matter of	)	
	)	
PACIFIC POWER & LIGHT (dba	)	
PACIFICORP)	)	ORDER
	)	
Application for an Accounting Order	)	
Regarding Treatment of Certain Asset	)	
Retirement Obligations.	)	

DISPOSITION: APPLICATION APPROVED WITH CONDITION

On May 27, 2003, Pacific Power & Light (PacifiCorp) filed an application with the Public Utility Commission (Commission) requesting an accounting order authorizing PacifiCorp to 1) record, as a regulatory asset or a regulatory liability, the cumulative financial statement impact resulting from PacifiCorp's implementation of Statement of Financial Accounting Standards (SFAS) 143; and 2) record on an ongoing basis, as a regulatory asset or regulatory liability, an amount equal to the difference between the annual SFAS accretion and depreciation expenses and the annual depreciation expenses based on Commission-approved depreciation expense.

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, *Accounting for Asset Retirement Obligations*, effective for fiscal years after June 15, 2002. Under SFAS 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that PacifiCorp has traditionally recognized and accounted for such costs. Staff's recommendation is attached as Appendix A and is incorporated by reference.

At its Public Meeting on June 15, 2003, the Commission adopted Staff's Recommendations and approved PacifiCorp's current request with one condition.

ORDER

IT IS ORDERED that:

- 1) Pacific Power & Light Company's accounting application is approved, subject to one condition.
- 2) At any time Pacific Power & Light Company files a results of operations report or general rate change, for a period of five years, Pacific Power & Light Company must provide the Public Utility Commission with all journal entries made under the requirements of SFAS 143 and any adjustments necessary to remove rate impacts of this accounting treatment.

Made, entered and effective _____.

BY THE COMMISSION:

Becky Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A party may appeal this order to a court pursuant to ORS 756.580.

ITEM NO. CA4

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 15, 2003**

REGULAR _____ **CONSENT** X **EFFECTIVE DATE** April 1, 2003

DATE: June 17, 2003

TO: John Savage through Lee Sparling and Ed Busch

FROM: Judy Johnson

SUBJECT: PACIFIC POWER & LIGHT; (Docket No. UM 1088) Requests Accounting Order Regarding Treatment of Certain Asset Retirement Obligations

SUMMARY RECOMMENDATION:

I recommend the Commission approve Pacific Power & Light Company's accounting application, with one condition.

DISCUSSION:

On May 27, 2003, Pacific Power & Light Company (PacifiCorp or company) filed an application requesting an accounting order authorizing the company to 1) record, as a regulatory asset or a regulatory liability, the cumulative financial statement impact resulting from the company's implementation of Statement of Financial Accounting Standards (SFAS) 143; and 2) record on an ongoing basis, as a regulatory asset or regulatory liability, an amount equal to the difference between the annual SFAS accretion and depreciation expenses and the annual depreciation expensed based on Commission-approved depreciation expense.

On June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, *Accounting for Asset Retirement Obligations*, effective for fiscal years after June 15, 2002. Under SFAS 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that PacifiCorp has traditionally recognized and accounted for such costs.

Specifically, if a legally enforceable asset retirement obligation (ARO), as defined by SFAS 143, is deemed to exist, an entity must measure and record the liability for the ARO on its books at fair market value in the period during which the liability is incurred. At the time the liability is recorded, a corresponding and equivalent ARO asset is also recorded on the entity's books as part of the cost of the associated tangible asset. The ARO asset is then depreciated over the life of the associated tangible asset. In addition, accretion is added to the ARO liability annually to account for the time value of

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APPENDIX A
PAGE 1 OF 5

money, so that at the time of retirement the recorded ARO liability will be sufficient to provide the cash required to meet the legal obligation.

In addition to the forward-looking requirements of SFAS 143, entities are required to recognize the cumulative impact on their financial statements resulting from the implementation of SFAS 143. This cumulative impact amounts to a transition entry on the entity's books, so that in future years the financial statements will appear as if the requirements of SFAS 143 had always been followed. Neither the SFAS 143 transition entries nor the annual accounting entries will change the level of costs included in rates.

PacifiCorp is required to implement SFAS 143 in order to comply with Generally Accepted Accounting Principles. The company has determined that it will need to record AROs under SFAS 143 for certain generation and mining assets. The company has also identified AROs for transmission and distribution assets. However, the timing of those obligations is indeterminate and the liability cannot be measured and recorded at this time. There were no material AROs for general plant assets.

The company's proposed accounting treatment will use SFAS 143 for reporting on its financial statements, but retain its current methodology for ratemaking purposes. SFAS 143 recognizes that differences may exist between its requirements and the treatment of ARO costs for regulatory purposes and provides that a regulated entity subject to SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, can recognize any differences between the two approaches as a regulatory asset or a regulatory liability, subject to the requirements of SFAS 71.

Under the accounting method currently used by the company for both financial reporting and ratemaking purposes, the cost of removing a tangible long-lived asset at retirement is included in the calculation of depreciation rates as negative salvage and is recovered over the useful life of the asset. Under this method, the accrued removal cost is included in Account 108, Accumulated Depreciation.

PacifiCorp believes, and Staff agrees, that it is not appropriate to apply the requirements of SFAS 143 in determining AROs for ratemaking purposes. Rather, the company believes, and Staff agrees, that AROs should continue to be established through traditional depreciation studies and recovered through the application of Commission-approved depreciation rates. SFAS 143 should not be used for ratemaking for several reasons detailed in the attachment to the Staff report.

Nothing in this application requests any approval regarding future ratemaking treatment. PacifiCorp notes, however, that upon retirement of the related assets and determination of actual removal costs, such costs will be trued-up for ratemaking purposes, at which time the regulatory accounts associated with these assets will be eliminated. For

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APPENDIX A
PAGE 2 OF 5

regulatory reporting purposes, the effects of SFAS 143 will be removed and there should be no rate change, now or in the future, associated with the application of the requested accounting treatment.

PacifiCorp also requests confirmation by the Commission that asset removal costs, in the form of negative net salvage, are currently accrued through annual depreciation expense which is recoverable in rates; that these costs are based on estimates of the final removal cost; and that such costs are trued-up for ratemaking purposes at the time the related assets are retired and the actual removal costs are determined. Staff does not believe that this confirmation should be in a formal Commission motion for accounting approval. However, Staff acknowledges that the company's characterization of the Commission's current ratemaking practices in regard to asset removal costs is correct.

PROPOSED COMMISSION MOTION:

Pacific Power & Light Company's accounting application in UM 1088 be approved, subject to the following condition: At any time PacifiCorp files a results of operations report or general rate change, for a period of five years, the company must provide Staff with all journal entries made under the requirements of SFAS 143 and any adjustments necessary to remove rate impacts of this accounting treatment.

Attachment

PacifiCorp UM 1088

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.....

ATTACHMENT A

SFAS 143 should not be used for ratemaking for the following reasons:

1. The primary focus of SFAS 143 is on financial statement presentation rather than cost recovery.

- The FASB provided the following two reasons for issuing FAS 143: (1) Users of financial statements indicated that the diverse accounting practices that have developed for obligations associated with the retirement of tangible long-lived assets make it difficult to compare the financial position and results of operations of companies that have similar obligations but account for them differently; and (2) Obligations that meet the definition of a liability were not being recognized when those liabilities were incurred or the recognized liability was not consistently measured or presented.
- The provisions of FAS 143 are primarily focused on determining the appropriate amount of the ARO liability to be reflected in the financial statements.
- For ratemaking purposes the issue with asset removal cost is not balance sheet presentation. The ratemaking issue is how to properly estimate removal costs and how to recover them in a fair and equitable manner from the utility customers being served by the assets. This process of estimation and recovery is best accomplished through traditional utility depreciation procedures that are subject to regulatory review and oversight.

2. Adoption of SFAS 143 for ratemaking would effectively transfer the determination of the appropriate amount of asset removal cost from regulators to the FASB.

- When removal costs are determined through a depreciation study, if the Commission disagrees with the company's estimates, the estimates are simply changed and the depreciation rates adjusted accordingly.
- If the SFAS 143 estimates of removal cost are to be used for ratemaking, then the Commission must accept whatever amount is calculated by the company and determined by its external auditors to be in compliance with SFAS 143.

3. Under the provisions of SFAS 143, the recognition of removal cost in period expense over the life of the asset is "back-end loaded".

As a result of the application of present value techniques, SFAS 143 results in removal expense that is lower in the early years of asset life and greater in the final years.

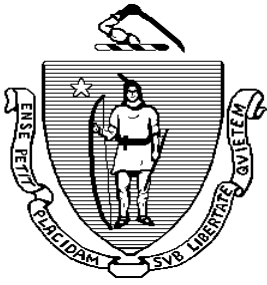
APPENDIX A
PAGE 4 OF 5

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- In contrast, for ratemaking purposes the goal of a depreciation study is to recover the cost of an asset, including removal cost, on a straight-line basis over the productive life of the asset.
4. The methods for determining the amount of removal cost required by SFAS 143 are different than those traditionally used in utility depreciation analysis and adopted for ratemaking purposes, leading to potentially higher cost estimates.
- SFAS 143 requires that the value of the removal liability be determined based on "fair value", which would ideally be based on a market price. In other words SFAS 143 assumes that asset removal would be accomplished by a third party engaged by the utility. Use of a third party involves recognizing a profit margin in the removal cost estimate.
 - As a practical matter, utilities would normally use their own workforces to the extent possible to remove and dispose of utility assets. Thus the requirement by SFAS 143 to include a third-party profit margin could lead to higher removal cost estimates than would be included in a traditional depreciation study.
5. Use of SFAS 143 for ratemaking would create additional regulatory oversight issues.
- Under current procedures, all changes in asset lives as well as changes in asset salvage and removal costs are contained in a single comprehensive depreciation study that is prepared and submitted for regulatory review and approval at periodic intervals (normally five years).
 - If SFAS 143 were adopted for ratemaking, it would still be necessary to prepare a depreciation study and submit it for review and approval. In addition, for assets that qualify for SFAS 143 treatment, regulators would need to conduct a separate review of ARO calculations, interest rate determinations, the calculation of annual accretion and ARO asset amortization expense, etc.
 - When the recovery of asset removal costs is approved through a depreciation study, it remains in effect until the next study is prepared, typically five years. Potentially, under the provisions of SFAS 143, new AROs could be added and the amounts of existing AROs could be updated each year; requiring virtually continuous regulatory oversight.

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APPENDIX A
PAGE 5 OF 5



The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-05-F

May 11, 2018

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism.

ORDER ON EVERSOURCE'S MOTION FOR RECONSIDERATION AND MOTION FOR LEAVE TO FILE A REPOSE

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I.	INTRODUCTION AND RELEVANT PROCEDURAL HISTORY	1
II.	EVERSOURCE'S MOTION FOR RECONSIDERATION	2
A.	Introduction	2
B.	Standard of Review.....	4
C.	Positions of the Parties	5
1.	Eversource	5
2.	Attorney General	8
D.	Analysis and Findings	10
1.	Introduction	10
2.	Depreciation Rates	10
3.	Net Salvage Analysis	11
4.	Reconsideration	13
5.	Other Issues.....	18
6.	Conclusion	20
III.	SCHEDULES – NSTAR ELECTRIC COMPANY.....	21
A.	Schedule 1 – Revenue Requirements and Calculation of Revenue Increase....	21
B.	Schedule 2 – Operations and Maintenance Expenses	22
C.	Schedule 3 – Depreciation and Amortization Expenses	23
D.	Schedule 4 – Rate Base and Return on Rate Base.....	24
E.	Schedule 5 – Cost of Capital	25
F.	Schedule 6 – Cash Working Capital	26
G.	Schedule 7 – Taxes Other Than Income Taxes	27
H.	Schedule 8 – Income Taxes.....	28
I.	Schedule 9 – Revenues	29
IV.	SCHEDULES – WESTERN MASSACHUSETTS ELECTRIC COMPANY	30
A.	Schedule 1 – Revenue Requirements and Calculation of Revenue Increase....	30
B.	Schedule 2 – Operations and Maintenance Expenses	31
C.	Schedule 3 – Depreciation and Amortization Expenses	32
D.	Schedule 4 – Rate Base and Return on Rate Base.....	33
E.	Schedule 5 – Cost of Capital	34
F.	Schedule 6 – Cash Working Capital	35
G.	Schedule 7 – Taxes Other Than Income Taxes	36
H.	Schedule 8 – Income Taxes.....	37
I.	Schedule 9 – Revenues	38
V.	ORDER.....	39

I. INTRODUCTION AND RELEVANT PROCEDURAL HISTORY¹

On January 17, 2017, NSTAR Electric Company (“NSTAR Electric”) and Western Massachusetts Electric Company (“WMECo”), each doing business as Eversource Energy (collectively, “Eversource” or “Companies”) filed a petition with the Department of Public Utilities (“Department”) seeking approval of increases in base distribution rates for electric service pursuant to G.L. c. 164, § 94, as well as other proposals.² The Department docketed this matter as D.P.U. 17-05. On January 25, 2017, the Attorney General of the Commonwealth of Massachusetts (“Attorney General”) filed a notice of intervention pursuant to G.L. c. 12, § 11E (a).³

¹ For a complete procedural history of this proceeding, refer to NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 5-11 (2017).

² In D.P.U. 17-05, at 28-55, the Department approved the corporate consolidation of WMECo with and into NSTAR Electric pursuant to G.L. c. 164, § 96. The legal name of Eversource’s electric distribution company in Massachusetts is now NSTAR Electric Company d/b/a Eversource Energy.

³ The other full party intervenors in this case are: (1) Acadia Center; (2) Associated Industries of Massachusetts; (3) the City of Cambridge; (4) the towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Edgartown, Eastham, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, West Tisbury, Wellfleet, and Yarmouth, as well as Barnstable County and Dukes County, acting together as the Cape Light Compact; (5) Conservation Law Foundation; (6) Department of Energy Resources; (7) the Federal Executive Agencies; (8) Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association; (9) Northeast Clean Energy Council; (10) Retail Energy Supply Association; (11) The Energy Consortium; (12) University of Massachusetts; and (13) Western Massachusetts Industrial Group. The following entities were granted limited intervenor status: (1) the Town of Barnstable; (2) Cape and Vineyard Electric Cooperative; (3) ChargePoint, Inc.; (4) Choice Energy, LLC; (5) Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, Direct Energy Services, LLC, and Direct Energy Solar, LLC; (6) the Energy Consumers Alliance of New England, Inc., d/b/a Massachusetts

On November 30, 2017, the Department issued a final Order establishing Eversource's revenue requirement. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (2017). On January 5, 2018, the Department issued a final Order establishing Eversource's rate structure. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05-B (January 5, 2018). Eversource's new rates took effect on February 1, 2018, following approval of the Eversource's compliance filing. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05-C (February 2, 2018). On March 20, 2018, the Department issued an Order on the Attorney General's Motion for Reconsideration and Clarification and Motion for Extension of the Judicial Appeal Period. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05-D (March 20, 2018). On April 4, 2018, the Department issued an Order on Vote Solar's Motion for Clarification. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05-E (April 4, 2018).

II. EVERSOURCE'S MOTION FOR RECONSIDERATION

A. Introduction

As discussed in D.P.U. 17-05, at 181-182, Eversource prepared depreciation studies for NSTAR Electric and WMECo and calculated annual depreciation accrual rates by plant account for all electric plant as of June 30, 2016. In D.P.U. 17-05, at 209, the Department found that for 14 accounts⁴ Eversource's proposed net salvage factors overstated the Companies' salvage costs and

Energy Consumers Alliance and the Sierra Club; (7) the City of Newton and the Towns of Arlington, Lexington, Natick and Weston; (8) PowerOptions, Inc.; (9) Sunrun, Inc. and the Energy Freedom Coalition of America, LLC; and (10) Vote Solar.

⁴ The 14 subject accounts are NSTAR Electric's accounts 366, 367, 369.1, 369.2, and 373, and WMECo's accounts 362, 364, 365, 366, 367, 369.1, 369.2, 370, and 371.

produced excessive depreciation accrual rates. The Department determined that, for those 14 subject accounts, the Attorney General's proposed salvage factors struck a reasonable balance between historic net salvage trends, more recent net salvage trends, and the Companies' anticipated future net salvage costs, while also maintaining the theoretical depreciation reserve. D.P.U. 17-05, at 209. Therefore, the Department determined that for the 14 subject accounts it would use the Attorney General's proposed net salvage rates in determining Eversource's depreciation accrual rates. D.P.U. 17-05, at 209.

On December 20, 2017, Eversource filed a Motion for Reconsideration ("Eversource's Motion") related to the aforementioned findings. On January 3, 2018, the Attorney General filed an Opposition to the Motion ("Attorney General's Opposition"). No other party responded to Eversource's Motion.

On January 19, 2018, Eversource filed a Motion for Leave to File a Response to the Attorney General Opposition ("Eversource's Motion for Leave") and a Response to the Attorney General's Opposition ("Eversource's Response"). On January 26, 2018, the Attorney General filed an Opposition and Cross-Motion to Strike the Companies' Response ("Attorney General's Motion to Strike"). Given the Department's findings below, we need not reach the merits of Eversource's Motion for Leave, Eversource's Response, or the Attorney General's Motion to Strike. Thus, our analysis below is based on the arguments raised in Eversource's Motion and the Attorney General's Opposition.

B. Standard of Review

The Department's Procedural Rule, 220 CMR 1.11(10), authorizes a party to file a motion for reconsideration within 20 days of service of a final Department Order. The Department's policy on reconsideration is well-settled. See, e.g., Boston Edison Company, D.P.U. 90-270-A at 2-3 (1991); Western Massachusetts Electric Company, D.P.U. 558-A at 2 (1981).

Reconsideration of previously decided issues is granted when extraordinary circumstances dictate that we take a fresh look at the record for the express purpose of substantively modifying a decision reached after review and deliberation. The Berkshire Gas Company, D.P.U. 905-C at 6-7 (1982) (finding extraordinary circumstances where union contract expiration and subsequent strike prevented company from providing ratified union contract payroll increases until several days after final Order issued); cf. Boston Gas Company, D.P.U. 96-50-C (Phase I) at 25 (1997) (finding creation of nonunion compensation pool after the close of the record was not an extraordinary circumstance). Alternatively, a motion for reconsideration may be based on the argument that the Department's treatment of an issue was the result of mistake or inadvertence. See, e.g., Boston Gas Company, D.P.U. 96-50-C (Phase I) at 22 (1997); New England Telephone and Telegraph Company, D.P.U. 86-33-J at 2, 25-26 (1989); Boston Edison Company, D.P.U. 1350-A at 5 (1983).

A motion for reconsideration should not attempt to reargue issues considered and decided in the main case. See, e.g., Commonwealth Electric Company, D.P.U. 92-3C-1A at 3-6 (1995); Boston Edison Company, D.P.U. 90-270-A at 2-3, 7-9 (1991); Boston Edison Company, D.P.U. 1350-A at 4-5 (1983). The Department has denied reconsideration where the request rests

upon information that could have been provided during the course of the proceeding and before issuance of the final Order. See, e.g., Boston Gas Company, D.P.U. 96-50-C (Phase I) at 36-37 (1997); Boston Gas Company, D.P.U. 96-50-B (Phase I) at 8 (1997). The Department has stated that the record in a proceeding closes, at the latest, when an Order is issued. Western Massachusetts Electric Company, D.P.U. 85-270-C at 18-20 (1987). Thus, the Department may deny reconsideration when the request rests on a new issue or updated information presented for the first time in the motion for reconsideration. See, e.g., Western Massachusetts Electric Company, D.P.U. 85-270-C at 18-20 (1987).

C. Positions of the Parties

1. Eversource

Eversource argues that the Department made a mistake in adopting the Attorney General's net salvage factors for the subject 14 accounts (Eversource's Motion at 4). First, Eversource argues that in adopting the Attorney General's proposed net salvage factors, the Department failed to specify the resulting approved depreciation rates (Eversource's Motion at 2, 5, 11). As a result, Eversource claims that there is no connection between the depreciation expense level approved by the Department and the three components of depreciation rates – capital recovery, cost of removal and gross salvage – and, therefore, depreciation rates cannot be generated from the Department's decision (Eversource's Motion at 5).

Next, Eversource argues that the Department failed to explain how the net salvage expense adjustment recommended by the Attorney General was specifically calculated, or how the computation was reasonable, appropriate, and correct, particularly when, as Eversource contends, the calculation does not arise from a depreciation study or any reasonable methodological approach

(Eversource's Motion at 5, 7-8, 10-11). In this regard, Eversource asserts that its depreciation witness followed the traditional method for calculating net salvage factors, as set forth in Depreciation Systems, written by Frank K. Wolf and W. Chester Fitch, and consistent with long-standing Department precedent (Eversource's Motion at 6, citing Exhs. ES-JJS-2, at 150-175; ES-JJS-3, at 126-144; ES-JJS-Rebuttal, at 30-36; Tr. 9, at 1735-1737; ES-1, at 261, 271; Bay State Gas Company, D.P.U. 12-25, at 307 (2012); Boston Edison Company, D.P.U. 1350, at 97, 107-111 (1983)).

In contrast, Eversource argues that the Attorney General's depreciation witness did not produce a depreciation study or follow any valid industry methodology for developing her proposed salvage factors for the subject 14 accounts (Eversource's Motion at 6). Further, Eversource claims that the Attorney General's depreciation witness omitted pertinent parts of the Depreciation Systems text from its exhibits and admitted that he did not generate schedules consistent with the methodology supported by Depreciation Systems (Eversource's Motion at 6-7). According to Eversource, the Attorney General's witness started with the expense levels generated by the net salvage factors derived in the Companies' depreciation studies and then worked backwards to reduce those expense levels to amounts that the witness arbitrarily deemed to be acceptable (Eversource's Motion at 7, citing Tr. 9, at 1745-1747, 1758-1759). Eversource also contends that the Attorney General's witness has a history of proposing salvage values across various jurisdictions that are based on arbitrary assessments as to the ultimate expense level that the witness seeks to recommend – i.e., according to Eversource, the witness's approach is results-oriented rather than based on a valid depreciation study or method (Eversource's Motion at 8). Thus,

Eversource asserts that it is unclear what the Attorney General's method is in deriving the recommended expense level in a particular jurisdiction (Eversource's Motion at 8).

Eversource argues that the Department's decision in D.P.U. 17-05 does not reference or address how the Attorney General's approach of "backing into" a number is legitimate or why this approach is more valid from a methodological perspective than relying on the result of the Companies' depreciation studies and analysis of salvage factors (Eversource's Motion at 7-8). According to Eversource, this constitutes a material omission by the Department and creates a fundamental legal deficiency in the Department's decision (Eversource's Motion at 8-10, citing Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 242 (2002); Massachusetts Institute of Tech. v. Department of Public Utilities, 425 Mass. 856, 868 (1997)). Further, Eversource contends that the Department's decision that the Attorney General's proposed salvage factors "'strike a reasonable balance between historic net salvage trends, more recent net salvage trends, and the Companies' anticipated future net salvage costs, while maintaining the theoretical depreciation reserve,'" is deficient and contrary to established ratemaking practice in relation to depreciation studies and net salvage parameters (Eversource's Motion at 5-6, 10, 12, citing D.P.U. 17-05, at 209; Fitchburg Gas and Electric Light Company, D.P.U. 15-80/15-81, at 214-228 (2016); NSTAR Gas Company, D.P.U. 14-150, at 183-196 (2015); D.P.U. 12-25, at 307; D.P.U. 1350, at 97, 107-111). Thus, Eversource asserts that the Department's decision violates the principle of reasoned consistency (Eversource's Motion at 12, citing Boston Gas Company v. Department of Public Utilities, 367 Mass 92, 104, 105 (1975)).

Based on all of the foregoing reasons, Eversource argues that the Department's adoption of the Attorney General's salvage factors is subject to reconsideration because of legal error (Eversource's Motion at 12). Accordingly, Eversource asserts that the Department's decision warrants reconsideration (Eversource's Motion at 12).

2. Attorney General

The Attorney General argues that the Department did not make a mistake in adopting her recommended net salvage factors (Attorney General's Opposition at 4). First, the Attorney General disagrees with Eversource's claims that the Department's decision fails to specify the resulting depreciation rates or that the Companies are unable derive such rates from the decision (Attorney General's Opposition at 3). The Attorney General notes that the Department did, in fact, make a finding that it would use the Attorney General's proposed net salvage rates in determining Eversource's depreciation accrual rates (Attorney General's Opposition at 3, citing D.P.U. 17-05, at 209; Exh. AG-WWD-1, at 31). Further, the Attorney General contends that in order to determine the overall depreciation rates, the Companies need only "swap out" their proposed net salvage rates for the Attorney General's rates (Attorney General's Opposition at 3-4, citing Exh. AG-WWD-1, at 31). According to the Attorney General, the record already includes this calculation, as she contends that her witness calculated the depreciation accrual rates that result from the proposed net salvage factors for each contested account, as well as those accounts' composite remaining lives (Attorney General's Opposition at 4, citing Exh. AG-WWD-3, at 2, 4, 7, 9).

Next, the Attorney General argues that there is no Department requirement for a party to conduct its own depreciation study in order to make recommendations on adjustments to a petitioner's proposed depreciation accrual rates (Attorney General's Opposition at 5). She notes that in prior cases, the Department has made such adjustments based on evidence outside of a company's depreciation study (Attorney General's Opposition at 5, citing D.P.U. 14-150, at 194-195; D.P.U. 12-25, at 316, 318, 322-323). The Attorney General contends that in the instant case, she substantially agreed with Eversource's depreciation studies, with the exception of the proposed accrual rates for the 14 subject accounts, for which she claims she provided sufficient evidence to support her recommended accrual rates (Attorney General's Opposition at 5, citing Exhs. AG-WWD-1, AG-WWD-Surrebuttal-1; Tr. 9, at 1703-1800). Thus, according to the Attorney General, there was no need for her to conduct a separate depreciation study (Attorney General's Opposition at 5).

Further, the Attorney General disputes that Eversource's method of establishing depreciation rates (i.e., through depreciation studies) was wholly objective (Attorney General's Opposition at 6).⁵ Rather, the Attorney General asserts that all net salvage analyses require some degree of subjectivity and that the Department did not make a mistake when it adopted her subjective analysis over Eversource's subjective analysis (Attorney General's Opposition at 6). In

⁵ The Attorney General contends that Eversource rehashes its arguments regarding its purported use of the traditional approach to developing depreciation rates (Attorney General Opposition at 6). She claims that Eversource raised these arguments during the evidentiary phase of the proceeding and in briefs and that the Department already considered such arguments (Attorney General's Opposition at 6, citing D.P.U. 17-05, at 208). Thus, the Attorney General asserts that Eversource's Motion should not attempt to reargue these issues (Attorney General's Opposition at 6, citing D.P.U. 92-3C-1A, at 3-6 (1995); D.P.U. 90-270-A, at 2-3, 7-9; D.P.U. 1350-A, at 4-5).

this regard, she argues that the Eversource's depreciation expert erroneously included future inflation in the Companies' proposed depreciation expense and, therefore, it was proper for the Department to find that such costs were inflated (Attorney General's Opposition at 7, citing Exhs. AG-WWD-1, at 24 n.24; AG-WWD-Surrebuttal-1, at 2-3, 21-22; AG-WWD-Surrebuttal-2).

For all of these reasons, the Attorney General argues that Eversource has failed to demonstrate that the Department's decision was based on a mistake that requires reconsideration (Attorney General's Opposition at 2, 4-5, 6, 7). Accordingly, the Attorney General asserts that the Department should deny the Eversource's Motion (Attorney General's Opposition at 2, 8).

D. Analysis and Findings

1. Introduction

As noted above, Eversource raises two main arguments in support of its request for reconsideration. First, Eversource argues that reconsideration is appropriate because the Department, in adopting the Attorney General's recommended net salvage factors for the 14 subject accounts, failed to specify the resulting depreciation rates (Eversource's Motion at 2, 5, 11). Second, Eversource contends that the Department failed to adequately support its decision to adopt the Attorney General's recommended net salvage expense adjustment, particularly given that the recommended net salvage factors did not result from a depreciation study or any reasonable methodological approach (Eversource's Motion at 5, 7-8, 10-11).

2. Depreciation Rates

Regarding Eversource's first argument, in D.P.U. 17-05, at 211, the Department noted that it applied the Attorney General's proposed accrual rates to the Companies' depreciable plant balances included in rate base to calculate the Companies' annual depreciation expense. While it

did not include a table of the approved accrual rates, the Department did indicate that such a table was provided by the Attorney General. D.P.U. 17-05, at 187, citing Exhs. AG-WWD-1, at 32; AG-WWD-3, at 1-6. Therefore, we are not persuaded by Eversource's argument that the Department failed to provide the approved accrual rates or the annual depreciation expense resulting from those accrual rates.

3. Net Salvage Analysis

Regarding the Attorney General's second argument, Eversource maintains that the Attorney General's approach of "backing into" net salvage factors that her witness arbitrarily deemed to be acceptable is results-oriented and not based on a valid methodology (Eversource's Motion at 6-8). The Attorney General counters that the selection of net salvage factors includes some degree of subjectivity, and the Department's decision to adopt one subjective analysis over another is not a mistake that provides a basis for reconsideration (Attorney General's Opposition at 6).

As an initial matter, we note that there is no express Department requirement for a party to present its own depreciation study to recommend adjustments to a petitioning company's proposed depreciation accrual rates. The Department has routinely adjusted net salvage factors, including those proposed by Eversource's own depreciation witness, in prior rate proceedings without the need to either perform a new depreciation study or to disaggregate net salvage in the manner apparently sought by Eversource. D.P.U. 14-150, at 190, 195; D.P.U. 12-25, at 316-318, 323; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 197 (2009); D.P.U. 08-27, at 116; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 136-137,

139, 142 (2003); D.P.U. 92-250, at 68, 70.⁶ Thus, we find that the Attorney General's failure to provide a separate depreciation study does not preclude the adoption of her recommended net salvage factors, so long as the underlying basis for any such recommendations is well grounded and consistent with Department ratemaking standards.

On this last point, we note that the Department's original decision to amend the Companies' proposed net salvage factors rested upon a determination that Eversource, having failed to discount its salvage values for the time value of money, inappropriately included inflation in the cost of removal data, which for the 14 subject accounts resulted in inflated net salvage factors and produced excessive depreciation accrual rates. D.P.U. 17-05, at 205-207.⁷ This finding was based in part on instruction from Depreciation Systems that "[a] first step in salvage analysis is to convert the observed dollars to constant dollars," which the Attorney General claimed Eversource failed to do. D.P.U. 17-05, at 190-191, 205, citing Exhs. AG-WWD-Surrebuttal-2, at 8; ES-1, at 5; Attorney General Brief at 158.⁸ Ultimately, the Department determined that, for the 14 subject

⁶ Additionally, the Department has revised proposed life analyses without the need to perform a new depreciation study. D.P.U. 14-150, at 193; Milford Water Company, D.P.U. 12-86, at 229-230 (2013); D.P.U. 12-25, at 320; Fitchburg Gas and Electric Light Company, D.P.U. 11-01/11-02, at 291-292 (2011); Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 118, 120 (2009); Bay State Gas Company, D.P.U. 92-111, at 124 (1993).

⁷ The Department determined that Eversource properly supported its proposed service lives and survivor curves and, therefore, accepted the proposed life and survivor curves. D.P.U. 17-05, at 201. These issues are not implicated by Eversource's Motion.

⁸ We note both Eversource and the Attorney General recognized and considered various depreciation principles set forth in Depreciation Systems, as well as those discussed in the Public Utility Depreciation Practices Manual compiled and edited by the National Association of Regulatory Utility Commissioners (see, e.g., Exhs. ES-JJS-Rebuttal at 30-36, AG-WWD-1, at 6, 9, 19, 24, 37; AG-WWD-Surrebuttal-1, at 1-5, 14-16;

accounts, it would accept the Attorney General's proposed net salvage factors in determining Eversource's depreciation accrual rates. D.P.U. 17-05, at 209.

After review of Eversource's Motion and the Attorney General's Opposition, the Department is now persuaded that it erred in evaluating Eversource's and the Attorney General's respective proposed salvage analyses. In particular, as explained further below, we conclude that the Eversource's method of deriving net salvage values was appropriate and, in this instance, should have been accepted. Accordingly, we find that reconsideration of the decision in D.P.U. 17-05 with respect to net salvage is necessary and appropriate. D.P.U. 96-50-C (Phase I) at 22; D.P.U. 86-33-J at 2, 25-26; D.P.U. 1350-A at 5.

4. Reconsideration

With respect to net salvage, the aforementioned instruction from Depreciation Systems that "[a] first step in salvage analysis is to convert the observed dollars to constant dollars," is just one step in the particular forecasting method that the authors use to calculate future salvage factors (or future salvage ratios) (see Exhs. AG-WWD-Surrebuttal-2; ES-1). The instruction is part of the introductory chapter on net salvage ("Chapter 4"), which describes the basic concepts of salvage and the preliminary analysis recommended before a depreciation analyst forecasts any future salvage ratios (Exh. AG-WWD-Surrebuttal-2). While it is clear that the preliminary analysis requires first converting observed dollars to constant dollars, it stands to reason that if conversion to constant dollars is the "first step" in salvage analysis, then additional steps follow. Indeed, the sentence immediately following the conversion instruction provides "[t]hen the constant dollar

AG-WWD-Surrebuttal-2). The Department likewise recognizes the principles set forth in these leading depreciation texts. See D.P.U. 17-05, at 203-205, 208.

salvage curves can be examined and fit to a model,” which indicates that the analyst will examine these constant dollar salvage curves and fit them to one of several basic models that represents the functional relationship between that group of assets’ ages at retirement and their corresponding salvage values (Exh. AG-WWD-2, at 4, 8). Thus, we find that a more contextualized reading of the conversion to constant dollars instruction is that it is a component of the preliminary analysis that supports the identification of the underlying age and salvage relationship that may be obscured by inflation (Exh. AG-WWD-2, at 4, 8). In fact, the full forecasting method is not described in Chapter 4 at all (see Exhs. AG-WWD-Surrebuttal 2; ES-1). Rather, Depreciation Systems provides a full method of forecasting future salvage ratios in a later chapter of the treatise (“Chapter 14”) (Exh. ES-1).

In Chapter 14 of Depreciation Systems the full forecasting method begins with an examination of the data reflecting the total annual costs (Exh. ES-1, at 4). In order to develop a preliminary model describing the relationship between asset age and salvage, the text encourages the depreciation analyst to become familiar with the physical characteristics of the property in each account and with the manner of retiring the property (Exh. ES-1, at 5). Similar to the caveats noted in Chapter 4, the full forecasting method set forth in Chapter 14 cautions that because inflation may obscure patterns, it may be helpful to analyze the salvage curves using a constant price level (Exh. ES-1, at 5). Next, the analyst uses judgement and outside information to decide whether or not the model chosen for the historical data can be used to forecast future salvage values by evaluating the likelihood that the method of retirement will remain the same for the assets currently in service (Exh. ES-1, at 6). Finally, the analyst uses the chosen model to forecast

future salvage values using three parameters, one of which is the annual rate of inflation (Exh. ES-1, at 6). Thus, it is clear that the final salvage ratios developed using the methods described in Depreciation Systems include inflation.

In this proceeding, it is not clear, however, that Eversource used this full method because the workpapers include only the observed data and do not include the constant dollar analysis, choice of preliminary models, or creation of forecasts necessary to employ the full method described above (Exhs. ES-JJS-2, at 38-41, 149-175; ES-JJS-3, at 38-41, 125-145). Additionally, Eversource's depreciation witness indicated that the Companies' net salvage percentages are estimated using only the actual historical data through 2015, along with the witness' consideration of industry experience (Exhs. ES-JJS-1, at 12-13; AG-6-17).

Nevertheless, we recognize that the Public Utility Depreciation Practices Manual compiled and edited by the National Association of Regulatory Utility Commissioners ("NARUC") manual describes an abbreviated method of forecasting salvage ratios, which foregoes the removal and subsequent reintroduction of inflation required for a more robust analysis and forecast (see RR-DPU-26). Similar to Depreciation Systems, NARUC indicates that the process of estimating future net salvage starts by analyzing past salvage data and using the results of that analysis to project future salvage values (RR-DPU-26, at 157-158). NARUC instructs the depreciation analyst to determine the past relationship of net salvage as a percent of retirements, using observed nominal values for net salvage and installation data that inherently include the effects of inflation because the two data points represent different points in time (RR-DPU-26, at 158-159). NARUC then details several technical considerations in using the results of the

historical data to project future salvage values, including anticipated changes in retirement methods, company policy, environmental regulations, and future prices of scrap and labor (RR-DPU-26, at 159). NARUC acknowledges that this second step involves considerable cost, time, and effort, and is often the subject of controversy (RR-DPU-26, at 157). Thus, NARUC concludes that, for most companies, detailed analyses and forecasts are not economically justifiable (RR-DPU-26, at 158-159). Additionally, NARUC concludes that a depreciation analyst, cognizant of the factors that may cause future experience to differ from that of the past, should be able to adequately estimate future salvage as a percent of retirements by applying informed judgment to modify the results of historical analyses (RR-DPU-26, at 161).

Based on a review of Eversource's depreciation studies, the Department finds that Eversource's salvage analysis is consistent with the analysis prescribed by NARUC (Exhs. ES-JJS-1, at 12-13; ES-JJS-2, at 38-41, 149-175; ES-JJS-3, at 38-41, 125-145; see also RR-DPU-26, at 157-164). Further, we find that this method is consistent with previously accepted approaches of determining net salvage factors. See, e.g., Bay State Gas Company, D.P.U. 12-25, at 307, 312 (2012); D.P.U. 1350, at 97, 107-111. Given that the method set forth in Depreciation Systems and the one prescribed by NARUC both recognize an inflation component, the Department no longer is persuaded that Eversource's failure to discount its salvage values for the time value of money resulted in proposed net salvage factors that overstate the Companies' salvage costs and produce excessive depreciation accrual rates. Rather, we find that for the 14 subject accounts, Eversource's proposed net salvage factors appropriately recognize the full service value of the assets in these accounts. While it is true that Eversource's net salvage factors result in

higher depreciation rates than those proposed by the Attorney General, we find that the rates, which were calculated according to an acceptable method, are appropriate to ensure that current customers who receive service from those particular assets pay for an appropriate share of the costs for retiring those assets. Therefore, the proposed net salvage factors should have been approved in D.P.U. 17-05.

Additionally, upon further reconsideration, the Department finds that the Attorney General's alternative proposed net salvage factors should not have been adopted. Although the Attorney General was not required to submit her own depreciation study, she was required to provide appropriate support for her alternative net salvage factors. The Department notes that, while the Attorney General objected to the inclusion of inflation in the final salvage factors, her proposed remedy did not remove inflation, but instead simply reduced the net salvage for the 14 subject accounts to arrive at net salvage accruals to a level that was 2.2 times larger than a recent average annual net salvage expense (Exhs. AG-WWD-1, at 14, 28; AG-WWD-4; Tr. 9, at 1757). The Attorney General based this proposal on the objective of creating a "reasonable relationship" between the depreciation accrual for net salvage that is charged to the ratepayers compared to what the Companies actually incur for net salvage (Exh. AG-WWD-1, at 26, 32; Tr. 9, at 1758-1760). Notwithstanding the findings in D.P.U. 17-05, at 209, however, upon reconsideration we conclude that other than demonstrating that her alternative represents a gradual decrease from the Companies' proposed accruals, the Attorney General offered no persuasive explanation why net salvage accruals that are 2.2 times larger than a recent average annual net salvage expense are more appropriate than the Companies' proposal or appropriate on their own merit.

(Exhs. AG-WWD-1, at 14, 28; DPU-AG-2-14; Tr. 9, at 1757-1760). While we recognize that, in contrast to the selection of average service lives and dispersion curves, the selection of salvage values is more subjective, the Department is not prepared to deviate from a recognized and accepted approach to deriving salvage ratios in the absence of an appropriately supported alternative. In this case, upon reconsideration, we are not persuaded that the Attorney General's alternative approach is sufficiently reliable to warrant a departure from the approach used by Eversource. Moreover, as noted above, we find that the overall depreciation rates proposed by Eversource are appropriate and not excessive.

Based on these findings, we conclude that Eversource's proposed net salvage factors for NSTAR Electric's accounts 366, 367, 369.1, 369.2, and 373, and WMECo's accounts 362, 364, 365, 366, 367, 369.1, 369.2, 370, and 371, are acceptable. In D.P.U. 17-05, at 201, the Department determined that Eversource properly supported its proposed service lives and survivor curves and, therefore, accepted the proposed life and survivor curves. Accordingly, the Department approves Eversource's proposed depreciation rates.

5. Other Issues

As noted above in Section II.A, on January 19, 2018, Eversource filed a Motion for Leave and a Response to the Attorney General's Opposition. For the first time in this proceeding, Eversource argued that the Attorney General's proposed depreciation accrual rates cannot be disaggregated into "valid and proper components" necessary to perform the financial accounting procedures required by Eversource's accountants (Response at 2-3, 7-9, 18). In light of our findings above, we need not reach the merits of this argument.

Notwithstanding our decision here, however, we again stress that the Department has routinely adjusted net salvage factors without the need to disaggregate net salvage in the manner apparently sought by Eversource. D.P.U. 14-150, at 190, 195; D.P.U. 12-25, at 316-318, 323; D.P.U. 09-39, at 197; D.P.U. 08-27, at 116; D.T.E. 02-24/25, at 136-137, 139, 142; D.P.U. 92-250, at 68, 70. Eversource's own depreciation studies determine salvage factors in part based on the witness's own expertise and informed judgement, and do not disaggregate net salvage by various components (Exhs. ES-JJS-1, at 8, 13; ES-JJS-2, at 39-41; ES-JJS-3, at 39-41). Given this reliance on informed judgment, we are not persuaded that a depreciation study's salvage factors can be disaggregated into the level of detail that Eversource purports is necessary to maintain its financial records.⁹ Further, no company has previously raised the financial accounting issues raised by Eversource in this proceeding, and none has previously expressed any inability to calculate depreciation expense as a result of revised depreciation accrual rates.¹⁰ Finally, the Companies' concerns over financial accounting issues were, or should have been, known to Eversource at least as early as April 28, 2017, when the Attorney General filed direct testimony and presented her net salvage analysis (Exhs. AG-WWD-1; AG-WWD-3; AG-WWD-4). Despite this timely notice, however, Eversource failed to raise its concerns in discovery, rebuttal

⁹ If a depreciation study did offer these types of disaggregation, it would be reasonable to conclude that the result of the study would be suspect.

¹⁰ In any event, the Department has long considered that neither financial nor tax accounting standards automatically dictate ratemaking treatment. Boston Edison Company, D.P.U./D.T.E. 97-95, at 76-77 (2001); Massachusetts-American Water Company, D.P.U. 95-118, at 107 (1996); NYNEX Price Cap, D.P.U. 94-50, at 305 (1995); Massachusetts Electric Company, D.P.U. 92-78, at 79 80 (1992); Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979).

testimony, during the evidentiary hearings, or on brief. Instead, Eversource first raised the financial accounting issue after the Department issued its order in D.P.U. 17-05, in the form of the Motion for Leave. The Department expects all parties to raise all relevant arguments upon which they may rely as they reasonably become known during the course of the evidentiary phase of the proceedings. Parties who fail to do so face the risk of having such arguments being deemed untimely and excluded from Department consideration.

6. Conclusion

In order to calculate Eversource's annual depreciation expense based on the Companies' accrual rates, the Department has applied those accrual rates to the Companies' depreciable plant balances included in rate base. As discussed in D.P.U. 17-05, at 211-212, the Department allowed the inclusion of NSTAR Electric's proposed post-test year plant additions, but excluded \$3,335,790 in post-test year additions associated with WMECo's Montague substation upgrades. Finally, the Department reduced NSTAR Electric's amortization reserve deficiency adjustment from the proposed \$128,698 to \$80,436, and reduced WMECo's amortization reserve deficiency adjustment from the proposed \$475,881 to \$297,051. Based on this analysis, and in light of the findings above, the Department finds that NSTAR Electric's annual depreciation and amortization expense is \$152,178,892, and WMECo's annual depreciation and amortization expense is \$29,651,434. Accordingly, NSTAR Electric's depreciation and amortization expense as approved in D.P.U. 17-05 shall be increased by \$6,552,141, and WMECo's depreciation and amortization expense as approved in D.P.U. 17-05 shall be increased by \$2,666,988. The effect of these findings is set forth in the Schedules below.

III. SCHEDULES – NSTAR ELECTRIC COMPANY¹¹

A. Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

SCHEDULE 1 - NSTAR ELECTRIC COMPANY

REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	322,597,077	222,884	(26,164,877)	296,655,084
Depreciation & Amortization	176,196,744	(3,043,199)	(57,513)	173,096,032
Taxes Other Than Income Taxes	99,430,889	1,185,985	(27,485)	100,589,389
Income Taxes	106,987,033	367,042	(49,564,198)	57,789,877
Return on Rate Base	208,211,099	(5,049,088)	(2,907,279)	200,254,732
Additional Uncollectibles (Revenue Deficiency)	426,407	(29,016)	(581,845)	(184,454)
Total Cost of Service	913,849,249	(6,345,392)	(79,303,197)	828,200,660
OPERATING REVENUES				
Base Distribution Revenues	829,692,282	0	0	829,692,282
Other Operating Revenues	23,962,582	631,625	(47,112)	24,547,095
Total Operating Revenues	853,654,864	631,625	(47,112)	854,239,377
Total Revenue Deficiency	60,194,385	(6,977,017)	(79,256,085)	(26,038,717)

¹¹ Numbers may not add due to rounding, and any minor discrepancies between the numbers in the Schedules and those in the text are due to rounding.

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	274,358,971	(470,430)	2,409,293	276,297,834
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Postage Expense	(126,159)	0	0	(126,159)
Uncollectible Expense	(3,573,684)	0	0	(3,573,684)
Fee Free Payment Processing	5,093,091	0	(5,093,091)	0
Fee Free Offset	0	0	52,891	52,891
Dues and Memberships	(93,080)	0	0	(93,080)
Employee Benefits Costs	1,548,219	1,104,330	(323,914)	2,328,635
Insurance Expense And Injuries & Damages	(87,075)	0	0	(87,075)
Payroll Expense	10,035,441	(964,281)	0	9,071,160
Variable Compensation	(3,057,252)	(91,433)	(460,042)	(3,608,727)
Vegetation Expense Annualization	5,226,646	0	0	5,226,646
Vegetation Management Resiliency Tree Work Pilot	22,752,025	0	(22,752,025)	0
Rate Case Expense	471,976	153,383	(29,052)	596,307
Regulatory Assessments	(2,188,739)	455,947	2,409,292	676,500
Lease Expense	400,375	219,956	(154,496)	465,835
Information Systems Expense Adjustment	1,362,605	(114,437)	(1,248,168)	0
GIS Verification Adjustment	1,023,615	167,661	(1,191,276)	0
Storm Cost Adjustment	2,880,000	0	0	2,880,000
Storm Fund Adjustment	3,500,000	0	0	3,500,000
Eversource Service Company Charges	0	0	(3,778)	(3,778)
Insurance Policy Distribution	0	0	(158,407)	(158,407)
Residual O&M Inflation Adjustment	3,070,102	(237,812)	377,896	3,210,186
Sum of O&M Expense Adjustments	48,238,106	693,314	(28,574,170)	20,357,250
Total O&M Expense	322,597,077	222,884	(26,164,877)	296,655,084

C. Schedule 3 – Depreciation and Amortization Expenses**SCHEDULE 3 - NSTAR ELECTRIC COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES**

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	152,153,130	74,023	(48,261)	152,178,892
Amortization of Deferred Assets	24,043,614	(3,117,222)	(9,252)	20,917,140
Total Depreciation and Amortization Expense	176,196,744	(3,043,199)	(57,513)	173,096,032

D. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	5,277,871,546	5,236,686	0	5,283,108,232
LESS:				
Reserve for Depreciation	1,629,791,051	1,250,000	2,351,645	1,633,392,696
Reserve for Amortization	21,408,453	0	0	21,408,453
Net Utility Plant in Service	3,626,672,042	3,986,686	(2,351,645)	3,628,307,083
ADDITIONS TO PLANT:				
Cash Working Capital	37,453,650	128,535	(2,389,605)	35,192,581
ASC 740 (net)	60,537,693	0	0	60,537,693
Materials and Supplies	34,922,056	0	0	34,922,056
Total Additions to Plant	132,913,399	128,535	(2,389,605)	130,652,330
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	984,178,132	669,989	0	984,848,121
Customer Deposits	6,369,673	0	0	6,369,673
Customer Advances	34,634,865	0	0	34,634,865
Total Deductions from Plant	1,025,182,670	669,989	0	1,025,852,659
RATE BASE	2,734,402,771	3,445,232	(4,741,250)	2,733,106,754
COST OF CAPITAL	7.61%	-0.19%	-0.09%	7.33%
RETURN ON RATE BASE	208,211,099	(5,049,088)	(2,907,279)	200,254,732

E. Schedule 5 – Cost of Capital

PER COMPANY				
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	\$2,100,000,000	45.69%	4.31%	1.97%
Preferred Stock	\$43,000,000	0.94%	4.56%	0.04%
Common Equity	\$2,452,820,959	53.37%	10.50%	5.60%
Total Capital	\$4,595,820,959	100.00%		7.61%
Weighted Cost of Debt				1.97%
Preferred				0.04%
Equity				5.60%
Cost of Capital				7.61%

COMPANY ADJUSTMENTS				
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	\$2,100,000,000	45.69%	3.88%	1.77%
Preferred Stock	\$43,000,000	0.94%	4.56%	0.04%
Common Equity	\$2,452,820,959	53.37%	10.50%	5.60%
Total Capital	\$4,595,820,959	100.00%		7.42%
Weighted Cost of Debt				1.77%
Preferred				0.04%
Equity				5.60%
Cost of Capital				7.42%

PER ORDER				
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	\$2,100,000,000	45.72%	4.27%	1.95%
Preferred Stock	\$43,000,000	0.94%	4.56%	0.04%
Common Equity	\$2,450,093,895	53.34%	10.00%	5.33%
Total Capital	\$4,593,093,895	100.00%		7.33%
Weighted Cost of Debt				1.95%
Preferred				0.04%
Equity				5.33%
Cost of Capital				7.33%

F. Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense	322,597,077	222,884	(26,164,877)	296,655,084
Less Uncollectible Accounts	11,499,968	0	0	11,499,968
Taxes Other Than Income	99,430,890	1,185,985	(27,485)	100,589,390
Total Costs Subject to Cash Working Capital	410,527,999	1,408,869	(26,192,362)	385,744,506
Cash Working Capital Factor (33.30/365)	9.12%	9.12%	9.12%	9.12%
Total Cash Working Capital Allowance	37,453,650	128,535	(2,389,605)	35,192,581

G. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA	6,686,097	(49,763)	(27,485)	6,608,849
Medicare	1,806,639	(13,446)	0	1,793,193
Federal Unemployment	45,739	0	0	45,739
State Unemployment	259,370	0	0	259,370
State Insurance Premium Excise Tax	230,381	0	0	230,381
Tangible Property Tax	1,275,000	0	0	1,275,000
Universal Health Tax	40,372	0	0	40,372
State Sales and Use Tax	3,918	0	0	3,918
Property Tax	89,083,373	1,249,194	0	90,332,567
Taxes Other Than Income	99,430,889	1,185,985	(27,485)	100,589,389

H. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	2,734,402,771	3,445,232	(4,741,250)	2,733,106,754
Return on Rate Base	208,211,099	(5,049,088)	(2,907,279)	200,254,732
Interest Expense	(53,813,047)	5,243,623	(4,753,489)	(53,322,913)
Amortization of Net Unfunded Deferred Tax Liab.	1,488,887	0	0	1,488,887
Income Tax Impact of Flowthrough Items	1,311,689	0	0	1,311,689
FAS 109 Income Taxes and ITC	0	141,288	0	141,288
Total Deductions	(51,012,471)	5,384,911	(4,753,489)	(50,381,049)
Taxable Income Base	157,198,628	335,823	(7,660,768)	149,873,683
Gross Up Factor	1.6722	1.6722	1.3759	1.3759
Taxable Income	262,873,992	561,577	(57,224,368)	206,211,201
Mass Franchise Tax (8%)	21,029,919	44,926	(4,577,949)	16,496,896
Federal Taxable Income	241,844,072	516,651	(52,646,419)	189,714,305
Federal Income Tax (21%)	84,645,425	180,828	(44,986,249)	39,840,004
Income Tax Impact of Flowthrough Items	1,311,689	0	0	1,311,689
FAS 109 Income Taxes and ITC	0	141,288	0	141,288
Total Income Taxes	106,987,033	367,042	(49,564,198)	57,789,877

I. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
DISTRIBUTION REVENUES PER BOOKS	829,692,282	69,143	0	829,761,425
Other Operating Revenues	29,548,876	0	0	29,548,876
<u>Other Operating Revenues</u>				
Special Contracts	217,639	0	0	217,639
Late Payment Charges	3,437,879	0	0	3,437,879
Rent from Electric Property	8,322,192	689,974	577,328	9,589,494
Other Electric Revenue	11,648,697	208,683	(624,440)	11,232,940
Revenues from Transmission of Electricity of Others	336,175	(336,175)	0	0
Total Other Revenues	23,962,582	562,482	(47,112)	24,477,952
Adjusted Total Operating Revenues	853,654,864	631,625	(47,112)	854,239,377

IV. SCHEDULES – WESTERN MASSACHUSETTS ELECTRIC COMPANY¹²A. Schedule 1 – Revenue Requirements and Calculation of Revenue Increase**SCHEDULE 1 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE**

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	67,567,718	82,708	(4,469,293)	63,181,133
Depreciation & Amortization	32,781,024	(1,164,091)	(582,650)	31,034,283
Taxes Other Than Income Taxes	18,259,052	948,871	(35,148)	19,172,775
Income Taxes	19,459,290	(46,295)	(8,725,828)	10,687,167
Return on Rate Base	33,576,776	(597,919)	(1,312,364)	31,666,493
Additional Uncollectibles (Revenue Deficiency)	443,454	(12,264)	(185,927)	245,263
Total Cost of Service	172,087,313	(788,990)	(15,311,210)	155,987,114
OPERATING REVENUES				
Base Distribution Revenues	132,415,741	0	0	132,415,741
Other Operating Revenues	4,008,528	197,255	(358,726)	3,847,057
Total Operating Revenues	136,424,269	197,255	(358,726)	136,262,798
Total Revenue Deficiency	35,663,044	(986,245)	(14,952,484)	19,724,316

¹²

Numbers may not add due to rounding, and any minor discrepancies between the numbers in the Schedules and those in the text are due to rounding.

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	\$59,918,641	(\$159,997)	\$413,176	\$60,171,820
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Postage Expense	(27,580)	0	0	(27,580)
Uncollectible Expense	(2,063,199)	0	0	(2,063,199)
Fee Free Payment Processing	906,909	0	(906,909)	0
Fee Free Payment Processing O&M Savings Offset	0	0	9,378	9,378
Dues and Memberships	(2,693)	0	0	(2,693)
Employee Benefits Costs	206,047	205,993	(24,483)	387,557
Insurance Expense and Injuries & Damage	(110,172)	0	0	(110,172)
Payroll Expense	1,694,639	0	(173,600)	1,521,039
Variable Compensation	(714,682)	0	(85,221)	(799,903)
Vegetation Management Resiliency Tree Work Pilot	3,902,175	0	(3,902,175)	0
Rate Case Expense	311,279	37,027	(5,127)	343,179
Regulatory Assessments	(374,453)	80,051	413,176	118,774
Lease Expense	13,819	0	(27,167)	(13,348)
Information Systems Expense Adjustment	244,633	(6,696)	(237,937)	(0)
Storm Cost Adjustment	720,000	0	0	720,000
Storm Fund Adjustment	2,000,000	0	0	2,000,000
Eversource Service Company Charges	0	0	(662)	(662)
Insurance Policy Distribution	0	0	(22,675)	(22,675)
Residual O&M Inflation Adjustment	942,355	(73,669)	80,933	949,619
Sum of O&M Expense Adjustments	7,649,077	242,705	(4,882,469)	3,009,313
Total O&M Expense	67,567,718	82,708	(4,469,293)	63,181,133

C. Schedule 3 – Depreciation and Amortization Expenses**SCHEDULE 3 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES**

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	30,276,615	(44,091)	(581,090)	29,651,434
Amortization of Deferred Assets	2,504,409	(1,120,000)	(1,560)	1,382,849
Total Depreciation and Amortization Expense	32,781,024	(1,164,091)	(582,650)	31,034,283

D. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	834,673,665	(1,586,025)	(3,488,926)	829,598,714
LESS:				
Reserve for Depreciation	232,345,474	(6,919)	0	232,338,555
Reserve for Amortization	19,245,859	0	0	19,245,859
Net Utility Plant in Service	583,082,332	(1,579,106)	(3,488,926)	578,014,300
ADDITIONS TO PLANT:				
Cash Working Capital	7,547,362	94,114	(407,746)	7,233,729
ASC 740 (net)	19,209,890	0	0	19,209,890
Materials and Supplies	2,242,787	0	0	2,242,787
Total Additions to Plant	29,000,039	94,114	(407,746)	28,686,406
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	168,804,718	(255,350)	(672,829)	167,876,539
Customer Deposits	2,114,715	0	0	2,114,715
Customer Advances	291,410	0	0	291,410
Total Deductions from Plant	171,210,843	(255,350)	(672,829)	170,282,664
RATE BASE	440,871,528	(1,229,642)	(3,223,843)	436,418,042
COST OF CAPITAL	7.62%	-0.11%	-0.25%	7.26%
RETURN ON RATE BASE	33,576,776	(597,919)	(1,312,364)	31,666,493

E. Schedule 5 – Cost of Capital

PER COMPANY				
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	\$547,975,604	46.66%	4.32%	2.02 %
Preferred Stock	\$0	0.00%	0.00%	0.00 %
Common Equity	\$626,410,414	53.34%	10.50%	5.60 %
Total Capital	\$1,174,386,018	100.00%		7.62 %
Weighted Cost of				
Debt				2.02 %
Preferred				0.00 %
Equity				5.60 %
Cost of Capital				7.62 %

COMPANY ADJUSTMENTS				
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	\$547,975,604	46.66%	4.07%	1.90 %
Preferred Stock	\$0	0.00%	0.00%	0.00 %
Common Equity	\$626,410,414	53.34%	10.50%	5.60 %
Total Capital	\$1,174,386,018	100.00%		7.50 %
Weighted Cost of				
Debt				1.90 %
Preferred				0.00 %
Equity				5.60 %
Cost of Capital				7.50 %

PER ORDER				
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	\$547,975,604	45.49%	3.97%	1.81 %
Preferred Stock	\$0	0.00%	0.00%	0.00 %
Common Equity	\$656,686,129	54.51%	10.00%	5.45 %
Total Capital	\$1,204,661,733	100.00%		7.26 %
Weighted Cost of				
Debt				1.81 %
Preferred				0.00 %
Equity				5.45 %
Cost of Capital				7.26 %

F. Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA	1,294,826	0	(17,574)	1,277,252
Medicare	356,766	0	0	356,766
Federal Unemployment	10,015	0	0	10,015
State Unemployment	63,080	0	(17,574)	45,506
State Insurance Premium Excise Tax	30,003	0	0	30,003
Federal Highway Tax	1,610	0	0	1,610
Universal Health Tax	8,203	0	0	8,203
State Sales and Use Tax/Other	942	0	0	942
Property Tax	16,493,608	948,871	0	17,442,479
Taxes Other Than Income	18,259,052	948,871	(35,148)	19,172,775

G. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA	1,294,826	0	(17,574)	1,277,252
Medicare	356,766	0	0	356,766
Federal Unemployment	10,015	0	0	10,015
State Unemployment	63,080	0	(17,574)	45,506
State Insurance Premium Excise Tax	30,003	0	0	30,003
Federal Highway Tax	1,610	0	0	1,610
Universal Health Tax	8,203	0	0	8,203
State Sales and Use Tax/Other	942	0	0	942
Property Tax	16,493,608	948,871	0	17,442,479
Taxes Other Than Income	18,259,052	948,871	(35,148)	19,172,775

H. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	440,871,529	(1,229,642)	(3,223,843)	436,418,042
Return on Rate Base	33,576,776	(597,919)	(1,312,364)	31,666,493
Add: Flow-Through and Permanent Items	3,815,783	0	0	3,815,783
Less: Interest Expense	(8,885,325)	529,051	478,928	(7,877,346)
Add: FAS 109 Income Taxes and ITC	176,747	0	49,019	225,766
Total Deductions	(4,892,795)	529,051	527,947	(3,835,797)
Taxable Income Base	28,683,981	(68,867)	(784,417)	27,830,696
Gross Up Factor	1.672241	1.672241	1.375894	1.375894
Taxable Income	47,966,524	(115,163)	(9,559,263)	38,292,098
Massachusetts Income Tax (8%)	3,837,322	(9,213)	(764,741)	3,063,368
Federal Taxable Income	44,129,202	(105,950)	(8,794,522)	35,228,730
Federal Income Tax Calculated (21%)	15,445,221	(37,082)	(8,010,106)	7,398,033
Total Income Taxes Calculated	19,282,543	(46,295)	(8,774,847)	10,461,401
Add: FAS 109 Income Taxes and ITC	176,747	0	49,019	225,766
Total Income Taxes	19,459,290	(46,295)	(8,725,828)	10,687,167

I. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
<u>Distribution Revenues</u>				
Distribution Revenues	132,218,977	0	(464,646)	131,754,331
Revenue Decoupling (Prior Year Refund)	(5,104,988)	0	0	(5,104,988)
Revenue Decoupling	5,301,752	0	464,646	5,766,398
Total Distribution Revenues	132,415,741	0	0	132,415,741
<u>Other Revenues</u>				
Sales for Resale (447)	55,380	0	0	55,380
Late Payment Charges (450)	526,847	(238,893)		287,954
Misc. Revenues (451)	246,414	436,148	(358,726)	323,836
Rent from Electric Property (454)	800,581	0		800,581
Other Electric Revenue (456)	2,379,306	0	0	2,379,306
Total Other Revenues	4,008,528	197,255	(358,726)	3,847,057
Adjusted Total Operating Revenues	136,424,269	197,255	(358,726)	136,262,798

V. ORDER

Accordingly, after due notice, opportunity for comment and consideration, it is

ORDERED: That NSTAR Electric Company d/b/a Eversource Energy's Motion for Reconsideration is GRANTED; and it is

FURTHER ORDERED: That the revenue requirement for NSTAR Electric Company is set at (\$26,038,717); and it is

FURTHER ORDERED: That the revenue requirement for Western Massachusetts Electric Company is set at \$19,724,316; and it is

FURTHER ORDERED: That NSTAR Electric Company, d/b/a Eversource Energy shall files revised schedules of rates and charges based on the combined revenue requirements set herein; and it is

FURTHER ORDERED: That NSTAR Electric Company d/b/a Eversource Energy shall comply with all other orders and directives contained in this Order.

By Order of the Department,

/s/

Angela M. O'Connor, Chairman

/s/

Robert E. Hayden, Commissioner

/s/

Cecile M. Fraser, Commissioner

A: I think I know, but I really think I need to refer you to Keith Pruett our accounting guy that will be able to really answer that question.

Q: But to your knowledge, no adjustments were made to Oncor—to the Capgemini figures in preparing its application for this case?

A: Rephrase that question, I –

Q: Oncor has made no adjustment to its Capgemini costs in preparing its application in this case.

A: Not that I'm aware of. But you will need to talk to Keith Pruett, our accounting witness, on the treatment of—on that \$88 million.

Q: And just so –

A: As I understand it, those disputed charges are not in the \$88 million generally. There may be a very small amount, but generally that disputed charge is not in the \$88 million as I understand it, but Keith Pruett is the guy you need to talk to.⁴¹⁵

Cities asserted that Oncor could not accurately determine whether the \$88 million contained disputed matters. Cities pointed out that Oncor did not perform an audit of the CGE charges. Moreover, Mr. Pruett testified that the \$88 million was merely the amount billed by CGE during the test year with no *pro forma* adjustments other than the removal of approximately \$1 million of unrecoverable legislative and political activities:

Q: Do the numbers reflected in Oncor's Rate Filing Package for Capgemini expenses, do they reflect the amount of charges actually paid or the amount that were billed?

A: The amount that would be reflected in the test year would be the total cost of service for a 12-month calendar year, which could include accrual of services that have been provided but not yet paid.⁴¹⁶

⁴¹⁵ Tr. Vol. 4 at 638 (Jan. 16, 2009); Oncor Initial Brief at 116.

⁴¹⁶ Cities Reply Brief at 43; Tr. Vol. 5 at 748-50 (Jan. 21, 2009).

The ALJs do not agree with the Cities that Oncor's governance of the CGE contract was inadequate. The existence of problems with the contract or CGE's performance, as set out in both Cities Exs. 31 and 7A, does not mean that Oncor was unable to manage the contract effectively. The ALJs found Mr. Smith persuasive on this score, particularly in light of his considerable experience and Mr. Nalepa's lack of experience in reviewing outsourcing arrangements.⁴¹⁷ Moreover, Mr. Nalepa's assertion that ARC and project costs should be limited to those of previous years was overly simplistic. As Mr. Smith testified, one would expect the charges over the baseline amounts to increase over the years. Mr. Carpenter explained that additional changes and improvements in IT systems caused increased expenses in 2007.⁴¹⁸ Mr. Nalepa did not identify any specific ARC or project costs that he deemed unreasonable.

Mr. Pruett's testimony left open the possibility that the \$88 million included some disputed charges, however. The Termination Agreement sets out the ARC and project charges disputed between Oncor and CGE. The net disputed ARC amounts for 2007, as set out in that agreement, were \$5,103,700.91. The net disputed project charges for 2007, as set out in that agreement, were \$509,504.99, for total disputed ARC and project charges for 2007 of \$5,673,205.90.⁴¹⁹ The ALJs find Oncor failed to prove the reasonableness of those charges, which should be disallowed from the approximately \$88 million request.

Cities also argued that the \$20 million Termination Payment and the \$4 million Transaction Credit to Oncor, which Oncor recorded on its book as goodwill, each should be disallowed over a four-year period (\$5 million and \$1 million per year), which the Cities estimated as a reasonable time between rate cases. The ALJs find no disallowance should be made for those payments. The Termination Payment was made to relieve CGE of its post-termination obligation to buy IT-related assets from Oncor. However, as Oncor pointed out, none of that investment was ever charged to the

⁴¹⁷ See Smith Direct, Oncor Ex. 14; Tr. Vol. 7 at 1146-48 (Jan. 23, 2009).

⁴¹⁸ Tr. Vol. 2 at 286 (Jan. 14, 2009); Carpenter Rebuttal, Oncor Ex. 40 at 6-9.

⁴¹⁹ The detailed amounts are set out in Cities Ex. 7A at 208. At the ALJs' request, and with the permission of CGE, Oncor waived the Highly Sensitive and Confidential designation for that page.

ratepayer and Oncor has not sought recovery of that investment.⁴²⁰ The Transaction Credit was a relief from Oncor paying a portion of the disputed charges to CGE, not a windfall to Oncor as portrayed by the Cities.⁴²¹

F. Energy Efficiency Expenses and Programs

PURA § 39.905⁴²² requires a utility to provide adequate amounts of monetary incentives to third-party energy efficiency service providers (EESP), who in turn market their services to customers through market-based standard offer programs (SOP) or market transformation programs (MTP). The EESPs supply and install the energy efficiency measures in customers' homes or businesses. According to Michael Stockard, Oncor's Director of Energy Efficiency, Oncor may not mandate what measures the EESP must install or the areas they must serve. Savings may be in the form of reductions in peak demand, energy usage, or both.

The Commission adopted rules to implement PURA § 39.905, including P.U.C. SUBST. R. 25.181, which specifies the quantity and types of energy efficiency that a utility must acquire each year. PURA and the Commission's rules establish an annual demand reduction goal of at least 15 %

⁴²⁰ Oncor Reply Brief at 71.

⁴²¹ Oncor Reply Brief at 71; Cities Ex. 7A (Confidential) at 161, 208.

⁴²² PURA 39.905(f) states:

(f) Unless funding is provided under Section 39.903, each unbundled transmission and distribution utility shall include in its energy efficiency plan a targeted low-income energy efficiency program as described by Section 39.903(f)(2), and the savings achieved by the program shall count toward the transmission and distribution utility's energy efficiency goal.

Section 39.903(f) states:

(f) Notwithstanding Section 39.106(b), the commission shall adopt rules regarding programs to assist low-income electric customers on the introduction of customer choice. The programs may not be targeted to areas served by municipally owned utilities or electric cooperatives that have not adopted customer choice. The programs shall include:

(1) reduced electric rates as provided by Subsections (h)-(l); and

of a utility's growth in demand by January 2009 and 20 % for January 2010. This goal is determined by using a weather-normalized, average historical growth of the most recent five years, with each subsequent year's goal recalculated, which means that the formula is a rolling average of the load growth for the most recent preceding five years.⁴²³

1. Low-Income Weatherization

Oncor requests approval of \$53,578,615 in costs necessary to maintain Oncor's energy efficiency programs, as well as a recovery factor to "true-up" yearly its actual costs. In 2007 Oncor offered 12 SOP and MTP energy efficiency programs. Oncor budgeted \$57,128,689 for the 2007 year and spent \$46,384,709. According to Michael Stockard, Oncor's minimum demand savings for 2007 was 75,500 kW. Oncor achieved 89,233 kW in demand reduction that year.⁴²⁴

Mr. Stockard explained that there were several reasons Oncor spent less than budgeted on the energy efficiency programs, but he pointed out that Oncor still exceeded its demand reduction goal. In addition, Oncor made a commitment in Docket No. 34077 that over the next five years it will spend at least \$100 million on demand-side management/energy efficiency programs above the amount approved by the Commission in Oncor's rates or through any energy efficiency cost recovery factor that might be approved.⁴²⁵

No one challenged that Oncor incurred the expenses requested. Instead, TLSC/TxRose objects to how Oncor is implementing the low-income weatherization programs and how it monitors these programs. In general, TLSC/TxRose asserts that Oncor's programs are not in compliance with federal and state laws or the Commission rules or prior orders; that Oncor is underperforming to the

(2) targeted energy efficiency programs to be administered by the Texas Department of Housing and Community Affairs in coordination with existing weatherization programs.

⁴²³ P.U.C. SUBST. R. 25.181(e)(1)(A).

⁴²⁴ Direct Testimony of Michael Stockard (Stockard Direct), Oncor Ex. 18 at 7, 8, 10.

⁴²⁵ Stockard Direct, Oncor Ex. 18 at 11, 20.

detriment of its low-income customers who qualified to participate in these programs; and that Oncor failed to give the programs proper oversight.

The ALJs find that Oncor's cost of service for the low-income weatherization program should be approved. The issues concerning Oncor's request for a cost recovery factor to recover energy efficiency expenses will be addressed in section VIII entitled Cost Allocation and Rate Design.

As for TLSC/TxRose's complaint that Oncor's low-income weatherization programs falls short of the mark on ensuring that program services are delivered to those in need, the ALJs agree with Oncor that these matters should be resolved in another forum. Nevertheless, in the event the Commission wants to decide these issues as part of the rate case, the ALJs will address them.

The low-income weatherization program was designed, in part, to retrofit the homes of eligible customers to make them more energy efficient. In Docket No. 34077, Oncor agreed to dedicate \$16 million over five years to low-income weatherization programs administered by the Texas Association of Community Action Agencies (TACAA) Weatherization Program for federally funded EESPs.⁴²⁶ TLSC/TxRose witness Carol Biedrzycki objected that Oncor was paying for this TACAA program from outside of its rates. It is not a part of Oncor's energy efficiency plan. She insisted the TACAA program should receive funding from both Oncor's rates and the agreement reached in Docket No. 34077.⁴²⁷

Oncor has two programs to target lower-income customers: the Pilot Targeted Low-Income Weatherization Program and the Pilot Targeted Partnership Low-income Weatherization Program. Frontier Associates LLC (Frontier) operates the Pilot Targeted Low-Income Weatherization Program

⁴²⁶ Direct Testimony of Carol Biedrzycki (Biedrzycki Direct), TLSC/TxRose Ex. 1 at 13. The Commission's Final Order in Docket No. 34077 states that TACAA "will administer \$3.2 million annually (for calendar years 2008 through 2012) for weatherization assistance services through local contracts with governmental and nonprofit agencies that will augment resources from the federal weatherization assistance program.

⁴²⁷ *Id.*

(Frontier's program). Oncor operates the Pilot Targeted Partnership Low-Income Weatherization Program (Oncor's program). Ms. Biedrzycki's opined that neither program meets the requirements of PURA or the Commission Substantive Rules for three reasons: (1) the programs are not part of the federally funded weatherization providers program; (2) the programs were not approved by the Commission; and (3) the Frontier program failed to provide energy efficiency benefits to its intended target.⁴²⁸

When the programs were first implemented, Oncor was required to provide \$3,412,941 to the Texas Department of Housing and Community Affairs (TDHCA) annually for operating the low-income weatherization program. Because TDHCA was unable to perform timely, Oncor reduced the funding allocated to TDHCA by the amount unspent through August 31, 2007, and redirected those funds to Frontier to meet the Senate Bill (SB) 712 weatherization program requirements.⁴²⁹ Frontier was responsible to enlist local community agencies' participation in the program.

TLSC/TxRose argues Oncor had no right to cancel a contract with TDHCA because there was no contract. Ms. Biedrzycki argued that because Oncor and TDHCA did not sign a contract, TDHCA could not have violated Paragraph 9.2 of that contract, the provision that allowed Oncor to redirect funds to Frontier.⁴³⁰ Consequently, she argued that Oncor had no right to transfer the SB 712 funds to the Frontier and Oncor programs, and therefore, both are invalid SB 712 programs.

TLSC/TxRose also contends that Oncor violated PURA § 39.905(f) because the Frontier program and Oncor program were not coordinated with the federal weatherization program. Reasoning that under PURA § 39.903(f) Oncor could only use energy efficiency programs administered by TDHCA, and TDHCA only administers federal weatherization programs, TLSC/TxRose concludes all providers had to be federal weatherization providers. Because the

⁴²⁸ Biedrzycki Direct, TLSC/TxRose Ex. 1 at 25.

⁴²⁹ See *Commission Staff's Application For Approval Of Plan To Implement Targeted Low-Income Energy-Efficiency Programs*, Docket No. 32103, Final Order (Aug. 9, 2006).

⁴³⁰ Biedrzycki Direct, TxRose Ex. 1 at 20.

Frontier program and Oncor program are open to any service provider, TLSC/TxRose contends the programs did not comply with PURA.⁴³¹

In response to that charge, Mr. Stockard pointed out that Oncor agreed in Docket No. 32103 to give \$3,412,941 annually to TDHCA to satisfy Oncor's SB 712 obligation.⁴³² But, on May 23, 2007, TDHCA notified Oncor that it could not spend the funds Oncor paid it because of a ruling by the Office of Public Accounts. TDHCA advised Oncor to make other arrangements that did not involve TDHCA. Oncor did so and ultimately contracted with Frontier for Frontier to administer its SB 712 program.⁴³³

TLSC/TxRose confirm in its brief that "TDHCA informed Oncor that it was legally unable to fulfill the role set forth for it in the agreement."⁴³⁴ TLSC/TxRose also agrees that the Commission found that T&D utilities could choose their own administrators for the low-income weatherization programs. Nevertheless, TLSC/TxRose claim that Oncor still failed to operate its SB 712 programs properly because Oncor contracted with non-federally-funded weatherization providers.

In addition, Ms. Biedrzycki argued that Oncor failed to get approval for these two programs as required by PURA § 39.905(d). Oncor contends that because these programs were part of the mandated energy efficiency program it was unnecessary to comply with PURA § 39.905(d). Ms. Biedrzycki countered that there is no exception to PURA § 39.905(d).

Explaining that on July 27, 2007, TLSC/TxRose filed a petition (Docket No. 34630)⁴³⁵ with the Commission seeking to have TACAA designated as the sole administrator for the SB 712

⁴³¹ Biedrzycki Direct, TxRose Ex. 1 at 18.

⁴³² *Commission Staff's Application for Approval of Plan to Implement Targeted Low-Income Energy-Efficiency Programs*, Docket No. 32103 (Aug. 9, 2006).

⁴³³ Rebuttal Testimony of Michael Stockard (Stockard Rebuttal), Oncor Ex. 44 at 6.

⁴³⁴ TLSC/TxRose Reply Brief at 4.

⁴³⁵ *Petition of Texas Legal Services Center and Texas Ratepayer's Organization to Save Energy to Modify the Commission's Final Order in Docket No. 32103 and to Reform the Agreement to Implement Weatherization Programs*, Docket No. 34630, Final Order (May 13, 2008).

programs for all unbundled utilities, including Oncor, Mr. Stockard complained that many of Ms. Biedrzycki's objections were already addressed by the Commission in Docket No. 34630 less than a year ago.⁴³⁶ The ALJs agree.

In that Order, the Commission found the following:

- Using a single statewide administrator for low-income weatherization programs in the past had not been entirely satisfactory. (FoF No. 31)
- Frontier's energy audit software may be easier for local weatherization agencies to use than the EASY audit system used by TACAA. (FoF No. 38)
- Allowing each utility to contract with an administrator of their own choosing for the targeted program in its service area promotes the legislative intent that targeted low-income energy efficiency plans be funded as a priority. (FoF No. 39)
- Because no funding for the targeted programs was provided pursuant to PURA § 39.903, PURA § 39.905(f) is in effect. (CoL No. 4)
- PURA § 39.903(f)(2) allows another entity besides TDHCA to receive and disburse funding for the targeted program. (CoL No. 9)
- "No single entity is best qualified to administer the targeted program in all service areas in coordination with the administration and reporting to be done by TDHCA." (CoL No. 10)

The Commission went on to state that it pre-approved the targeted low-income energy-efficiency program through its Order in Docket No. 32103. The May 13, 2008, Order also directed utilities that were not administering the targeted programs themselves to contract with an administrator within 90 days of the Order.⁴³⁷ Therefore, the ALJs find that TXSC/TxRose's objections discussed above are without merit.

⁴³⁶ Stockard Rebuttal, Oncor Ex. 44 at 6. Docket No. 34630, Final Order (May 13, 2008).

⁴³⁷ Stockard Rebuttal, Oncor Ex. 44 at Exhibit MRS-R-1 at 2 of 8. In Docket No. 34630, the Commission specifically found:

FoF No. 2. Before 2005, the Texas Department of Housing and Community Affairs (TDHCA administered a target energy efficiency program funded through the System benefit Fund (SBF).

According to TLSC/TxRose, the most troubling issue is that the Frontier program benefits was not being successfully provided to the low-income community. In support of this position, TLSC/TxRose notes that in 2007, Frontier only expended its start-up costs totaling \$50,000 on the Frontier program. In 2008, \$3 million was budgeted, but Frontier only spent \$223,248. Of this amount, \$20,295 was for administrative expenses. TLSC/TxRose argues that Frontier's low performance level meant low-income customers who needed these services were not receiving them.⁴³⁸

Meanwhile, the TACAA program was in full operation by June 2008, and within the first year it had delivered \$1.2 million in weatherization benefits to Oncor's low-income customers.⁴³⁹ TLSC/TxRose concludes that Oncor did not maximize the use of the weatherization program to ensure that the poorest population received the benefits under this program and did not properly monitor the programs or Oncor would have discovered the under-utilization of these programs.⁴⁴⁰

Finally, TLSC/TxRose claims that Oncor lacks proper oversight of the programs. Oncor is requesting \$53 million of program expenditures in 2009. Despite the magnitude funded, Oncor has no annual audits or program evaluations to ensure high standards are met. Ms. Biedrzycki admitted

FoF No. 3 Appropriations from the SBF for the targeted energy efficiency program were discontinued in 2005.

FoF No. 4 In 2005, the Texas Legislature adopted an amendment to PURA § 39.905 [Senate Bill (SB) 712] to fund the TDHCA targeted energy efficiency program through utility rates.

FoF No. 5 SB 712 requires transmission and distribution utilities (TDUs or utilities) who unbundled under PURA § 39.051 to have a targeted low-income energy weatherization plan.

FoF No. 12 Texas Association of Community Action Agencies (TACAA) is an association of community action agencies, which are funded in part by federal Community Services block grant, and each of which has its own board of directors. Other entities may also become members of TACAA; for instance, subrecipients of grants such as Sheltering Arms, Inc., a Houston-area provider of weatherization services. A majority of existing weatherization providers are members of TACAA.

FoF No. 27 Oncor has committed to contract with TACAA to administer Oncor's non-statutory low-income weatherization program for five years, with an annual budget of approximately \$3.2 million.

⁴³⁸ Biedrzycki Direct, TxRose Ex. 1 at 23.

⁴³⁹ *Id.*

⁴⁴⁰ Biedrzycki Direct, TxRose Ex. 1 at 8.

that such oversight is not required by the Commission, but insisted that meeting the standards set out in the Commission rules requires more controls than Oncor has in place.⁴⁴¹

The need for this program is not in question. The 2000 Census reported more than 489,000 Texas households live at or below the 50 % Federal Poverty Level, yet spend more than half their income for energy.⁴⁴² The issue before the ALJs is whether Oncor's 2007 low-income weatherization program expenses were necessary and reasonable and should be approved as a cost of service included in its rates.

The evidence presented shows that Oncor expended this amount. TLSC/TxRose objects to Oncor's lack of audits and oversight controls to confirm its EESPs have maximized the use of the programs for the benefit of the low-income customers. However, as Ms. Biedrzycki acknowledged, Oncor has no obligation to conduct such oversight under PURA or the Commission Rules. Since Frontier started administering the program late in 2007, it has made progress in implementing this program. Likewise, while it may be prudent to have more oversight in such a large program, there is no evidence that Oncor has failed to comply with the Commission's rules in monitoring the programs.

2. REAP

The Environmental Defense Fund (EDF) was the only entity to criticize Oncor's multi-family energy efficiency programs as ineffective. EDF wants Oncor to add to its energy efficiency programs its Reduce Energy in Apartments Program (REAP) and requests the ALJs to recommend its adoption. Alternatively, EDF wants the ALJs to recommend that Oncor be ordered to study the benefits of REAP with 4,000 to 5,000 multi-family units.⁴⁴³

⁴⁴¹ Biedrzycki Direct, TxRose Ex. 1 at 26-27.

⁴⁴² According to Ms. Biedrzycki, the lower-income households live in smaller homes, but consume 28 percent more energy per square foot because their homes are energy inefficient. Biedrzycki Direct, TxRose Ex. 1 at 10.

⁴⁴³ EDF's Reply Brief at 4.

Oncor disagrees that its multi-family energy efficiency programs have been ineffective. According to Oncor, from 2002 through 2007, a total of 199,095 residential customer premises participated in its Residential & Small Commercial and Hard to Reach SOPs. Of this amount, 42 % were multi-family apartments. Oncor points out that only 25 % of its residential customers are multi-family apartments. Oncor submits that these facts support its opinion that its multi-family apartment programs have been effective.”⁴⁴⁴

Oncor also raises the propriety of addressing this issue in its rate case because there are other energy efficiency stakeholders in this issue that are not participating in this rate case. Oncor asserts that the Commission and other energy efficiency stakeholders “would be better served if EDF’s REAP proposal were vetted through a rulemaking.”⁴⁴⁵

REAP is a new approach to achieving energy efficiency in apartments. EDF’s argument that PURA § 36.204 allows this issue to be addressed as part of Oncor’s rate case begs the question of notice. REAP was not included in Oncor’s application or RFP. Potential energy efficiency stakeholders who are not participating in this rate case have not received notice that the REAP issue will be addressed in this proceeding. Therefore, the ALJs recommend that the Commission consider EDF’s REAP in another forum and not as part of this rate case.

G. Depreciation Expense

Oncor seeks an increase of approximately \$87.2 million in its annual depreciation expense over existing rates.⁴⁴⁶ Three parties, Oncor, ATOC, and Staff, offered complete depreciation expense analyses. Two other parties, TIEC and Cities, offered testimony and recommendations regarding depreciation-related issues.

⁴⁴⁴ Stockard Rebuttal, Oncor Ex. 44 at 17-18.

⁴⁴⁵ Stockard Rebuttal, Oncor Ex. 44 at 17-18; Tr. Vol. 11 at 2212-2217 (Jan. 29, 2009).

⁴⁴⁶ Direct Testimony of Dane A. Watson (Watson Direct), Oncor Ex. 15 at 5; Supplemental Direct Testimony of Dane A. Watson (Watson Supplemental), Oncor Ex. 16 at 3; Pous Direct, ATOC Ex. 2 at 3.

Oncor witness Dane Watson acknowledged that Oncor was requesting a very significant increase in depreciation expenses. He testified, however, that Oncor's and its predecessors' depreciation rates had not been changed in fifteen years and that the net salvage component for Oncor's transmission assets had remained unchanged since 1976. He identified three main factors driving the proposed increase. First, an increase in the underlying cost of removing assets since the current net salvage rates were established had led to Oncor incurring removal costs for retiring assets that have not been recovered. Second, Oncor has not accrued toward future removal costs the dollars that would have been accrued since January 1, 2002, if the depreciation rates had been changed in Docket No. 22350 (TXU 2001 UCOS case). Third, the ongoing replacement of all existing meters with advanced meters had significantly changed the depreciation rate for those assets.⁴⁴⁷

Oncor allocated the cost of its assets on a straight-line basis over the service life of those assets, based on Mr. Watson's depreciation study and analysis. Mr. Watson testified his study fully supported setting Oncor's depreciation expense at the level he recommended.⁴⁴⁸

Both Jacob Pous, on behalf of ATOC, and Nara Srinivasa, on behalf of Staff, also allocated the assets over their service lives on a straight-line basis. Both used the same general principles as Mr. Watson did in his depreciation study. For many accounts, however, they reached different conclusions regarding average service lives and net salvage, which led to very different results. In addition, both ATOC and Staff disallowed at least portions of Oncor's investment in automated meters purchased before the consideration and adoption of the Commission's advanced metering rule, P.U.C SUBST. R. 25.130. Although Mr. Srinivasa accepted Oncor's accelerated depreciation of its remaining meters, Mr. Pous did not. Lane Kollen, on behalf of the Cities, also rejected the accelerated depreciation of the meters Oncor will be replacing.

Michael Majoros, also on behalf on the Cities, did not perform a depreciation study. In his testimony, he rejected the traditional approach for determining costs of removal followed by

⁴⁴⁷ Watson Direct, Oncor Ex. 15 at 5-6.

⁴⁴⁸ Watson Direct, Oncor Ex. 15 at 8, 25; Watson Supplemental, Oncor Ex. 16 at 7.

Messrs. Watson, Pous, and Srinivasa and suggested alternative methods. James Selecky for TIEC also did not present a depreciation study, but offered a recommendation regarding the calculation of inflation in determining net salvage. Those recommendations are discussed in Section VII.G.2 of this Proposal.

The ALJs generally accept the depreciation analysis conducted by Oncor witness Dane Watson, which they found to be the most thorough and reliable. Mr. Watson reviewed many experience bands instead of one overall band, gave greater weight to recent experience as appropriate, and properly exercised judgment to adjust the service lives and net salvage in either direction. In contrast, both Mr. Pous and Mr. Srinivasa generally reviewed only overall grand averages. Most of their proposed adjustments were successfully rebutted by Mr. Watson. In addition, Mr. Srinivasa's recommendations suffered from several errors in inputs and calculation.

The ALJs do agree, however, with ATOC's recommended service lives for two specific accounts and Staff recommended service life for one account. They also agree with ATOC's or Staff's net salvage values for several accounts. Those specific recommendations are discussed in those subsections. The ALJs reject the approaches to net salvage proposed by TIEC witness Selecky and Cities witness Majoros, as well as Mr. Pous' treatment of reimbursed retirements.

The ALJs accept Oncor's proposal for an 11-year depreciation period for its conventional existing meters, which will be replaced pursuant to Oncor's Advanced Metering System (AMS) deployment plan. As discussed in Section VII.L. of this Proposal, they find that 41.82 % of Oncor's investment in automated metering was imprudently incurred. They find that the remainder of that investment should also be depreciated over 11 years, as proposed by Oncor. For reasons discussed in Subsection VII.G.3., they decline to recommend that a regulatory asset be created for the conventional or automated meters scheduled for replacement.

For various accounts, ATOC and Staff compared Oncor's service lives and net salvage ratios to those approved for or recommended for other utilities. Oncor's position was that utilities are

different and that rates should be set on the basis of each utility's characteristics, although Oncor itself sometimes chose to rely on such comparisons. The ALJs agree with Oncor's position that such comparisons generally are not useful, because of the many variables in utility investment and service-area characteristics. The ALJs have considered those comparisons, however, for some accounts for which the Company-specific data appear to be unreliable.

1. Service Lives

Oncor's proposed service lives for Account Nos. 352, 357, 358, 360, 361, 366, and 380 through 399 were uncontested. Those proposed service lives should be used in calculating depreciation rates and expense.

Service lives for the following accounts were contested:

<u>Account Number and Description</u>	<u>Oncor</u>	<u>ATOC</u>	<u>Staff</u>
350-Transmission Deprec. Land Rights	70 R3	100 R3	70 R3 ⁴⁴⁹
353-Transm. Substation Equip.	46 L0.5	53 L0.5	60 L0.5
354-Transm. Towers and Fixtures	60 R3	70 R3	60 R3
355-Transm. Poles and Fixtures	50 R2	54 R2.5	60 R2
356-Transm.Overhead Conductor	50 R2	56 R2.5	60 R3
362-Distribution Substations	48 R1	54 L1	50 R1
364-Distrib Poles, Towers, and Fixtures	38 R1	41 R0.5	38 R1
365-Distrib. Overhead Conductor	37 R1.5	40 R1	40 R1
367-Distrib. Underground Conductor	34 R1.5	34 R1	40 L0.5
368-Distrib. Line Transformers	39 R1.5	39 R1.5	41 SO
369-Distrib. Services	32 S4	32 S4	38 L2
370-Distrib. Meters	(see section VII. G.3)		
371-Installation on Customer			
Premises (Guard Lights)	19 S6	19 S6	19 S5
373-Distrib. Street Lighting	24 S6	24 S6	28 S0

⁴⁴⁹ The parties' recommendations are expressed in terms of average service life and a recommended Iowa curve, which represents the dispersion of retirements around that average service life.

The ALJs find Oncor's proposed average service lives for all those accounts except 350, 362, and 364 to be most reasonable.⁴⁵⁰

a. Account 350-Transmission Land Rights

This account represents land rights and easements associated with transmission lines and transmission substations. Although Staff agreed with Oncor's proposed average service life for this account, ATOC did not, instead proposing an average service life of 100 years. Mr. Watson testified that the Company's proposed life was up to 50 % longer than the life of the assets that use the right. He stated also that there were not enough data to warrant a change from Oncor's current service life for this account. He noted that Oncor's proposed life was comparable to that of other large Texas utilities such as AEP and Entergy and longer than that of Southern California Edison.

Mr. Pous stated that survivor curves for several assets will extend for more than 100 years. He also pointed out that few of the easements have expiration dates and that in urban areas, transmission easements are likely to be used and reused.

Although other utilities have shorter average service lives for this account, the ALJs find Mr. Pous's testimony on this issue to have been the most convincing. Oncor's rebuttal did not successfully address Mr. Pous' observations. They recommend a 100-year service life for this account.

⁴⁵⁰ The account-specific issues pertaining to Oncor's, ATOC's, and Staff's service-life recommendations are discussed, in numerical account order, in Rebuttal Testimony of Dane A. Watson (Watson Rebuttal), Oncor Ex. 42 at 45-92; Supplemental Rebuttal Testimony of Dane A. Watson (Watson Supplemental Rebuttal), Oncor Ex. 180 at 11-26; Pous Direct, ATOC Ex. 2 at 14-32; and Revised Direct Testimony of Nara V. Srinivasa (Srinivasa Revised Direct), Staff Ex. 8 at 33-72.

b. Account 353-Transmission Substation Equipment

Oncor proposed a service life of 46 years, while ATOC and Staff proposed average service lives of 53 and 60 years, respectively. Mr. Watson persuasively pointed out that the actuarial analysis of this account exhibits a trend toward a shorter service life. Although transformers, the largest category of investment in this account, are expected to last longer than 50 years, that category does not make up a majority of the investment. Other categories, including switchgear, controls, circuit breakers, and other equipment, have shorter lives. The ALJs recommend Oncor's proposed average service life.

c. Account 354-Transmission Towers and Fixtures

Staff agreed with Oncor's proposed average service life of 60 years; ATOC recommended a 70-year life. Either is a significant increase from the existing 45-year average service life. Mr. Watson correctly pointed out that Mr. Pous looked at only the longest experience band, while other bands support Oncor's proposed life. The ALJs also agree with Oncor that ATOC's reliance on the proposed service life for SPS is misplaced. They recommend use of the 60-year average service life.

d. Account 355-Transmission Poles and Fixtures

Oncor recommended an average service life of 50 years, compared with average service lives of 54 years and 60 years recommended by ATOC and Staff, respectively.⁴⁵¹ Again, Mr. Watson persuasively testified that he looked at a number of different bands and that more recent experience is more indicative of ongoing operations. The ALJs recommend use of his proposed average service life.

⁴⁵¹ In discussing this account, counsel for ATOC made this astute, if understated, observation: "It is difficult for laymen to judge the 'fit' of various survivor curves." ATOC Initial Brief at 39.

e. Account 356-Transmission Overhead Conductor

For this account, Oncor proposed an average service life of 50 years, ATOC proposed an average service life of 56 years, and Staff proposed an average service life of 60 years. As with Account 355, Mr. Watson persuasively testified that he looked at a number of different bands and that more recent experience is more indicative of ongoing operations.

f. Account 362-Distribution Substations

Oncor recommended an average remaining service life of 48 years, compared with the recommendations of 54 years by ATOC and 50 years by Staff. In his rebuttal, Mr. Watson acknowledged that Mr. Pous showed more than one band as support for his recommendation and that both curves matched well for all the bands. He stated he chose the shorter service life because a trend toward a shorter life as shown in the progression from the 1990-2007 band to the 1998-2007 band to the 2002-2007 band. The ALJs find Mr. Watson's observation of that trend to be convincing. Mr. Watson acknowledged that Staff's 50-year average service life would also reflect that trend. The ALJs recommend use of Staff's 50-year average service life.

g. Account 364-Distribution Poles, Towers, and Fixtures

Oncor and Staff agreed on a 38-year average service life. ATOC proposed an average service life of 41 years. Although the difference in years seems insignificant, the investment in this account was approximately \$1.2 billion, so an apparently minor difference has a major revenue impact.

For this and the remaining distribution accounts, Oncor had insufficient retirement data to perform actuarial analyses. Instead Mr. Watson used the Simulated Plant Record (SPR) method. The method is used for determining the life parameters for mass property account that do not have aged data. Under the SPR method, the life parameter under consideration is applied to the mass

property account's historical additions to calculate the simulated plant balance over a selected period and the result is compared to the actual book balance.

For this account, the conformance index (CI), which measures the closeness of the fit between the actual experience and the simulated experience, was in the fair-to-poor range. Mr. Watson stated he recognized that the life of these assets was beginning to lengthen and moved the average service life from the current 27 years to 38 years. He testified Mr. Pous' use of 41 years was one of the most extreme possibilities and therefore unwise and unacceptable.

Mr. Pous testified that he had chosen the best fitting statistical result. He believed the data would justify an even longer average service life.

The Company had the burden of showing why its proposed average service life was the more reasonable. For this account, because there was very little difference between the match for Mr. Pous's selection and Mr. Watson's, the ALJs find the Company failed to carry that burden. They find Mr. Pous' recommendation should be used.

h. Account 365-Distribution Overhead Conductor

Oncor proposed an average service life of 37 years, compared with ATOC's and Staff's recommended life of 40 years. As with the previous account, neither the Company's nor ATOC's and Staff's selection matched the data well.

Mr. Watson acknowledged that the life of these assets may be increasing from the current approved life of 34 years. In rebutting Mr. Srinivasa, Mr. Watson provided specific reasons, based on conversations with engineering and operating personnel, why it was appropriate to moderate that increase.⁴⁵²

⁴⁵² Watson Supplemental Rebuttal, Oncor Ex. 180 at 13-14.

Mr. Watson's testimony on this issue was convincing. The ALJs find Oncor's proposed average service life should be used for this account.

i. Account 367-Distribution Underground Conductor

Oncor recommended an average service life of 34 years. ATOC agreed, while Staff recommended 40 years.

In his rebuttal testimony, Mr. Watson identified an error in Staff's analysis that Mr. Srinivasa subsequently corrected in this supplemental testimony. In his own rebuttal to that supplemental testimony, Mr. Watson, as with the previous account, identified several factors that showed both an increase in service life from the current life of 32 years and reasons to moderate that increase.⁴⁵³

Again, the ALJs find Mr. Watson's explanation to be convincing and recommend the use his proposed average service life for this account.

j. Account 368-Distribution Line Transformers

Oncor proposed an average service life of 39 years, as did ATOC. The Staff proposed an average service life of 41 years.

Oncor's cross-examination of Mr. Srinivasa demonstrated that although his conformance index may have been slightly higher for the 1950-2007 observation band, the R1.5 curve used by Mr. Watson had the highest conformance index for subsequent bands such as 1958-2007, 1963-2007, and 1968-2007. Mr. Watson also identified specific operations evidence that called for the use of the 39-year life over other longer lives.⁴⁵⁴ The ALJs find Oncor's proposed average service life should be used.

⁴⁵³ Watson Supplemental Rebuttal, Oncor Ex. 180 at 15-16.

⁴⁵⁴ Watson Supplemental Rebuttal, Oncor Ex. 180 at 18-19.

k. Account 369-Distribution Services

Oncor and ATOC proposed an average service life of 32 years, compared with 38 years recommended by Staff. Mr. Watson's supplemental rebuttal showed his selected curve to have a higher conformance index than Mr. Srinivasa's for most observation bands. Again, also, Mr. Watson provided reasons, based on discussions with engineering and operations personnel, justifying his proposed service life.⁴⁵⁵ The ALJs find Mr. Watson more credible on this issue and recommend use of his proposed average service life.

l. Account 371-Installation on Customer Premises (Guard Lights)

Oncor, ATOC, and Staff all recommended an average service life of 19 years. However, Staff proposed to use the S5 curve as opposed to the S6 curve recommended by Mr. Watson. During cross-examination, Mr. Srinivasa agreed he looked only at the longest experience band.⁴⁵⁶ Mr. Watson testified that his selected curve had a higher conformance index using shorter experience bands. He observed that shorter bands appeared more pertinent to this account, given its 19-year average service life. The ALJs agree and recommend use of Oncor's and ATOC's proposed average service life of 19 S6.

m. Account 373-Distribution Street Lighting

Oncor and ATOC recommended an average service life of 24 years; Staff recommended 28 years. While Staff's conformance index was higher for the longer experience bands such as 58, 40, and 35 years, Oncor's was shorter for smaller, more recent bands, including 30, 25, 20, 15, and 10 years. The ALJs find those more recent experience bands to be more relevant and recommend use of Oncor's and ATOC's proposed average service life for this account.

⁴⁵⁵ Watson Supplemental Rebuttal, Oncor Ex. 180 at 21-22.

⁴⁵⁶ Tr. Vol. 8 at 1357 (Jan. 26, 2009).

2. Net Salvage

Net salvage is the amount received for retired property (salvage) minus any costs incurred to remove or sell it (removal). Under straight-line depreciation as has been used by the Commission, positive net salvage reduces the amount to be depreciated over time, while negative net salvage increases it. Mr. Watson calculated net salvage percentages for transmission and distribution plant using Company data from 1995 or 1998 through 2007 and for general plant using Company data from 1995 through 2007. He used averages for various combinations of years, along with discussions with Company personnel, to determine his recommendations.

Mr. Watson testified that although the net salvage values for general plant have changed very little since they were set in 1994, the net salvage values for transmission and distribution plant have changed significantly. Those changes were due to actual removal costs being greater than reflected in the current depreciation rates. For some transmission assets, proposed longer lives would also increase the removal costs.⁴⁵⁷

Mr. Watson stated that, because net salvage rates have remained unchanged for so long, Oncor has incurred approximately \$70 million in unrecovered removal costs. Mr. Watson testified that depreciation rates must be set at a level to allow that deficiency to be recovered and spread over the remaining life of Oncor's property assets. In addition, according to Mr. Watson, Oncor has not accrued approximately \$76 million needed toward future removal costs.⁴⁵⁸

Cities, TIEC, and ATOC raised several overriding issues regarding Oncor's calculation and treatment of net salvage. The ALJs discuss those below, then discuss account-specific recommendations from Oncor, ATOC, and Staff.

⁴⁵⁷ Watson Direct, Oncor Ex. 15 at 20-21.

⁴⁵⁸ Watson Direct, Oncor Ex. 15 at 22.

Mr. Majoros, for the Cities, took issue with Mr. Watson's calculation and inclusion of future inflation in the net salvage rates. In his opinion, that traditional approach resulted in an overrecovery from current ratepayers and an underrecovery from future ratepayers, by front-loading the recovery of future inflation.⁴⁵⁹

Mr. Majoros offered two possible solutions to that perceived problem. First, he recommended that the Commission charge removal cost against replacement assets or current expense. On cross-examination, however, Mr. Majoros agreed that the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires utilities to recover the cost of removal through depreciation rates.⁴⁶⁰ P.U.C. SUBST. R. 25.72, which Mr. Majoros had not read,⁴⁶¹ requires electric utilities to keep their accounts in accordance with the FERC Uniform System. Mr. Majoros argued that cost of removal is an exception to that rule, because P.U.C. SUBST. R. 25.231(b)(1)(B) does not mention "cost of removal" or "net salvage." That rule, which sets out the components of allowable expense, includes:

(B) Depreciation expense based on original cost and computed on a straight line basis as approved by the commission. Other methods of depreciation may be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.

In Mr. Majoros' view, the absence of those phrases placed the Texas depreciation rule in "direct contrast" to the FERC rule. The ALJs disagree. First, Rule 25.231(b)(1)(B) does not exclude cost of removal or net salvage from depreciation expense, either explicitly or implicitly. Second, Rule 25.72 states electric utilities are to abide by the FERC system with regard to depreciation and other accounts. Third, the Commission many times has included cost of removal in depreciation

⁴⁵⁹ Direct Testimony of Michael J. Majoros, Jr. (Majoros Direct), Cities Ex. 2 at 15.

⁴⁶⁰ Tr. Vol. 7 at 1165-66 (Jan. 23, 2009).

⁴⁶¹ Tr. Vol. 7 at 1167-68 (Jan. 23, 2009).

calculations.⁴⁶² The ALJs conclude Rule 25.231(b)(1)(B) allows, and Commission precedent mandates, inclusion of cost of removal in depreciation expense.

In the alternative, Mr. Majoros recommended the Commission limit recovery of removal costs to the net present value of the future removal cost, which would be recalculated with each rate case filing. Mr. Majoros' approach would depart from straight-line depreciation as required by the Commission's rule and consistently applied by the Commission, without being more equitable. Under the traditional approach, the recovery of removal costs follows the same ratable straight-line pattern as the recovery of installation costs and material costs. Mr. Majoros' approach would defer much of the removal cost to future customers, while abandoning Commission precedent and injecting additional uncertainty into the regulatory process. The ALJs find Mr. Majoros' alternatives should be rejected.

Mr. Selecky, for TIEC, attempted to deal with future inflation in a different way. In his opinion, Mr. Watson was remiss in relying on historical inflation rates to predict future inflation. Mr. Selecky observed that Oncor's transmission and distribution assets would have an average service life of 42 years if the Commission approves Oncor's recommendations. He testified that over the last 42 years, the Consumer Price Index (CPI) has increased at an average annual rate of approximately 4.16 % a year. Recent authoritative projections, however, indicate the CPI is expected to increase at a rate of approximately 2.1-2.4 % for the next few years. To account for that difference and reduce the amount of inflation included in Oncor's net salvage ratios, Mr. Selecky proposed decreasing those ratios by 33 %.⁴⁶³

Mr. Watson testified that Mr. Selecky's analysis was flawed in several respects. First, the average age of the Company's retirements is only 18.12 years, meaning those were put in service well after the high inflation years of the late 1970s and early 1980s. In the last twenty years, the average inflation has been a little over 3 %. He also noted that the average age of Oncor's

⁴⁶² See Oncor Reply Brief at 94, fn. 31.

⁴⁶³ Direct Testimony of James T. Selecky (Selecky Direct), TIEC Ex. 2 at 10-20.

transmission and distribution assets is 13.89 years, meaning that the assets used to calculate net salvage have already experienced 14 of the 18 potential years of inflation. He further testified that Mr. Selecky's 33 % reduction was arbitrary and inappropriate.⁴⁶⁴ On cross-examination, moreover, Mr. Selecky agreed that the CPI, on which he relied, is a measure of inflation in consumer goods. It is not specifically a measure of inflation in labor expense, which is a major component of removal costs.⁴⁶⁵

Obviously, inflation rates are hard to predict and subject to change, especially in volatile economic times. Nevertheless, the ALJs find Mr. Watson's reliance on historical inflation to be more reliable than Mr. Selecky's estimate and adjustment. They find Oncor's approach should be used.

Mr. Pous, for ATOC, recommended that third party reimbursements⁴⁶⁶ should be included as an offset to negative net salvage. Mr. Watson's testimony established, however, that such reimbursements are prepayments for new property being installed. As such, they are properly used to reduce Oncor's rate base.

Oncor, ATOC, and Staff agreed on the net salvage values for the following accounts: 350, 360, and 371. Those should be adopted. Their contested net salvage recommendations for the other accounts are summarized and discussed below:

<u>Account Number and Description</u>	<u>Oncor%</u>	<u>ATOC%</u>	<u>Staff%</u>
352/361-Transm./Distrib. Struct. & Equip.	-50	-10	-33
353-Transm. Station Equip.	-15	- 5	-13
354-Transm. Towers and Fixtures	-35	-20	-34
355-Transm. Poles and Fixtures	-100	-60	-65
356-Transm.Overhead Conductor	-65	-25	-49
357-Transm. Underground Conduit	-10	-10	0

⁴⁶⁴ Watson Rebuttal, Oncor Ex. 42 at 18-20.

⁴⁶⁵ Tr. Vol. 5 at 800-802 (Jan. 21, 2009).

⁴⁶⁶ The example provided by Mr. Watson was a reimbursement by TxDOT to Oncor if TxDOT needs facilities to be moved to widen a road.

358-Transm. Undergr. Conduit & Devices	-10	-10	0
362-Distribution Substations	-15	-10	-11
364-Distrib. Poles, Towers, and Fixtures	-65	-40	-65
365-Distrib. Overhead Conductor	-55	-40	-53
366-Distrib. Underground Conduit	-55	-20	-50
367-Distrib. Underground Conductor	-10	-5	-5
368-Distrib. Line Transformers	-20	-15	-14
369-Distrib. Services	-20	-10	-19
370-Distrib. Meters	*****		
373-Distrib. Street Lighting	-25	-15	-25

The ALJs recommend ATOC's proposed net salvage value for Account 365. They recommend Staff's proposed values for Accounts 352/361, 354, and 366, and ATOC's and Staff's common recommendation for Account 367. For the remainder, they recommend Oncor's proposed values.⁴⁶⁷

a. Account 352/361-Trans./Distrib. Structures & Equip.

Oncor proposed a net salvage value of negative 50 %. ATOC proposed negative 10 %, while Staff proposed negative 33 %.

Mr. Watson testified his full 13-year database yielded a negative 67 % net salvage and that the indications from the 3-, 5-, and 10-year bands were more negative. As Mr. Pous and Mr. Srinivasa pointed out, the data from this account were quite variable. The actual retirements on which the estimate was based were a very small fraction of the total plant. Given those issues, the ALJs considered the net salvage values recommended for other utilities. Mr. Pous testified Mr. Watson had supported values of negative 20 % for transmission and negative 15 % for distribution. Mr. Pous described Mr. Watson's recommendation as the most negative he was aware of for any utility. Mr. Watson, in rebuttal, cited values of negative 35 % and negative 40 % for Consolidated Edison and California Edison, utilities which he believed to be more closely

⁴⁶⁷ The account-specific issues pertaining to Oncor's, ATOC's, and Staff's net-salvage recommendations are discussed, in numerical account order, in Watson Rebuttal, Oncor Ex. 42 at 45-92; Pous Direct, ATOC Ex. 2 at 47-74; and Srinivasa Revised Direct, Staff Ex. 8 at 33-72.

comparable to Oncor. Based on all that information, the ALJs find the Staff's recommended net salvage value of negative 33 % to be the most reasonable.

b. Account 353-Transmission Station Equipment

Oncor proposed net salvage of negative 15 %. ATOC proposed negative 5 % and Staff negative 13 %.

Mr. Pous, for ATOC, testified that Oncor had overstated net salvage because transformers represent 25 % of the investment in the account but only 14 % of the retirements. He expected transformers to have a less negative, or even a positive salvage value because of the copper they contain. He stated that circuit breakers, which have limited or no salvage value, represent a higher percentage of retirements but a lower percentage of investment. Mr. Pous also believed contract labor was overrepresented in the database. He compared Mr. Watson's recommendation in this case to his recommendation of negative 10 % for SPS.

Mr. Srinisava, for Staff, looked at the years 1995-2007, which showed overall values of 2 % gross salvage and 15 % cost of removal.

In rebuttal, Mr. Watson testified that although transformers do contain copper, they are also heavy and filled with oil, which makes them difficult to transport and requires special handling, testing, and disposal. He agreed that the database contained contract labor, which he expected the Company to continue to use. He pointed to other companies with higher net salvage values for this account. He testified that more recent experience for 2002-2007 showed a net salvage average of 15.2 %, which he found more likely to reflect ongoing activities than the 1995-2007 average.

The ALJs find Mr. Watson's arguments most convincing on this issue and recommend use of his negative 15 % net salvage value.

c. Account 354-Transmission Towers and Fixtures

Oncor proposed a net salvage value of negative 35 % of this account. Staff's recommendation was negative 34 %. ATOC's was negative 20 %.

Mr. Pous stated the Company's data showed "less than robust levels of retirements" and noted that he proposed a zero level for this account for SPS. Mr. Watson responded that Oncor has retired on average nearly \$1 million per year in assets from this account for a number of years, while SPS has had no retirements on its one transmission line. According to Mr. Watson, the 2007 13-year average showed negative 51 % net salvage and the five-year average showed negative 40 % net salvage. The three-year average showed negative 33 %. Although Mr. Watson disagreed with Staff's minor reduction, he found it to be acceptable. The ALJs find the Staff's recommendation to be the most reasonable.

d. Account 355-Transmission Poles and Fixtures

Oncor's proposed net salvage for this account was negative 100 %, while ATOC and Staff were close to each other, recommending negative 60 and negative 65 %, respectively.

Mr. Pous, for ATOC, testified that Oncor's proposed value was the most negative net salvage value in the industry. He believed Oncor had not provided a reasonable explanation for that difference and recommended the value Mr. Watson had proposed for SPS. Mr. Srinivasa believed the Company's proposed value was excessive and based on sporadic data. His proposal was in accordance with his recommendation for Account 364-Distribution Poles and Structures.

Mr. Watson testified that the Company's rebuild activity has increased significantly and that his recommendation was based on the Company's historical data. The five-year net salvage value was negative 229 %; the three-year value was 163 %. He stated his recommendation was a moderation of those historical levels.

Although the net salvage value is highly negative, Mr. Watson's testimony was convincing and based on Company data. The ALJs recommend its use.

e. Account 356-Transmission Overhead Conductor

There was wide variance among the parties' recommendations for this account. Oncor proposed net salvage value of negative 65 %; ATOC proposed negative 25 %; and Staff proposed negative 49 %.

Mr. Pous cited the variability of Oncor's net salvage percentages over the years and described Oncor's proposal as the most negative net salvage value for this account in the industry. He pointed out that Mr. Watson's recommended value for SPS was negative 10 % and that Mr. Pous' proposed value would provide Oncor with over three times the average level of net salvage it has experienced in the reported database.

Mr. Srinivasa believed the increased cost of scrap metals should continue in the future, increasing the gross salvage value of these assets. He testified that economies of scale should reduce the cost of removal, which he set at 70 %.

Mr. Watson's study showed a 13-year average of negative 136 %, a 5-year average of negative 154 %, and a three-year average of 90 %. He testified he had moderated those figures to 65 % to reflect decreasing rebuilding activities. He stated that at least one other utility that he considered comparable, Southern California Edison, had an approved net salvage of negative 85 % for this account.

Mr. Watson took issue with Staff's forecast of continuing high scrap metal prices. He stated those prices were at an historic high during the period relied upon by Staff. Providing data from the London Metals Exchange and the American Metals Market, he illustrated that scrap metal prices are now decreasing to less than half their 2005-2007 levels. He further observed that Oncor's historical

data for this and other accounts already reflect economies of scale, considering Oncor is one of the largest utilities in the United States.

The ALJs find Mr. Watson's analysis to be the most convincing and recommend the use of this proposed net salvage value.

f. Account 357-Transmission Underground Conduit

Oncor and ATOC recommended a net salvage value of negative 10 %, while Staff proposed zero net salvage.

Although most conduit is abandoned in place, some items are not. Mr. Watson's study established that the Company has had two years of retirements in recent years, reflecting net salvage of negative 29 %. The ALJs recommend the use of Oncor's proposed net salvage value.

g. Account 358-Transmission Underground Conduit and Devices

Again, both Oncor and ATOC recommended a net salvage value of negative 10 %, while Staff proposed zero net salvage.

Oncor successfully established that Staff's use of the median to calculate its recommendation was inappropriate. Staff's recommendation was also predicated on the prices for scrap metal continuing to be very high, a premise that Mr. Watson successfully rebutted. The ALJs recommend use of Oncor's proposed net salvage value.

h. Account 362-Distribution Substations

For this account, Oncor proposed a net salvage value of negative 15 %. ATOC proposed negative 10 % and Staff negative 11 %.

The arguments regarding this account are similar to those for Account 353-Transmission Station Equipment. Mr. Watson's study showed a 13-year net salvage value of negative 18 %, a 5-year value of negative 16 %, and a 3-year value of negative 16 %. The ALJs find his proposed net salvage value to be reasonable and recommend its use.

i. Account 364-Distribution Poles, Towers, and Fixtures

For this account, Oncor and Staff agreed on a net salvage value of negative 65 %. ATOC recommended a value of negative 40 %.

The ALJs accepted ATOC's proposed service life for this account. With regard to net salvage, Mr. Pous contended Oncor's proposal was exaggerated for several reasons. He observed that Oncor's proposal was 2.6 times higher than Mr. Watson's proposal for SPS. He contended that the 2002-2007 period, which generally shows more negative net salvage, was not a representative period, because it included two or three of the worst storms in the Company's history. He pointed out that the Company began leaving retired poles in place starting in 2004, which would reduce overall removal costs. He finally objected to the overall size of the revenue requirement for such highly negative salvage values.

Mr. Watson's data show an increase in negative net salvage over the 2002-2007 period, with a slight drop in 2007 from the negative 90s to negative 69 %. He cited the three- and five-year averages which are both above negative 90 %, and the ten-year average, which is negative 72 %. Mr. Watson rejected the comparison to SPS, which has approximately \$164 million in this account compared with Oncor's approximate \$1.23 billion. He also cited Pacific Gas and Electric, Consolidated Edison, and Southern California Edison, which have approved net salvage values for this account of negative 80, negative 100, and negative 250 %, respectively. Mr. Watson also testified that the storms during the most recent five-year period did not run up the net salvage for this account, because the costs mostly were booked to operations and maintenance expense or the self-insurance reserve.

The ALJs find Mr. Watson's study and testimony support Oncor's proposed net salvage value for this account.

j. Account 365-Distribution Overhead Conductor

Oncor proposed a net salvage value of negative 55 %. ATOC proposed negative 40 %. Staff proposed negative 53 %. Although Mr. Watson considered his own recommendation to be preferable, he found Staff's recommendation acceptable.

Mr. Pous raised issues regarding SPS, the size of the increase, and third-party contributions that have been addressed with regard to other accounts. The ALJs agree with Oncor on those particular arguments for this account. Mr. Pous also observed that, while only 7 % of the investment in this account is related to reclosers, almost 30 % of the retirement activity corresponded to reclosers. The majority of the investment in the account is related to conductors. In his opinion, the unit cost to remove conductors should be less than the unit cost to remove reclosers, which would lower the overall cost of removal for this account.⁴⁶⁸ He further argued that advanced metering should improve the Company's responses to storms, which would further reduce removal costs.

The ALJs find the second of those arguments to be too attenuated to serve as a reason for reducing net salvage. Although the Company expects its advanced metering to improve its storm response capabilities, the effect of those capabilities on future removal is too difficult to quantify. With regard to the recloser argument, however, Mr. Watson merely argued that Mr. Pous had provided no evidence for his contention. The ALJs agree with ATOC that Mr. Pous' engineering experience provided at least some basis for that observation, which Oncor should have addressed. Although the evidence is fairly sketchy, the ALJs find the preponderance of that evidence supports ATOC's proposed net salvage value for this account.

⁴⁶⁸ Pous Direct, ATOC Ex. 2 at 65-66; ATOC Exs. 13 and 14.

k. Account 366-Distribution Underground Conduit

Oncor recommended a net salvage value of negative 55 %. ATOC recommended negative 20 % and Staff negative 50 %.

Mr. Watson's study showed a negative 50 % net salvage over the last 10 years, a negative 66 % net salvage over the last 5 years, and a negative 81 % net salvage over the last 3 years. Staff's recommendation was based on the 10-year average, which Mr. Watson considered unreasonable, due to the increasingly negative salvage value over the years. He pointed out that his recommendation was well below the history for recent years.

In addition to his arguments that have already been addressed regarding other accounts, Mr. Pous observed that conduit, which represents 46 % of the investment in this account, is generally left in place and not removed. Conduit represented only 14 % of the retirement activity in the account, however, suggesting that future overall removal costs will be less. He further pointed out that the Company replaced a significant portion of underground conduit in the Las Colinas area in 2001 and 2002. That period showed a net salvage value of negative 28 %, which suggested to Mr. Pous that future economies of scale would further reduce removal costs.⁴⁶⁹

The ALJs disagree with Mr. Pous' economies of scale justification for his recommendation. There is no guarantee future removals of conduit on Oncor's system will be of such scale; moreover, the net salvage value for that period is still more negative than ATOC's recommendation. Mr. Pous did make a point about the percentage of conduit in the account versus the amount retired, however. For that reason, the ALJs find it reasonable to moderate Oncor's proposal further and to recommend use of Staff's proposed net salvage value.

⁴⁶⁹ Pous Direct, ATOC Ex. 2 at 68-69; ATOC Exs. 13 and 14.

l. Account 367-Distribution Underground Conductor

The recommendations for this account were not far apart: negative 10 % for Oncor and negative 5 % for ATOC and Staff.

Mr. Watson criticized ATOC and Staff for relying on the past one or two years of data, as opposed to the last 3, 5, or 10 years, which were in line with the Company's proposal. He noted that the last two years represented the highest levels of net salvage in history. He particularly criticized Mr. Srinivasa for using one year of gross salvage and a three-year average removal cost.

As with the previous account, Mr. Pous pointed out that switchgears, which represented 13 % of the account investment, represented 27 % of the retirement activity. He testified that underground conductor was much more likely to be left in place, which would yield lower removal costs for the account and a less negative net salvage value. Although Mr. Watson mentioned that argument, he did not effectively rebut it. The ALJs recommend the use of ATOC's and Staff's proposed net salvage value for this account.

m. Account 368-Distribution Line Transformers

Oncor proposed a net salvage value of negative 20 %. ATOC proposed negative 15 % and Staff negative 14 %.

Many of the arguments concerning this account-comparisons with other utilities, the effects of advanced metering, trends in scrap metal costs-have been addressed with regard to other accounts. For this account in particular, Mr. Pous argued that the historical cost of removal may include some impact of Polychlorinated Biphenyls (PCBs), which would result in much higher cost of removal than in the future. Currently, Oncor estimates that only 8 % of its transformers contain PCBs.

Mr. Watson testified that PCBs were removed from the system before the historical period that he analyzed. He further testified that Oncor continues to test transformer oil for possible PCB contamination, so that activity is not purely historical. The data show net salvage averages of negative 21 % over the last three years, negative 26 % over the last five years, and negative 23 % over the last ten years. The ALJs find Oncor's proposed net salvage value of negative 20 % to be reasonable.

n. Account 369-Distribution Services

Oncor proposed a net salvage value of negative 20 %, compared with ATOC's negative 10 % recommendation and Staff's negative 19 %.

Staff's recommendation was based primarily on the continuation of high scrap metal prices, which Oncor successfully addressed. Mr. Pous testified that the removal of more overhead than underground services during the past five years had artificially inflated the negative net salvage value. Mr. Watson testified, however, that Company data showed a higher negative net salvage for the underground services in this account. Therefore, if anything, the historical negative net salvage was understated.

The ALJs find Mr. Watson's testimony persuasive and recommend use of his proposed net salvage value.

o. Account 373-Distribution Street Lighting

Oncor and Staff agreed on a net salvage value of negative 25 %. ATOC recommended negative 15 %.

Mr. Pous argued that luminaries, with higher per-unit removal cost, are overrepresented in the historical data, while conductor and poles are underrepresented. Mr. Watson countered that the

removal cost for poles is likely to be higher, so the data are not skewed toward unrepresentative higher removal costs. Mr. Pous also criticized Mr. Watson for removing street lighting sales from his data. Mr. Watson observed, however, that only \$5,025 of street lighting assets were sold between 1998 and 2007.

The data show a 5-year average net salvage value of negative 27 % and a 10-year average of negative 32 %. The ALJs concur with Mr. Watson and recommend Oncor's proposed net salvage value be used for this account.

3. Account 370- Distribution Meters

The dispute over the prudence of Oncor's investment in automated meters is addressed in Section VII.L. of this Proposal. As stated there, the ALJs find 41.82 % of Oncor's investment in automated meters should be disallowed as imprudent. That decision, however, does not answer the question of how quickly Oncor's investment in the remaining automated meters, and in its conventional meters, should be depreciated.

Under its AMS plan approved in Docket No. 35718, Oncor is scheduled to replace its existing conventional and automated meters with advanced digital meters by the end of 2012. In recognition of that fact, Oncor considered depreciating all its remaining meters over a five-year period. Oncor decided that accelerated depreciation was too accelerated, however. It proposed instead to depreciate its meters over an 11-year period to match the AMS surcharge period. For power line equipment installed before January 1, 2008, it proposed a recovery period of seven years.⁴⁷⁰

ATOC and Cities objected to Oncor's proposal.⁴⁷¹ Mr. Pous, for ATOC, testified that conventional meters should be depreciated over a 35-year period and automated meters, to the extent

⁴⁷⁰ Pruett Direct, Oncor Ex. 29 at 38.

⁴⁷¹ Staff accepted the 11-year period for the meter investment it considered to be prudent.

they were found to be prudent, over a 20-year period⁴⁷² Cities' witness Lane Kollen proposed that the net book value of the existing meters be reclassified to a regulatory asset, that the asset be amortized over a 31-year life, and that the meter-related regulatory asset be recovered on a levelized basis to prevent overrecovery of that investment. Mr. Kollen's 31-year life was based on his estimated service life for conventional meters, as he recommended disallowance of Oncor's automated meters.⁴⁷³

Keith Pruett, for Oncor, agreed with Mr. Kollen's proposal to reclassify the meter investment as a regulatory asset. He explained that reclassification was appropriate because the meters will be retired within five years and Generally Accepted Accounting Principles (GAAP) will not allow continued depreciation of assets once they are retired. He rejected Mr. Kollen's proposed 31-year service life, however. As he put it, that proposal would require customers in 2040 still to be paying for meters removed from 2008 through 2012. He also objected to Mr. Kollen's proposed levelized recovery of that asset, which he viewed as contrary to test-year ratemaking principles.⁴⁷⁴

Mr. Pruett objected to Mr. Pous' proposed service lives for meters for the same reason he objected to Mr. Kollen's. Mr. Pous' proposed recovery period for conventional meters would be even longer.

The ALJs find Oncor's proposed 11-year depreciation period to be reasonable. If they were not to be replaced by advanced meters, Oncor's conventional and automated meters would have longer service lives. As is discussed in Section VII.L. of this Proposal, however, both the Legislature and the Commission have strongly encouraged utilities to move to advanced metering. Even though Oncor's conventional meters technically would be able to provide service for many years, it is clear that they are technologically obsolete. The same is true even of the automated meters, which do not have the advanced features set out in the Commission's AMS surcharge rule. Oncor is correct that

⁴⁷² Pous Direct, ATOC Ex. 2 at 32.

⁴⁷³ Kollen Direct, Cities Ex. 1 at 17-18; Tr.. Vol. 7 at 1109-10.

⁴⁷⁴ Pruett Rebuttal, Oncor Ex. 51 at 24-28.

those meters could be depreciated within the five years in which they are scheduled to be replaced. The proposed 11-year period is a reasonable compromise between their actual service lives and the service lives that might have been expected in the absence of Legislative and Commission action and technological advances.

The ALJs do not recommend reclassification of the meters as a regulatory asset in this case. First, the meters are still in service. Second, as discussed in Section VII.L., Oncor has stated it may wish to revisit its AMS Deployment Plan. If Oncor were to do so, and if the Commission were to agree to its proposal, the automated meters might not be removed from service by 2012. The ALJs find that reclassification of the meters as a regulatory asset is premature.

H. Amortization of 2004 and 2006 Restructuring Regulatory Assets.

In section V.G.1 the ALJs recommended that the Commission disallow Oncor's request to defer its 2004 and 2006 restructuring cost as a regulatory asset. Therefore Oncor's request to amortize this amount should likewise be denied.

I. Recovery of Intangible Property

Mr. Pruett explained that Oncor's intangible assets consist of its computer business systems and software, including its computerized billing systems, engineering and mapping systems, and capitalized upgrades to its existing computer applications. Oncor's investments in intangible assets are classified under the FERC Uniform System of Accounts as "electric utility plant in service," are depreciated over the systems useful life, and are included in Oncor's rate base.⁴⁷⁵

ATOC is the only party to challenge any portion of Oncor's request for intangible assets, specifically how Oncor amortized its intangible assets. ATOC's expert, Mr. Pous proposed two

⁴⁷⁵ Pruett Rebuttal, Oncor Ex. 51 at 21.

solutions to what he believed could be an over-recovery of Oncor's costs for the intangible assets. Oncor rejected one proposal, but agreed to the alternative proposal.

Mr. Pous' alternative proposal involves an additional cost accounting and rate-making mechanism for the recovery of costs for the intangible assets. Mr. Pous proposed that Oncor continue recording amortization expense for the various intangible assets as set out in its RFP until the next base rates go into effect following the next rate hearing. Any over-recovered costs for the intangible assets would be applied to Oncor's unamortized plant.⁴⁷⁶

Mr. Pruett understood that Mr. Pous' proposal "mirrors" the accounting and ratemaking treatment of tangible assets such as poles and conductors, and agreed to adopt Oncor's traditional plant accounting methods for its intangible assets.⁴⁷⁷ According to Mr. Pruett, Oncor agrees to do the following:

1. Beginning with this case, Oncor will develop an initial average or group amortizations rate to apply to its existing original cost investment in intangible assets that will remained fixed until new rates are approved by the Commission following Oncor's new rate case.
2. To determine the initial group amortization, Oncor's intangible asset amortization expense for the test year, \$14,634,315, is divided by the original cost investment in the intangible assets as of December 31, 2007, which is \$122,119,988. The result is 11.99 %.
3. Oncor will apply this rate to the total original cost investment in its intangible assets to determine and record the annual allowable amortized expense.⁴⁷⁸

Oncor described how it would implement Mr. Pous' alternative proposal, as detailed above, in Mr. Pruett's rebuttal testimony and in its Initial Brief. No one objected to implementing Mr. Pous' alternative proposal as detailed by Mr. Pruett. Therefore, the ALJs recommend that the

⁴⁷⁶ Pous Direct, ATOC Ex. 2 at 105.

⁴⁷⁷ Pruett Rebuttal, Oncor Ex. 51 at 212-22; Oncor Initial Brief at 154.

⁴⁷⁸ Pruett Rebuttal, Oncor Ex. 51 at 23.

Commission adopt Oncor's calculation of its intangible assets and the amortization process for these intangible assets described above.

J. Federal Income Tax Expense

1. Consolidated Tax Savings Adjustment

Staff and Intervenors asked that the consolidated tax savings adjustment (CSTA) be included in reducing Oncor's FIT calculations. Oncor emphatically holds that it should not have to pay any CTSA for several reasons. Oncor maintains that because it is a ring-fenced utility and now a partnership it is not eligible, nor is it appropriate to require that it include CTSA in its FIT expense. However, if the Commission is inclined to impose a CTSA, Oncor contends its fair amount should be zero.

The ALJs discussed a great deal of the background regarding Oncor's tax sharing agreement in Section V.B. regarding Oncor's ADFIT. The ALJs will not repeat the detailed discussion, but will provide a brief summary. Oncor entered into a tax sharing agreement with its parent company EFH and affiliates that requires Oncor to function as a stand-alone company. While EFH still includes Oncor in its consolidated tax return, Oncor is obligated to prepare its taxes as though it is a stand-alone corporation. The tax sharing agreement was created in October 2007 in an effort to insulate Oncor from the liabilities related to EFH and its affiliates.

a. Appropriateness of Making a CTSA

The ALJs previously addressed the issue of whether a utility in a rate case can impose the terms of any agreement between itself and its parent company or affiliates on the Commission, and held that a utility cannot.⁴⁷⁹ However, the Commission has discretion as to whether to impose a

⁴⁷⁹ For a detailed discussion, please refer to Section V.B.

CTSA and how to compute it.⁴⁸⁰ As a ring-fenced utility, and as a partnership for income tax purposes, Oncor encourages the Commission to use its discretion to refrain from imposing any CTSA. In addition, Oncor argues that the “sheer magnitude” of the CTSA justifies its denial.

According to Oncor, the question of whether a CTSA should be applied to a ring-fenced utility is a matter of first impression. Because of the tax sharing agreement, Oncor’s ratepayers are insulated from any risks from Oncor’s unregulated affiliates. In Docket No. 34077 (merger order), Oncor asserts that the Commission already found that ring-fencing commitments are in the public interest and are beneficial to ratepayers. If the Commission imposes a CTSA, Oncor argues that the Commission will have “pierced the separateness” that it previously found beneficial to the ratepayers.⁴⁸¹

Oncor also claims that the “sheer magnitude of CTSA” makes it inappropriate. Oncor’s FIT expense is about \$151 million. The proposed CTSA ranges from \$99 million to \$115 million, which is almost three-quarters of Oncor’s FIT expenses.⁴⁸² Oncor notes that although the impact of the CTSA was one of five factors the Commission considered when it first adopted its current approach in *Central Power & Light*, Docket No. 14965, none of the other parties addressed it. Oncor asks whether it is reasonable for Oncor’s ratepayers “to receive such a huge rate benefit resulting from tax losses incurred by unregulated affiliates . . .,” and answers that it is not.⁴⁸³

Oncor further denies that it is appropriate to impose the CTSA for several other reasons. The Commissioners who created the CTSA over 10 years ago in Docket No. 14965 no longer serve as Commissioners. Despite the length of time since the decision to impose a CTSA in that case, the Commission has not adopted a rule concerning this issue, even though it remains a required inclusion in Rate Filing Packages. Even if it were a rule, Oncor maintains that the Commission continuously

⁴⁸⁰ See *Public Utility Commission of Texas v. GTE-Southwest, Inc.*, 901 S.W.2d 401-411 (Tex. 1995) and *Public Utility Commission of Texas v. Texas Utilities Electric Company*, 935 S.W.2d 109 (Tex. 1996).

⁴⁸¹ Oncor Initial Brief at 156.

⁴⁸² Tr. Vol. 8 at 1463-64.

⁴⁸³ Oncor Initial Brief 156.

re-examines and modifies its rules to “improve its regulation of the electric industry,” and should do so in this case.⁴⁸⁴ Finally, Oncor maintains that the Commission has failed to consistently apply the CTSA, noting that in the past the CTSA was not an adjustment to the FIT expense, but was instead an adjustment to the rate base.

In the future, Oncor maintains that EFH will not include Oncor in its consolidated return because Oncor became a partnership in 2008. Under PURA, Oncor insists that it is no longer eligible to participate as a member of an affiliated group in filing a consolidated income tax return. PURA 36.060(a)(1) specifies that a utility’s income taxes shall be computed as though a consolidated return had been filed if “the utility is a member of an affiliated group eligible to file a consolidated income tax return . . .” Oncor witness Ms. Burns confirmed that Oncor is now a partnership and is not a member of an affiliated group. Consistent with the Commission ruling in two other rate cases, Oncor argues the Commission should deny the request to impose a CTSA against Oncor’s FIT expenses because Oncor is now ineligible to file a consolidated tax return.

In Application of Sharyland Utilities, LP for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344, Docket No. 22348, (Oct. 4, 2001), the Commission found in Finding of Fact No. 27 that:

27. Sharyland is a limited partnership, and therefore, a consolidated tax return would not be appropriate. Accordingly, Sharyland’s income tax expense need not reflect consolidated tax savings.⁴⁸⁵

Similarly, Oncor points out that in *Application of Electric Transmission Texas, LLC for a Certificate of Convenience and Necessity, for Regulatory Approvals, and Initial Rates*, Docket No. 33734, (Oct. 31, 2007), the Commission found that Electric Transmission Texas was “not part of a consolidated tax group” even though it was jointly owned by two utility holding

⁴⁸⁴ Oncor Initial Brief at 158.

⁴⁸⁵ Docket No. 22348, Order at 90 (Oct. 4, 2001).

companies. The Commission found that because the utility could not file a consolidated tax return, it was not subject to a CTSA.⁴⁸⁶

In response, Staff, OPC, TIEC, Cities and ATOC argue that the plain reading of PURA § 36.060 includes Oncor as a member of an affiliated group that is eligible for filing a consolidated tax return. The statute does not require that the affiliated group file a consolidated tax return, only that it be eligible to do so. Nor does the statute indicate that the utility, a member of the affiliated group, be eligible to file a consolidated tax return itself. In the test year, Oncor was clearly a member of an affiliated group. In 2008, because Oncor incorporated in Delaware as a LLC, and chose by default to be treated as a partnership for tax purposes, the issues became whether it was reasonable for Oncor to choose to be treated as a partnership, and if so whether it is still a member of an affiliated group.

Staff argues that Oncor has not proven that it was reasonable to elect to be treated as a partnership for tax purposes. Although, Ms. Burns asserted that if Oncor had elected to be treated as a corporation, it would have been subject to double taxation, thereby affecting its ability to attract investors, Ms. Burns provided no evidence for her opinion. Likewise, while Oncor postulates that Oncor is no longer jointly and severally liable for taxes owed the federal government because it is a partnership, Oncor offered no evidence in support of this position. Equally compelling, as Staff points out, Oncor presented no evidence weighing the alleged benefits of being a partnership with its costs.

However, Staff notes that if the Commission finds that Oncor was acting reasonably by choosing to file its taxes as a partnership, then the Commission should calculate Oncor's FIT under the "actual taxes paid" approach by including 80.04 % of Staff's recommended CTSA. According to Ms. Romines, FERC issued a Policy Statement on Income Tax Allowance on May 4, 2005, that is significant for three reasons. First, FERC determined that even if a utility such as Oncor is not a taxable entity, *i.e.* a partnership, a tax allowance on the utility's taxable income can be considered for

⁴⁸⁶ *Application Of Electric Transmission Texas, LLC For A Certificate Of Convenience And Necessity, For Regulatory Approvals, And Initial Rates*, Docket No. 33734, Order at 18, FoF No. 64.

ratemaking purposes. Second, if the partners have a tax liability because of the utility's income, the tax allowance is imputed to them. Third, the utility, in this case Oncor, must establish that the partners have either actual or potential income tax obligation for the utility's income.⁴⁸⁷

Oncor is owned by three different entities. EFH owns 80.04 % of Oncor. Oncor Management Investment LLC owns 0.21 %. Texas Transmission Investment LLC owns 19.75 % of Oncor.⁴⁸⁸ While Oncor has separated itself from the EFH group in many ways, it is still a member of an affiliated group eligible to file a consolidated return, if it chooses. Oncor is a limited liability corporation incorporated under Delaware law. If it does not elect to do otherwise, Oncor is required to compute its taxes as a partnership. However, Oncor is eligible to file its income taxes as a LLC, and EFH is eligible to file consolidated tax return. The fact that Oncor chooses not to for financial reasons, does not change that Oncor is a LLC or that it can be a member of an affiliation that is eligible to file a consolidated return. Therefore, the ALJs find that Oncor is not ineligible to recover its fair share of savings under the terms of PURA § 36.060.

The next question to address is whether a CTSA should be applied to a ring-fenced utility. Oncor reasons that because the Commission found that the merger agreement was in the best interest of the public, it indirectly approved the tax sharing agreement and the resulting tax consequences. Oncor further reasons that because ring-fencing insulates Oncor from the liabilities of its unregulated affiliates, the Commission should not breach the ring-fence around Oncor because to do so exposes Oncor to the liabilities of its other affiliates. Staff disagrees with Oncor's analysis. According to Staff, the important consideration is the benefit the affiliates received due to the "tax shield" Oncor provided, not whether Oncor subsequently entered into a tax sharing agreement with its affiliates.⁴⁸⁹

⁴⁸⁷ Romines Direct, Staff Ex. 3 at 21-22.

⁴⁸⁸ Burns Rebuttal, Oncor Ex. 49 at Attachment MPB-R-2. Texas Transmission Investment LLC is wholly owned by Texas Transmission Holding Company, which is owned by Borealis, GIV, and another 1 percent Investor.

⁴⁸⁹ Staff Reply Brief at 38.

In Docket No. 34077, (the merger order), the Commission accepted the identified parties' stipulation and agreement that purported to settle all issues regarding the merger. Consistent with the agreement, the Commission ordered that Oncor had to have a separate board of directors and a separate headquarters from TXU Energy Retail or Luminant.⁴⁹⁰ In addition, Oncor must protect its "financial integrity" from TXU Energy Retail and Luminant by maintaining separate books, among other things. The Commission found that the merger, coupled with the amended stipulations, was in the public interest. The Order addressed "ring-fenced entities" in the following manner:

55. Affiliate Asset Transfer Commitment. Neither Oncor Electric Delivery Holdings nor Oncor will transfer any material assets of facilities to any affiliates (*other than Oncor Electric Delivery Holdings, Oncor and their subsidiaries, which are hereinafter referred to as the "ring-fenced entities"*) other than a transfer that is on an arms' length basis consistent with the Commission's affiliate standards applicable to Oncor, regardless of whether such affiliate standards would apply to the particular transaction. (Emphasis added).⁴⁹¹

Notably absent from the order was any discussion of the tax sharing agreement's effect on future rate making.

Cities points out that utility shareholders "are loathe" to share the benefits resulting from a consolidated tax filing. Uniformly utilities take the position in rate cases that the ratepayers are not entitled to benefits from a consolidated tax filing. Cities observe that if there is no CTSA, Oncor's rates will be higher, ratepayers will pay more, Oncor's revenue will increase, and dividends paid upstream to the parent company, EFH, will increase, thus resulting in an obvious benefit to EFH and its shareholders. Therefore, in Cities' opinion, it is not surprising that Oncor has taken the position.⁴⁹²

⁴⁹⁰ Docket No. 34077, Order, FoF 44 and 45 (Feb 22, 2008).

⁴⁹¹ Docket No. 34077, Order at 10. (Feb. 22, 2008).

⁴⁹² Cities Initial Brief at 96.

Nothing in the Commission's order or in PURA suggests that it is inappropriate to apply the CTSA to a ring-fenced entity. Therefore, the ALJs find that it is appropriate for Oncor to include CTSA in FIT expense calculations.

b. Calculation of a CTSA

Referring to the history of CSAAs since Docket No. 14965, Oncor stresses that the Commission's methodology is not the "simple, consistent, easy-to-apply" method suggested by Staff and the Intervenor. This is evident in this case by the extremely different CSA results that the different experts calculated. Cities witness Mr. Kollen testified that the figure should be \$99.5 million. Staff witness Ms. Romines recommends \$114,497,035. OPC witness Ms. Blumenthal recommend \$74,865,000, almost \$15-16 million different from each other.⁴⁹³ Even Staff witness Ms. Romines stated that she could not recall any proceeding in which two parties proposed the same CSA amount.⁴⁹⁴

Pointing to PURA and P.U.C. SUBST. R. 25.231(b)(1)(D), Cities argue that ratepayers are entitled to the benefits of a CSA in this rate case. P.U.C. SUBST. R. 25.231(b)(1)(D), describes the federal income tax expense that is includable as a component of allowable expenses in the cost of service. This provision requires the consolidated tax savings be included in the operating expense component of the revenue requirement, and states:

(D) Federal income taxes on a normalized basis. Federal income taxes shall be computed according to the provisions of the Public Utility Regulatory Act §36.060.

Cities emphasize that the Commission has computed the FIT expense using a CSA for the last 10 years for Oncor and other utilities. In Docket Nos. 11735 and 22350, Cities stress, Oncor was

⁴⁹³ Kollen Direct, Cities Ex. 1 at 55; Romines Direct, Staff Ex. 3 at 16-17 and Staff Ex. 3B (Errata); Blumenthal Direct, OPC Ex. 3 at 17.

⁴⁹⁴ Oncor Ex. 97.

directed by the Commission to include a CTSA. In Docket No. 11735 (FoF Nos. 130A, 130F-130H, as modified by the Order on Rehearing), the Commission held:

130A. Based on the facts in this case, it is reasonable to calculate TU Electric's consolidated tax adjustment by allocating affiliate losses in 1987, 1988, 1989, 1990, and 1991, based on its percent of gain companies taxable income.

130F. During the test year, Texas Utilities filed a consolidated income tax return on behalf of all of its affiliates, including TU Electric.

130G. As a result of the filing of the consolidated income tax return, TU Electric's portion of the tax liability was less than it would have been had TU Electric filed *a separate income tax return as a stand-alone entity*.

130H. The Commission determined the consolidated tax savings adjustment by apportioning to TU Electric its fair share, a five-year average of the consolidated tax savings apportioned to TU Electric over the period 1987 through 1991, of the consolidated tax savings related to affiliate losses resulting from the actual filing of a consolidated income tax return.⁴⁹⁵

Likewise, Cities notes that in Docket No. 22350 (FoF Nos. 98, 98A-98D), the Commission stated the following:

98. TXU's parent TXU Corporation files annual consolidated federal income tax returns on behalf of itself and its various subsidiaries. TXU Corporation's annual consolidated taxable income for the parent company and subsidiaries is consistently less than the combined taxable incomes of its gain companies computed on a stand-alone basis. A consolidated tax savings adjustment is based upon the value of the tax shield the utility provides to the parent company and its nonregulated affiliates.

98A. TXU urged that no consolidated tax savings adjustment is required and that the company's consolidated tax savings is zero because it would be inappropriate to use data from the fifteen prior years in light of the upcoming competitive market era.

98B. In accordance with the requirements of PURA § 36.060, the Commission determined that in this proceeding it is appropriate that TXU be required to make an adjustment of \$74,574,632 to rate base calculation to reflect the company's savings from filing a consolidated income tax return.

⁴⁹⁵ Docket No. 11735, Order on Rehearing (Apr. 20, 1994). (Emphasis added.)

98C. In Docket No. 14965, the Commission found that it was appropriate to require a consolidated tax savings adjustment known as a tax shield. The Third Court of Appeals deemed the Commission's tax shield calculation methodology to be acceptable, but ultimately upheld the District Court's reversal for lack of record evidence supporting the Commission's calculation. *Central Power and Light Co. vs. Public Utility Commission*, 36 S.W.3d 547 (Tex. App. - Austin 2000, writ requested).

Cities added that the courts consistently have upheld the Commission's authority to use a CTSA despite repeated utility challenges, most recently in *Central Power and Light Co. v. Public Utility Commission*⁴⁹⁶ and *Reliant Energy, Inc. v. Public Utility Commission of Texas*.⁴⁹⁷

The ALJs find that the ratepayers are entitled to enjoy the CTSA benefits that Oncor's income generated for EFH, its holding company, over the past 15 years. However, the ALJs recognize that in 2008, EFH sold a portion of its ownership in Oncor and now only owns 80.04 % of the company. Therefore, the ALJs recommend that Oncor's CTSA be calculated at 80.04 % of the total CTSA eliminating the FIN 48 deductions and AMT deductions from the FIT, as indicated in Ms. Romines' testimony.⁴⁹⁸ The tax factor should be recalculated to reflect a taxable income rate of 35 % for all entities (.53846). This tax factor should be applied to calculate the gross-up effect on Oncor's FIT expense in recalculating the CTSA.

2. FIN 48

As previously discussed in section V.B.2., the ALJs found that the FIN 48 amounts should not have been removed from the ADFIT calculations. This matter is discussed in detail under that section and will not be repeated here. However, based on the ALJs' decision regarding FIN 48, the ALJs recommend that the FIN 48 amounts shown on Oncor's Schedule E-3 described as "Provision for Contingencies" on lines 21 and 36 be removed from the FIT expense calculations and any CTSA calculations.

⁴⁹⁶ 36 S.W.3d 547 (Tex. App. - Austin 2000, pet. denied).

⁴⁹⁷ 153 S.W.3d 174 (Tex. App. - Austin 2004, pet. denied).

⁴⁹⁸ Romines Direct, Staff Ex. 3 at 23, corrected per her Errata sheet, and her spreadsheet calculations attached as CJR-CTSA-1 Errata (Confidential)

3. Oncor's Change to a Partnership

This issue is addressed above regarding the appropriateness of imposing a CTSA, and will not be addressed again.

K. State and Local Taxes

1. Ad Valorem Taxes

No one opposed Oncor's request for ad valorem taxes, therefore the ALJs recommend the Commission approve this request.

2. Texas Gross Margin Tax

Staff requests that Oncor's Texas Gross Margin Tax (GMT) expense be reduced by \$4,757,387. Staff argues that Texas law requires affiliate companies to file a consolidated GMT return, therefore, Oncor should recover only what it owed as if Oncor had computed its liability as required by Texas law, in a consolidated tax return. As required by Texas law, EFH included Oncor in the consolidated return it filed. Oncor's share of the GMT liability was less than the amount Oncor calculated for itself as a stand-alone company.

In response, Oncor repeats its arguments regarding federal income tax expenses-that its tax sharing agreement with EFH requires it to calculate and pay EFH as if it were a stand-alone corporation. Oncor stresses that it had to pay EFH the amount it calculated as a stand-alone corporation, \$18,358,190, and argue that Ms. Jacobs' calculations are speculative. According to Oncor, no one knows how EFH and Oncor would have allocated the GMT payment if the tax sharing agreement did not exist.

Staff points out that what Oncor paid EFH is not the issue. The issue is what amount Oncor owed the State for its GMT. Because Oncor was obligated to calculate the amount it owed Texas on a consolidated basis, the amount it is entitled to recover from the ratepayers is this amount. The allocation of the GMT payment between Oncor and EFH is not the amount of the GMT Oncor owes.

Finally, while Oncor disagrees with Staff's position, Oncor states that if the Commission adopts Staff's position then Ms. Jacobs' computation of the GMT must be adjusted to reflect the increased revenues. Oncor points out that because the GMT is a revenue-related tax, if the Commission approved any additional taxable revenue it must be included in the calculation of the GMT for 2007. Staff agrees.⁴⁹⁹

The ALJs will not repeat their discussion regarding Oncor's tax sharing agreement set out in sections V.B. ADFIT and VII.J. Federal Income Tax Expenses. Ratepayers should only be required to pay the amount of the GMT that the utility is obligated by law to pay. What Oncor paid EFH is not determinative. Because Oncor was legally obligated to compute its GMT as an affiliate, the ALJs recommend that the Commission adopt Staff's position that the GMT be reduced to the amount Oncor owed as an affiliate. The exact amount will need to be computed once the Commission approves Oncor's taxable revenue for 2007.

3. Municipal Franchise Fees⁵⁰⁰

Oncor requested recovery of municipal franchise fees of \$253,884,976. Staff challenged this amount and recommended a reduction of \$5,696,931. According to Staff, Oncor is not entitled to recover the 5 % increase in the franchise fee rate that it agreed to pay pursuant to an agreement with Cities.⁵⁰¹ PURA § 33.008(b) specifies how to calculate municipal franchise fees owed by a utility to

⁴⁹⁹ Staff Reply Brief at 49.

⁵⁰⁰ Oncor proposed a rider for franchise fees, called Rider FFCRF, franchise fee cost recovery factor, which is addressed in section VIII. H.

⁵⁰¹ Jacobs Direct, Staff Ex. 5 at 26-27.

municipalities within its service territory.⁵⁰² Because Oncor agreed to pay its municipalities 5 % more than the 2005 effective rate calculated pursuant to PURA § 33.008(b), Staff maintains that extra amount is not reasonable and necessary to provide service to the public.⁵⁰³

Oncor disagrees with Ms. Jacobs' interpretation of PURA § 33.008 and insists subsection (f)⁵⁰⁴ allows it to contract with municipalities and to recover this amount from the ratepayers. Oncor witness David Sigler explained that Oncor entered into a settlement agreement with the cities it serves that increased its existing franchise fees by 5 %.⁵⁰⁵ According to Oncor, PURA § 33.008(c)⁵⁰⁶ allows Oncor to recover these charges as reasonable and necessary operating expenses.

The ALJs agree with Oncor's interpretation of PURA § 33.008. PURA allows each municipality to impose a franchise fee on an electric utility in exchange for allowing the utility to use its streets and other public ways in providing distribution services.⁵⁰⁷ Under PURA, the cities have

⁵⁰² Subsection (b) states that:

The compensation a municipality may collect from each electric utility, transmission and distribution utility, municipally owned utility, or electric cooperative providing distribution service shall be equal to the charge per kilowatt hour determined for 1998 multiplied times the number of kilowatt hours delivered within the municipality's boundaries.

⁵⁰³ Tr. Vol. 7 at 1241-1242 (Jan. 23, 2009).

⁵⁰⁴ PURA § 33.008(f) states:

(f) Notwithstanding any other provision of this section, on the expiration of a franchise agreement existing on September 1, 1999, an electric utility, transmission and distribution utility, municipally owned utility, or electric cooperative and a municipality may mutually agree to a different level of compensation or to a different method for determining the amount the municipality may charge for the use of a municipal street, alley, or public way in connection with the delivery of electricity at retail within the municipality.

⁵⁰⁵ Sigler Direct, Oncor Ex. 26 at 8.

⁵⁰⁶ PURA § 33.008 (c) states:

(c) The municipal franchise charges authorized by this section shall be considered a reasonable and necessary operating expense of each electric utility, transmission and distribution utility, municipally owned utility, or electric cooperative that is subject to a charge under this section. The charge shall be included in the nonbypassable delivery charges that a customer's retail electric provider must pay under Section 39.107 to the utility serving the customer.

⁵⁰⁷ PURA § 33.008(a).