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IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
Petition of Piedmont Natural Gas Company, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs	)	**DOCKET NO. 09-00104**

SUPPLEMENTAL RESPONSES AND OBJECTIONS OF THE CONSUMER ADVOCATE TO PIEDMONT'S DISCOVERY REQUESTS

Robert E. Cooper, Jr., Attorney General and Reporter for the State of Tennessee, by and through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), as required by TRA Rules and the Tennessee Rules of Civil Procedure, hereby submits its supplemental responses and objections to the first discovery request of Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company").

GENERAL OBJECTIONS

The Consumer Advocate reiterates and renews its General Objections previously raised in its Original Responses to the Discovery Requests submitted by Piedmont. Those General Objections are:

1. The Consumer Advocate objects to the definitions and instructions contained in the Company's interrogatories to the extent that the definitions and instructions attempt to impose on the Consumer Advocate a burden or obligation greater than that required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

2. The Consumer Advocate objects to the interrogatories to the extent they call for information and the production of documents which are protected from disclosure by the

attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's interrogatories to the extent they seek information not related to the subject matter involved in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, the Consumer Advocate does not concede that such information is relevant, material or admissible in evidence. The Consumer Advocate reserves all rights to object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to impose on the Consumer Advocate obligations to supplement its responses beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

6. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the Company's own possession, custody or control. It is unduly burdensome and oppressive to require the Consumer Advocate to respond or produce documents that are equally available to the Company.

7. The Consumer Advocate's objections and responses to these requests are based on information now known to it. The Consumer Advocate reserves the right to amend, modify or supplement its objections and responses if it learns of new information.

8. The Consumer Advocate's responses to these requests are made without waiving or intending to waive the right to object to the use of any information provided in response to any subsequent proceeding or trial of this or any other action. The Consumer Advocate's responses to these requests are also not a waiver of any of the foregoing objections or any objections it has made or may make with respect to any similar, related, or future data request, and the Consumer Advocate specifically reserves the right to interpose any objection to further requests notwithstanding any response or lack of objection made in this response.

9. The Consumer Advocate will supplement its responses in accordance with the requirements of state law.

10. The Consumer Advocate expressly incorporates these general objections into its responses set forth below.

Subject to and without waiving any objections stated above the Consumer Advocate now submits these supplemental responses to Piedmont's specific requests as follows:

DISCOVERY RESPONSES AND OBJECTIONS

1. State the Consumer Advocate's position on what is the most appropriate mechanism or financial incentive to ensure that Piedmont's financial incentives are aligned with the state's energy conservation policy as set out in 2009 Public Act 531, Section 53.

ORIGINAL RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate's work on this

issue is on-going; consequently, it reserves the right to supplement and produce additional information as it becomes available. The Consumer Advocate's analysis in this case is fact intensive and detail oriented. The Consumer Advocate's analysis and opinion(s) are dependent upon information which is in the hands of Piedmont and which has not yet been made available to the Consumer Advocate.

Subject to and without waiving these objections and in an effort to avoid delaying this proceeding the Consumer Advocate responds as follows:

See the *Statement of the Consumer Advocate on Implementing Conservation Measures in Tennessee* filed in Docket 09-00065 on September 25, 2009. Moreover, the subject-matter of this docket, namely the implementation of the General Assembly's new energy conservation policy enumerated in 2009 Public Act 531, Section 53, is controlled by the following:

> The general assembly declares that the policy of this state is that the Tennessee regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the authority has rate making authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.

The new policy neither requires nor forbids decoupling mechanisms to promote conservation. The natural gas industry, collectively, has submitted that the new policy should be implemented on a case by case basis, taking into account the differing operating conditions of the utilities and differing needs of customers and that the Authority should avoid a "one size fits all" policy. *See* the individual comments of Chattanooga Gas Company, Atmos Energy Corporation and Piedmont in Docket 09-00065 filed August 3-4, 2009. Thus, the appropriate mechanism, according to the state's natural gas industry, is a factually intensive and detail oriented subject-

matter and dependent upon the circumstances of the individual utility. At this time, the Consumer Advocate's position is reliant upon Piedmont's company specific information and information showing both the short and long term financial impact of the Piedmont's proposal, which is currently not within the record or within the Consumer Advocate's possession.

The Consumer Advocate's position on this issue is to seek a policy which will encourage consumer energy conservation while allowing the utility to continue to have the opportunity to earn a fair return. Piedmont's proposal is a decoupling mechanism which the Company submits fulfills the State's policy. However, given the lack of specific information in the record, the Consumer Advocate is not satisfied at this time Piedmont's proposal is the appropriate policy tool to implement the State's new energy conservation policy.

Proponents of decoupling mechanisms have generally linked the concept of decoupling to energy conservation to the extent gas utilities promote decoupling mechanisms and conservation as one in the same. Decoupling has been described as a way to break the link between sales volume and utility revenues in order to allow a utility to encourage conservation. The theory sounds logical and laudable. However, the practical application of decoupling, as sought by the natural gas industry, has been subject to dispute and controversy. For example, the Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached at Tab A. In another example, the New Mexico Public Regulation Commission adopted the conclusions of the Hearing Officer rejecting a proposed decoupling mechanism that was characterized as designed to provide a "financial windfall" for utilities

rather than making them financially neutral to conservation programs. An excerpt of the Hearing Examiner's order is attached at Tab B.[1]

In Rhode Island, decoupling has been rejected for natural gas consumers. The Commission noted that the financial benefits to the utility from decoupling were well documented in the record with information showing the utility would have collected an additional $34 million over the preceding four years had the mechanism been in place. However, any benefit accrued by consumers from decoupling would be based on speculation. A copy of the Commission's order is attached at Tab C. *See* pp. 57-72 for discussion and ruling.

In the context of shifting business risk to consumers, North Carolina is an example of a state in which a decoupling mechanism produced large rate increases while insulating Piedmont from economic risk. In 2005, the North Carolina Utilities Commission allowed Piedmont to implement a decoupling mechanism, known as the Customer Utilization Tracker ("CUT"), on an experimental basis. According to a report written by the North Carolina Utilities Commission and submitted to the Joint Legislative Utility Review Committee of the state legislature on October 2, 2008, the CUT produced $99.2 million dollars in additional rates owed to Piedmont by consumers in a three year period. Roughly half of this amount was attributable to price elasticity rather than the effects of the utility conservation program. The remaining half of the CUT's revenues was attributable to weather as the WNA in North Carolina was discontinued when the CUT was adopted. A copy of the report is attached to the Consumer Advocate's *Addendum to the Memorandum in Support of Motion Requesting Permission to Issue More Than Forty Discovery Requests*, filed in this docket on October 13, 2009.

[1] Complete copies of the Hearing Examiners Ruling and the New Mexico Commission Order adopting the ruling is attached to Mike Chrysler's Direct Testimony in Docket 07-00105, filed August 22, 2007 and publicly available through the TRA's electronic website.

The North Carolina Utilities Commission report states that warmer than usual weather and the effects of Hurricane Katrina and Hurricane Rita on natural gas prices contributed to financial impact of the CUT. The Consumer Advocate would note the impact of weather, natural gas prices and of the aforementioned hurricanes were equally felt in Tennessee. However, at no point during the three year period covered by the North Carolina report did Piedmont file a rate case in Tennessee.

Another example that is notable is in neighboring Virginia. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). A copy of the order is attached at Tab D. The pre-filed testimony of the Virginia Commission Staff which contains their findings is attached at Tab E. The Virginia Commission noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007. However, the Act prevented the Commission from considering these concerns. The Authority is this matter has no similar legal constraint.

The decoupling debate has been on-going in Tennessee before the Authority. A decoupling mechanism proposed by Atmos Energy Corporation, which shares the basic framework of Piedmont's proposal, was rejected by the Authority as it removes any incentive for a utility to control fixed costs. Docket 05-00258, *Transcript of Proceedings*, October 26, 2006,

pp. 6-7, 13 (*See* also Director Miller's Motion which is attached to the referenced transcript). In addition, Piedmont's decoupling proposal does not account for the additional revenue created by customer growth. The pre-filed written testimony on behalf of the Consumer Advocate concerning the off-setting effect to margin loss per customer, and even to an extent allowing over-earning in revenues and return on equity, from revenue generated from customer growth is publicly available online at the TRA website. See the pre-filed Direct Testimony of Mike Chrysler in Docket 07-00105 filed on August 22, 2007; See also Rebuttal Testimony of Daniel McCormac in Docket 05-00258 filed on August 18, 2006. Recently, Atmos has acknowledged historical customer growth rates have offset the declining revenue per customer due to conservation while noting that customer growth had declined recently due to the downturn in the economy. *See* the sworn pre-filed Direct Testimony of Mr. Kevin Akers on behalf of Atmos Energy in Docket 08-00197 filed October 15, 2008. On page 4 at lines 1-2, Mr. Akers states historic growth rates have been "sufficient to overcome declining customer usage due to energy conservation and more efficient homes and appliances."

The decoupling debate is not confined to Tennessee or a few other states. See the attached presentation given by Ken Costello, senior economist for the National Regulatory Research Institute at Tab F. Mr. Costello's presentation provides an overview of the national debate on decoupling and examines the arguments both for and against decoupling. Other states have adopted modified decoupling mechanisms or adopted alternatives to decoupling in order to encourage conservation. The Colorado Public Utilities Commission modified a decoupling mechanism in order for both consumers and the utility to share risk and to encourage the utility to control costs. The order is attached at Tab G. *See* pages 11-13. New Jersey has adopted a modified mechanism. The order is attached at Tab H.

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: Dr. David Dismukes, a consultant hired by the Consumer Advocate, will provide testimony concerning the Consumer Advocate's proposals. The Consumer Advocate intends to present testimony which proposes a performance based conservation program which will allow Piedmont to be made whole for lost revenue attributable to the efforts of Company sponsored conservation programs. In the alternative, if the TRA determines Piedmont has proven a decoupling mechanism is warranted, the Consumer Advocate intends to propose a decoupling mechanism, similar to that approved in Colorado, which has a threshold of 0.9 percent of declining usage that must be exceeded before a rate adjustment is necessary. The Colorado Order has been provided previously.

If the TRA does not accept the Colorado model, Dr. Dismukes is expected to recommend adoption of a total revenue recovery balance cap for the decoupling mechanism. In addition, Dr. Dismukes will recommend that should the TRA decide to implement a decoupling mechanism, the TRA should do so only after a rate case. The minimum filing requirements for this rate case should include:

- the Company's determination of its proposed initial target revenues (margins) per customer for each rate class;
- the factors that the Company proposes to use to annually adjust its target revenues (margins) for each rate class;
- the manner in which the Company's proposed mechanism treats customers receiving new distribution service during a particular year, to the extent that the Company determines

that the costs of providing service to new customers differs from the costs of providing service to existing customers;

- a tariff showing the manner in which the Company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;
- include a total revenue decoupling deferral account balance cap that is no greater than 2.0 percent of total base revenues;
- the manner in which the Company has taken into account in the determination of its proposed ROE, the effect that implementation of its proposed decoupling mechanism will have on its risk profile;
- a full analysis of the potential and cost-effective energy efficiency opportunities in its service territory;
- a full energy efficiency plan that includes cost effectiveness findings for each major energy efficiency measure/program being proposed; and a proposed energy efficiency/revenue decoupling review process including goals, targets, and benchmarks.

Furthermore, Dr. Dismukes intends to testify that any decoupling mechanism approved be re-evaluated in three years with the presumption the mechanism will not be renewed unless the Company proves otherwise. Dr. Dismukes analysis is on-going. The Consumer Advocate reserves the right to supplement this response.

2. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

ORIGINAL RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

SUPPLEMENTAL RESPONSE:

Without waiving its prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Discovery Request #1 and Attachment 2. The Consumer Advocate reserves the right to supplement when information becomes available.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

ORIGINAL RESPONSE:

The Consumer Advocate, consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony in support of a modified decoupling mechanism or in support of an alternative proposal. Mr. Buckner's opinion will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

SUPPLEMENTAL RESPONSE:

Without waiving its prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Discovery Request #1.

At this time, Dr. Chris Klein, a consultant, is expected to address how Piedmont's proposed decoupling mechanism shifts business risk from the Company to consumers and necessitates a reduction in ROE. His analysis is on-going at this time. Terry Buckner is expected to testify regarding the appropriate benchmark for the MDT should the TRA determine to approve the Company's proposed decoupling mechanism or a modified decoupling mechanism.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

ORIGINAL RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to

call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

SUPPLEMENTAL RESPONSE:

Without waiving its prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Discovery Request #1.

3. If the Consumer Advocate's position is that an alternative mechanism may be more appropriate to fulfill the state's energy conservation policy as set out in 2009 Public Act 531, Section 53, identify the alternative mechanism(s) under the Consumer's Advocate's consideration.

ORIGINAL RESPONSE:

See Response to Request 1.

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Request 1.

4. With respect to the position and any identified alternative mechanism stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

ORIGINAL RESPONSE:

See Response and objections to Request 1 and 2(a).

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Request 1. See also Attachment 2.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

ORIGINAL RESPONSE:

See Response and objections to Request 1 and Request 2(b).

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Request 1. See also Attachment 2.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

ORIGINAL RESPONSE:

See Response and objections to Request 1 and Request 2(c).

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Request 1. See also Attachment 2.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

ORIGINAL RESPONSE:

See Response and objections to Request 1 and Request 2(d).

SUPPLEMENTAL RESPONSE

Without waiving prior objections, the Consumer Advocate supplements as follows: See Original Response and Supplemental Response to Request 1. See also Attachment 2.

6. With respect to the position stated in response to the foregoing data request:

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

ORIGINAL RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on what issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner will provide testimony either agreeing with Piedmont's proposed benchmark or proposing an alternative. Any opinion put forth by Mr. Buckner will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: Terry Buckner is expected to provide testimony supporting a benchmark based on recent customer usage data. His analysis is on-going.

7. State the Consumer Advocate's position on the issue whether Piedmont's earnings should be evaluated prior to the implementation of a decoupling mechanism.

ORIGINAL RESPONSE:

Piedmont has not had a rate case since 2003. It is incumbent upon the Authority to examine this issue, prior to making a determination as to the appropriate mechanism to carry out 2009 Public Act 531, Section 53. Moreover, the TRA must still determine whether this is an appropriate proceeding under 2009 Public Act 531, Section 53. Under Tennessee law, rates are required to be just and reasonable. The decoupling proposal of Piedmont effectively ends the concept of "regulatory lag" in traditional rate-making for residential consumers, the rates of which are already adjusted for weather, the cost of natural gas and uncollectible accounts.

Moreover, an examination of utility earnings in the context of decoupling is essential. The Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached with those documents addressing Response to Request 1.

In the context of the revenue produced by decoupling, such mechanisms have been shown to increase utility earnings. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism proposed in Virginia pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission fully discusses the concerns and opposition of the

Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). Testimony filed by the Virginia Commission Staff noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007 while VNG's return on equity earned, rather than authorized, would increase. A copy of the Virginia Commission Staff pre-filed testimony is attached at Tab E.

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Supplemental Response to Discovery Request 1. In addition, Terry Buckner is expected to offer testimony that a rate case is the most appropriate proceeding to implement a decoupling mechanism. Mr. Buckner is also expected to testify that at a minimum, Piedmont's earnings should be reviewed prior to implementing a decoupling mechanism.

9. State the Consumer Advocate's position on whether the implementation of a decoupling mechanism lowers the business risk for Piedmont, thereby justifying an adjustment to its rate of return.

ORIGINAL RESPONSE:

The Consumer Advocate submits that if consumers use less natural gas for any reason, Piedmont's proposed decoupling mechanism will allow the Company to raise the bills of consumers. Thus, the mechanism has the effect of guaranteeing revenues from residential consumers and shielding Piedmont from declining revenue for any economic or business reason. This has the effect of shifting business risk from the utility to consumers. This principle has been recognized in other states in terms of decoupling. This principle has been recognized and

quantified by an expert testifying on behalf of Chattanooga Gas Company. *See* Pre-filed Direct Testimony of Dr. Roger A. Morin filed in TRA Docket 06-00175 on June 30, 2006.

In Connecticut, decoupling was rejected. In doing so, the Department of Public Utility Control stated that approval of a decoupling mechanism would require at least a 100 basis point reduction to the ROE to provide the commensurate risk compensation to consumers. A copy of the order is attached at Tab I. *See* pages 90-91. In Illinois, a decoupling mechanism was approved. However, based on the risk reduction of the mechanism, the Illinois Commerce Commission reduced ROE by ten basis points for a gas utility. A copy of the order is attached at Tab J. *See* page 101. The New York Public Service Commission adopted a decoupling mechanism, but also adjusted the ROE by 10 basis points to reflect the lower business risk to the utility. A copy of this order is attached Tab K. *See* pages 32-34. When decoupling mechanisms have been approved for electric utilities, state commissions have adjusted the ROE. *See* copies of orders from Vermont at Tab L and the District of Columbia and Tab M.

SUPPLEMENTAL RESPONSE:

Without waiving prior objections, the Consumer Advocate supplements as follows: See Supplemental Response to Discovery Request 10.

10. With respect to the position stated in response to the foregoing data request:

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

ORIGINAL RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate

responds as follows: Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket. The Consumer Advocate reserves the right to supplement this response as information becomes available to it.

SUPPLEMENTAL RESPONSE:

Dr. Chris Kline and Dr. Dismukes are expected to provide testimony on this issue. Dr. Dismukes submits that decoupling mechanisms shifts business risk from utilities to consumers. Dr. Kline addresses the need for an adjustment Piedmont's ROE should the TRA approve a decoupling mechanism. His analysis is on-going. See attachment to supplemental response Discovery Request 2, Attachment 2 and the original response to Discovery Request 9.

(e) Identify what method or evaluation tools the Consumer Advocate contends should be utilized to quantify an adjustment to Piedmont's rate of return and why such methods or tools are appropriate.

ORIGINAL RESPONSE:

Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed.

SUPPLEMENTAL RESPONSE:

Dr. Chris Kline's analysis is on-going. The Consumer Advocate reserves the right to supplement this response.

11. State the Consumer Advocate's position on the issue whether Piedmont should be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs.

ORIGINAL RESPONSE:

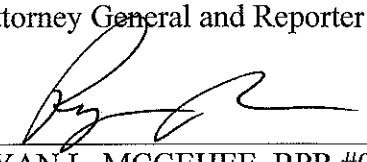
The Consumer Advocate would submit that specific, verifiable, measureable energy efficiency goals and/or benchmarks are essential to the success of any conservation program. Utility conservation programs are the lynch pin of most, if not all, decoupling proposals. If conservation programs are not cost-effective, producing verifiable and measurable results, then there is simply no logical justification for a decoupling mechanism. Further, Piedmont's proposal in this matter includes mandatory consumer funding of conservation programs. If funds from consumers are collected for these programs, they must produce cost-effective, verifiable and measurable results. In essence, as an expense category, such expenditures must be prudent in the context of just and reasonable rates.

SUPPLEMENTAL RESPONSE:

Dr. Dismukes is expected to provide testimony regarding the position stated in the original response to this discovery request and assess the cost effectiveness of the Company's proposed conservation programs. See also Attachment 2. The Consumer Advocate reserves the right to supplement this response and other related responses.

Respectfully Submitted,

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Attorney General and Reporter



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Dated: ~~November~~ December 2, 2009.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing foregoing was served via U.S. Mail or electronic mail upon:

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This the 2 day of December, 2009.

Ryan L. McGehee
Assistant Attorney General

Revenue Decoupling

A Policy Brief of the Electricity Consumers Resource Council

Every complex problem has a simple solution too good to be true, and it usually is.

Attributed to H.L. Mencken

Introduction

For over two decades advocates of ratepayer-funded energy efficiency and load reduction programs have recommended that the 'link' between utility's revenues and its sales be 'decoupled' to eliminate a utility's disincentive to sponsor such programs. The argument is that the combination of the utility management's fiduciary duty to shareholders and the use of rates based on a revenue requirement, that includes sales in its calculation, discourages utilities from being competent vendors of energy efficiency and load reduction services.

Revenue decoupling (RD) is generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's revenues on sales. It is adopted with the intent of removing the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility's T&D system. In regulatory parlance, RD takes the form of a tracker or attrition allowance in which authorized per customer margins are subject to a true-up mechanism to maintain or cap a given level of revenues or revenues per customer. Variations from the targeted sales or revenues are subsequently recaptured from ratepayers through a surcharge or credit.

In a significant departure from traditional cost-of-service principles, which historically provides utilities with only the opportunity to earn a fair return, RD guarantees actual earnings at the level of authorized earnings. Under RD, a utility is indifferent to the impact of sales levels or when the sales occur because of changing economic conditions, weather, or new technologies.

ELCON members are strong supporters of energy efficiency and are world-class practitioners of innovative technologies that reduce their energy costs to improve their competitiveness. But ELCON strongly opposes decoupling because it disrupts and distorts the utility core business functions and is not a particularly effective way of promoting energy efficiency or anything of benefit to customers. Time and time again decoupling has been tried in several states, only to be suspended because it unduly interferes with the overall regulatory process. ELCON believes that there are other ways to promote energy efficiency and load reduction services that have proven to be more effective. This paper describes the simple mechanics of decoupling, why decoupling has historically failed and is not likely to be any more effective in future applications, and proposes alternative regulatory policies that more effectively focus on market transformation and the effective delivery of demand-side services.

The Mechanics of Revenue Decoupling
An Illustrated Example of An Annualized RD Mechanism[1]

Base Year Assumptions

	Year One	Year Two
Utility's Operating Costs (A)	$4 billion	$4 billion
Utility's Rate Base (B)	$5 billion	$5 billion
Authorized Return to Equity Owners (ROE)	10%	10%
Authorized Earnings to Equity Owners (C) (10% of $5 billion)	$500 million	$500 million
Utility's Authorized Revenue (A + C)	$4.5 billion	$4.5 billion
RD Balance Account (D)	0	$45 million
Baseline Sales (E)	45,000 GWh	45,000 GWh
Base Rate per KWh (A + C)/E	$0.10	$0.10
Effective Rate per KWh (F) (A + C + D)/E	$0.10	$0.101

Actual Sales Year

Actual Sales (G) (1% diviation from baseline forecast)	44,550 GWh 1% Below Baseline	45,450 GWh 1% Above Baseline
Actual Revenues Collected (H) (F × G)	$4,455 million	$4,590 million
Unadjusted Earnings to Equity Owners (I) (H minus A)	$455 million	$590 million
Reported ('Authorized') Earnings (C)	$500 million	$500 million
Actual ROE (I/B)	9.1% Reduction of 90 basis points	11.8% Increase of 180 basis points
Reported ('Authorized') ROE	10%	10%
End-of-Year Balance Account (D) (A + C) minus H	$45 million	($90 million)

[1] This is a simplified example of revenue decoupling that assumes no variable T&D costs or change in the number of customers. Also, tax implications and accounting for price elasticity are ignored.

How Decoupling Works

RD mechanisms can take several forms but all accomplish the same thing: customer rates are automatically adjusted to immunize utility earnings from sales fluctuations.

The first example is illustrated on the spreadsheet on page 2. It provides a simplified form of mechanism in which true-ups are done on an annual or multi-year basis. The process usually starts with a baseline determination of a utility's revenues that may include the anticipated consequences of a DSM program. This is the 'base case' in the illustration.

The illustration holds this baseline constant over a two-year period. In the first year, actual sales are 1% below the baseline amount; in the second year actual sales are 1% above the baseline. The result is a revenue shortfall in the first year of $45 million. Absent any other offsetting revenue recovery mechanism, this shortfall reduces earnings to equity owners and the expected ROE. This illustrates a main argument of proponents of RD that any small reduction in sales can produce a significant reduction in the utility's allowed earnings. In the example, the actual ROE is 9.1%, a reduction of 90 basis points from the allowed ROE of 10%.

Applying the RD mechanism in the second year, revenues are adjusted by increasing the customer rate upwards to ensure that sufficient revenues are collected to achieve the allowed ROE. However, actual sales are 1% above the baseline amount and the utility over collects $90 million. The actual ROE is 11.8% or 180 basis points above the allowed ROE. This simple example highlights the potential year-to-year volatility of the RD mechanism.

With compounding economic events (e.g., recessions), the accrual account can grow quite large unless more frequent rate cases or true-ups are ordered. RD mechanisms tried in the past tended to generate substantial accruals that quickly became a dilemma for regulators and a burden for ratepayers.

The second example (on page 4) illustrates decoupling on a revenue-per-customer (RPC) basis. The base year revenue collected per customer (RPC) on an average customer class basis is fixed, and the annual charge is then typically allocated on a monthly, normalized basis over a reference year. Each month the actual revenues collected per ratepayer are compared to the allowed monthly RPC and the difference is either credited or debited to a balancing account. Customers would still be billed on a per-unit consumption basis, but the rate would be trued-up based on actual revenues collected per customer. This prevents the utility from earning additional profit from unexpected sales but also ensures that the utility recovers its costs resulting from unexpected customer growth. For unexpected declines in sales per customer and / or declines in the number of customers, the mechanism works the same way. Under- or over-recoveries in any month are automatically trued-up the following month or at the end of the year.

The RPC mechanism highlights the 'blunt instrument' nature of decoupling. The utility is made whole for earnings losses that go beyond the limited losses caused solely by energy efficiency and load reduction programs. The net effect of the true-up mechanism is to put the utility's revenue stream on autopilot. This isolates utility management and equity owners from the normal business risk inherent to the utility industry, notwithstanding that the existence of a ROE is to reward equity owners with a return on their investment that includes a sizeable risk premium commensurate with the business risk. In short, an RD mechanism makes retail electric distribution service virtually risk free for utilities.

The Mechanics of Revenue Decoupling
An Illustrated Example of Revenue-Per-Customer (RPC) Mechanism With Monthly True-Ups [2]

Base Year Allowed RPC
For a Base Year Month

Base Year Rate per kWh (A)	$0.10
Base Year (Month) Sales in kWh (B)	1 billion
Base Year (Month) Revenue (A x B)	$100 million
Base Year Number of Customers (C)	1,000,000
Allowed RPC (A x B)/C	$100

Calculation of Revenue Adjustment
For A Single Month

Base Year Rate per kWh (A)	$0.10
Actual Sales for the Month (D) 5% Reduction from Baseline (B)	0.95 billion
Actual Revenues for the Month (E) (A x D)	$ 95 million
Actual Number of Customers (F)	1,010,000
Allowed RPC	$100
Allowed Revenues (G) (F x E)	$101 million
Revenue Adjustment (H) (G – E)	$6 million
Forecasted Next Month Sales (I)	1.0 billion
Rate Adjustment (True-Up) (H/I)	$0.006
This adjustment is added to rates for sales the following month, or at the end the year.	

[2] This example assumes that sales per customer decline but the number of customers grows.

ELCON Position & Recommendations

A. *Decoupling Promotes Mediocrity In The Management Of A Utility.*

The primary function of a regulated electric utility is and will always be to efficiently sell and deliver electric energy to customers. For investor-owned utilities, the profit-motive is a legitimate and practical means to incent utility managers to operate their business in a competent and efficient manner. There also need not be any conflict with 'unselling' the business' primary product by offering energy efficiency and load reduction services.

Firms in many industries meet the competition by selling a range of products competing for different segments of the market share. But in regulated industries, such as electric utilities, rate structures and regulatory policies may have to be aligned to make this work. The attractiveness of revenue decoupling to many utility executives is that it will immunize the company's earnings or revenues from sales fluctuations. This can only promote mediocrity and indifference to the utility's core business, a situation that should not be in the best interests of either advocates of selling or unselling the energy product.

B. *Decoupling Shifts Significant Business Risk From Shareholders To Consumers With Only Dubious Opportunities For Net Increases In Consumer Benefits.*

Decoupling does not create an economic incentive promoting greater energy efficiency or load reduction. It establishes, at best, utility indifference to these objectives. At the same time, it undermines customer efficiency efforts and muddles price signals to consumers. For example, conservation efforts are rewarded with higher future rates, while excessive consumption paradoxically produces bill credits. This is a cynical way to induce energy conservation that is not likely to be effective. Decoupling only removes an alleged disincentive while at the same time creating real disincentives for competent management of the business. The Maine Public Utilities Commission stated in 2004:

> Revenue decoupling does not … provide any positive incentive for utilities to promote or support energy efficiency or conservation programs; it only makes them financially neutral to such activities.

There is growing national concern that utilities are under-investing in infrastructure and not adequately planning for the future needs of their customers. Why this situation has been allowed to happen is troublesome given that for many utilities their allowed return is already above their actual cost of capital. Regulatory policies need to refocus utility management on its core responsibilities to efficiently sell and deliver electric energy and to make prudent long-term investments. Regulators must not bargain with their utilities from a weak position that assumes that financial incentives in excess of a reasonable return is necessary for ordinary business behavior. For all practical purposes RD mechanisms put utility management on autopilot and this will only further encourage them to ignore their core business, the value of economic development in their franchise area, and the broader needs of the utility's customers. These objectives are at least as important as any attempt to only eliminate a disincentive to energy efficiency.

An important feature of the financial structure of investor-owned utilities is that the utility's shareholders assume normal business risk. This is the risk-reward model that pervades private businesses in the US and global economies. Shareholders are best able to diversify business risk and market-based economies strive on this basis. Utility ratepayers are least able to do so; yet it is the expressed intent of RD mechanisms to shift risk from shareholders to consumers, a radical

departure from standard regulatory policy intended to balance the interests of equity owners and ratepayers.

Proponents of RD mechanisms almost always support preserving the utility's allowed return on equity at a level that assumes the shareholders retain such risk. Getting utility management to buy into the scheme would be difficult otherwise. Hence RD mechanisms are an attempt to force energy efficiency and load reduction programs at any cost and with no regard for the economic welfare of the impacted ratepayers.

Using RD mechanisms in conjunction with general rate cases also can have a ratchet effect on revenues and rates to the extent the RD adjustments in between rate cases are memorialized in the next rate case. For these and other reasons there is ample justification for dismissing the alleged value of RD mechanisms in ratemaking.

C. *Decoupling Eliminates A Utility's Financial Incentive To Support Economic Development Within Its Franchise Area. This Includes The Incentive To Support The Well Being of Manufacturers And Their Workforce.*

Promoting growth in sales through the addition and expansion of business enterprises is a key area where utility financial incentives and local public interests are precisely aligned. Revenue decoupling breaks that alignment. While its sole purpose is the elimination of the alleged disincentive to a utility's active support for energy efficiency and load reduction programs, it also eliminates the financial incentive to actively promote the economic development of the utility's franchise area. More specifically, it neutralizes the financial incentive to attract new commercial and industrial businesses—and new job opportunities—to the utility's franchise area, and to support the well being of its existing commercial and industrial customers, unless those customer classes are specifically exempt from the RD mechanism. ELCON believes that regulatory policies should promote greater customer focus, not less.

D. *Revenue Decoupling Mechanisms Tend To Address 'Lost Revenues' And Not The Real Issue, Which Is Lost Profits.*

To the extent that rates based on sales create a disincentive for utility efforts to promote energy efficiency and load reduction, the problem is in the rate design and the failure to abide by long-standing cost-of-service ratemaking principles. RD mechanisms have the effect of shifting the recovery of the utility's fixed costs into the customer (or demand) charge of base rates where they belonged in the first place. Thus, from one perspective, RD can be viewed as a stopgap ratemaking mechanism to overcome rate designs that have been used and abused for other misguided policy objectives such as the imposition of cross-class subsidies and stranded cost recovery. The complexity of RD mechanisms also makes them very expensive to administer and regulate. This greatly reduces the transparency of the ratemaking process and, even more so in the public mind, reduces the logic of cost causation.

The ability of a utility to have the opportunity to earn a fair return on assets that are prudently incurred and that remain used and useful is a grand compromise of regulation that has withstood the test of over a hundred years of practice. Any increased opportunity for a utility to earn its authorized rate of return must be commensurate with an increase in business risk, not the reverse!

There is no inherent inconsistency that a utility would both sell and 'unsell' electric energy if rates are appropriately designed for the different services. Selling competing products and services is a common business choice and need not be a moral dilemma only for utility executives. There are examples of state ratemaking practices such as shareholder performance incentives that create

more explicit economic inducements for promoting energy efficiency and load reduction. These practices avoid the collateral damage created by the 'blunt instrument' nature of RD mechanisms.

E. The First And Most Important Step Regulators Can Take To Promote Energy Efficiency Is To Send The Proper Price Signals To Each Customer Class.

In the short term, seasonal weather variations are the predominant cause of variations from sales forecasts. For example, unseasonably mild winters can lead to below forecast sales. In the longer term, economic growth in the form of increased customer accounts and usage drive electric sales and revenue growth. Ratepayer investments in energy efficiency gradually moderate energy sales growth. Load shifting efforts from peak to off-peak periods may not reduce overall kWh sales, but should lower the cost of supplying that energy.

Thus the first and most important step regulators can take to ensure that ratepayers themselves are induced to make energy efficient investments and behavioral changes is to implement retail rates that send the proper price signals to each customer class. This includes allocation of fixed costs to customer (or 'demand') charges and time-variant energy charges. The Energy Policy Act of 2005 directs the states to consider expanded deployment of time-based pricing and advanced metering, and ELCON strongly encourages states to pursue this path to more efficient pricing rather than the futile pursuit of decoupling mechanisms.

Large industrial customers are almost always on some form of time-of-use rate, with a demand charge, and this rate structure is extremely valuable to the customer for evaluating the cost-effectiveness of energy efficiency improvements in their manufacturing facilities. Large industrial customers do not look for guidance from utilities on how to co-optimize their energy consumption and manufacturing activities, and 'decoupling' does not make utilities experts in these matters. By further blunting price signals to ratepayers, RD mechanisms actually undermine incentives for customers to invest in more efficient appliances and equipment because the reward for reducing consumption is higher rates in the future. ELCON members believe that a utility's fundamental responsibility is to efficiently sell and deliver energy at the lowest possible cost, and appropriate price signals are an essential component of that objective.

F. Several States Have Successfully Used Alternative Entities—Including Government Agencies—For Unselling Energy. This Creates An Entity Whose Sole Mission Is To Promote Energy Efficiency, And Retains A Separate Entity Whose Responsibility Is To Efficiently Sell And Deliver Energy.

Some states believe that simultaneously selling and unselling electric energy is a real conflict of interest and have assigned the administration of the unselling function to an independent entity or agency whose mission is dedicated to promoting energy efficiency and load reduction. This policy recognizes that another entity—the utility—must be responsible for efficiently selling and delivering electric energy. States that have taken this path are Wisconsin, Maine, New Jersey, Ohio, Vermont, Oregon, New York, and Connecticut.

In New York, for example, the New York State Energy and Research Development Authority (NYSERDA) is charged with the responsibility for demand-side programs, and is funded by a systems benefit charge that is collected by the utilities. Wisconsin established *Focus On Energy* as a public-private partnership offering energy information and services to residential, business, and industrial customers throughout the state. There services are delivered by a group of firms contracted by the Wisconsin Department of Administration's Division of Energy.



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AN ECONOMIC ANALYSIS OF CONSUMER RESPONSE TO NATURAL GAS PRICES

FREDERICK JOUTZ AND ROBERT P. TROST

PREPARED FOR THE AMERICAN GAS ASSOCIATION
MARCH, 2007



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An Economic Analysis of

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Executive Summary

Introduction and Key Findings

The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. Some companies submitted data as far back as the early 1980's. The key findings of the study are as follows.

- A trend in declining use per residential natural gas customer of 1 percent annually has been documented[2] back to 1980. This decline rate has accelerated since the year 2000.
  - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
  - The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2 percent annually.
  - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline.
  - The decline in use per customer has accelerated since 2000 in all 9 geographic regions analyzed.
- No appreciable changes in the price elasticity of demand were observed post-2000. Price elasticity of demand refers to the percentage change in demand for a good relative to a percentage change in price. Although the elasticity has not changed over time, it should be noted that natural gas is an essential product that provides heat, hot water and cooking. Despite the essential nature of natural gas, consumers have continued to reduce their consumption at a relatively constant rate with respect to changing prices. Therefore, the large price increases post-2000 have resulted in the large consumption declines noted above.

[2] 2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001.

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- This study found a short-run price elasticity of –0.09 and a long-run price elasticity of -0.18. (Long-run elasticity refers to a period of time long enough for consumers to change the capital stock of their energy consuming equipment and the shell efficiency of their homes.)

- These price elasticity estimates are relatively consistent with previous works on this subject.

- The econometric analysis presented in this study predicts a decline of 13.9 percent between 2000 and 2006; the actual decline was 13.1 percent. The decline is attributable to a price effect and the longer-run trend towards tighter homes and more efficient appliances. The price elasticity effect is 7.9 percent - equal to the elasticity estimate of -0.18 times the 44 percent real price increase. The remaining 6.0 percent is explained by the longer-run trend towards tighter homes and more efficient appliances.

- As a general rule of thumb, at the national level we would expect a 10 percent increase in the price of natural gas to result in nearly a 3 percent decline in the average residential use per customer 12 months later – 1 percent attributable to more conservation with existing appliances, 1 percent attributable to the price-induced purchase of more efficient appliances, and 1 percent attributable to the natural turnover of equipment that occurs annually.

Background

Residential natural gas consumption is strongly influenced by three factors: seasonal heating needs; response to price change; and the efficiency changes in appliances and home shells caused by a natural turnover rate to more efficient homes and gas appliances. On a weather-adjusted basis, the price and the long run conservation effects are key determinants of changes in residential natural gas consumption. The price effects can be further decomposed into short-term and long-term effects. Short term effects are decisions made by consumers with the current capital stock. Residential customers "turning down the thermostat" would be considered a short term effect. Long term effects are distinguished from short term effects by the inclusion of the decision to purchase more efficient energy consuming appliances and prematurely retiring less efficient ones. The price elasticity in the long-run is the sum of (1) the short-run demand and (2) the additional changes that occur to quantity demanded one year later because of natural gas price effects on the efficiency of the appliance capital stock and on the shell efficiency of homes[3]. While the separate efficiency and conservation effects due to

[3] It should be noted that if natural gas prices decrease, consumers will not replace recently purchased efficient equipment with less efficient equipment. So there maybe asymmetry with respect to the impact of natural gas prices on appliance and shell efficiency. The efficiency gains in appliance equipment that have occurred in the last several years will not disappear if natural gas prices go down. However, declining prices may lead consumers turning up thermostats to increase comfort levels (in the short-run). In the very long-run, a decline in prices could lead to an increase in burner tips per customer.

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Table ES1 disaggregates the national winter season weather normal use per residential customer across the nine US Census Regions and for the US. The decline in weather normal use per customer has occurred across all US Census regions. The decline ranges from 5.7 dekatherms per customer for the West South Central region to 10.9 dekatherms for the East North Central region. The percentage decline in use per customer ranged from 9.2 percent for the Middle Atlantic Region to 14.8 percent for the Pacific Region.

Table ES1
Annual Winter Season Weather Normal
Natural Gas Use per Residential Customer,
By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Price Elasticity and "Natural" Conservation Estimates

This study found that neither a practical nor statistically significant change in the price elasticity of residential natural gas consumption occurred in the post year 2000 period. The price elasticity of residential natural gas demand appears to have remained relatively constant since the 1990s. This implies the large percentage price increase since 2000 accounted for the decline in natural gas use, rather than an increased sensitivity or greater response by households to a given price change. The study also found that independent of natural gas price increases, the naturally occurring decline due to the technology driven gain in appliance and home thermal shell efficiency, as well as changes in conservation attitudes was 1 percent per year.

Table ES2 illustrates that for the sample of companies in the study, the short run price elasticity of demand averaged -0.09, while the long run estimated averaged -0.18. Therefore, given a 10 percent increase in the price of natural gas, consumption would decline 2.8 percent; 1.8 percent for price response, added to 1.0 percent decline due to the normal turnover of appliances and other "natural" conservation measures. There is very little regional variation in the total impact of a 10 percent increase in real prices on use per

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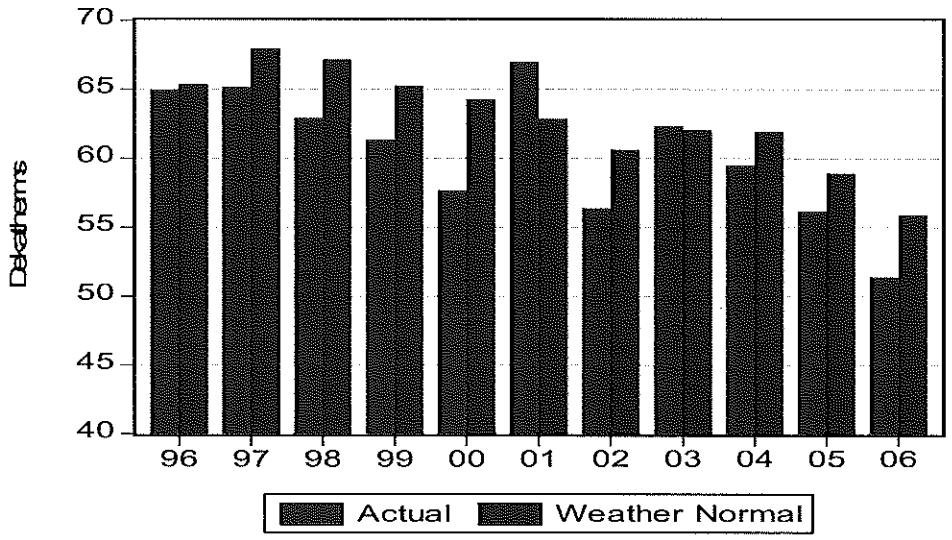
appliance and housing shell turnover are difficult to disentangle in the current sample, they do appear to be discernable from the long term price effects.

To address these issues, AGA commissioned a study to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. Other objectives of this study were: to obtain updated elasticity estimates for all nine US Census Regions and for the US; to test for an increase in the price elasticity of demand for natural gas since the year 2000; and to estimate a natural rate of decline in use per customer due to technology-induced gains in appliance and shell efficiency and a change in conservation attitudes that would occur even in an environment of constant real natural gas prices.

Decline in Use per Customer

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has accelerated. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent nationally between 2000 and 2006 for the sample of companies analyzed in this report. Figure ES1 below shows the winter season use per customer in actual and weather normal dekatherms from 1996-2006 using the data collected by AGA.[4] It is clear that actual and weather normalized use per customer has been declining since 1997 and this decline has accelerated since 2004.

Figure ES1
US Annual Winter Use per Customer



[4] The data was collected from 46 Local Distribution Companies (LDCs) in 29 states, representing 28 percent of all residential customers. An LDC is a gas utility that serves a specific rate jurisdiction. Some of the companies in this sample have multiple jurisdictions in their corporate structure. The winter season for this report is defined as the sum of the monthly consumption between October and March.

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Overall decline in Winter Gas Use per Customer	=	*Price Effect Elasticity with Price Increase*	+	*Conservation and Turnover to More Efficient Appliances*
13.9%	=	0.18 *x* 44%	+	6 *x* 1.0%
	=	7.9%	+	6.0%

In the expression above, the left hand term is the overall predicted decline of winter gas use per customer, the first term on the right hand side is the price effect reflecting the elasticity estimate multiplied by the price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

The results from analyzing the AGA sample data lead to a general rule of thumb. This rule does not apply to all companies in all situations, but the general rule with its caveats provides valuable insight to the underlying processes governing consumer behavior. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across both the LDCs and Census regions. Twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer on a national level. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by replacing still functional appliances with more efficient units, and about a 1 percent drop in gas usage per customer due to the natural turnover of old gas appliances to the more efficient gas appliances that are available in the market each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

Other factors that impacts residential energy use are the many programs that encourage consumers to save energy. These include:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for the purchase of efficient appliances and housing shell improvements, and consumer education on the importance of saving energy.
- State and local governments also encourage efficiency through similar programs.
- Many utilities provide rebates, incentives, and assistance to their customers to conserve energy use. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes.[6]

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances

[6] Source: http://liheap.ncat.org/tables/FY2005/05stlvtb.htm

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customer. The impact in all regions was close to the national estimate of 2.8 percent, with the Mountain region being the lowest at 1.9 percent and the South Atlantic region being the highest at 3.7 percent.

The study also found that the elasticity estimates calculated using the sample data were generally consistent with the elasticity estimates found in the energy economics literature.[5]

Table ES2
Summary of National and Regional
Natural Gas Price Elasticity Estimates*

Region	Short-run elasticity	Long-run elasticity**	Annual Time Trend	Total Response to a 10% Price Increase***
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Estimates obtained from the "fixed effects" pooled regression
** Cumulative: includes impacts of short-run elasticities
*** The total response to a 10% price increase is the sum of the long-run elasticity and the annual time trend effect.

Implications

These price elasticity estimates and the natural conservation trends are able to explain the post 2000 winter consumption per household per customer actual experience.

Between 2000 and 2006, real natural gas prices for the sample companies in this study rose 44 percent, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

[5] See Appendix C of the main report for a summary of the elasticity estimates found in the energy economics literature.

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to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in thermal shell efficiency from new construction will result in continued conservation, impacting utility operations. Third, even if future natural gas prices remain constant or even decrease, the appliance and house shell efficiency gains achieved in prior years will not be reversed.

Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from natural gas companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

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Introduction

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has increased. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 for the sample of companies analyzed in this report.

It is important from a budgeting point of view for Local Distribution Companies (LDCs) to understand the cause of this decline. Was it caused by the recent increases in natural gas prices and customer's response to these price increases? Did customers change their behavior in response to these price increases? Have they become more sensitive to natural gas price movements or has the price induced response behavior remained relatively the same over time? Did customers switch to more efficient gas appliances in response to these natural gas price increases? Is it due to technological innovations which lead to increased efficiencies in appliances and thermal shells of homes? These efficiencies are in some sense passive as older appliances are replaced with more efficient models through natural attrition.

To address these issues, the American Gas Association (AGA) funded a study to re-estimate the price elasticity of natural gas demand by residential households using a sample of data that covers the recent period of large natural gas price increases. The main objective of this study was to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. A second purpose of this study was to test for an increase in the price elasticity[7] of demand for natural gas since the year 2000. A third and equally important purpose of this study was to obtain updated elasticity estimates for all nine US Census Regions and for the US as a whole. Finally, the study attempts to estimate a natural rate of decline in use per customer due to technology induced gains in appliance and shell efficiency that would even occur in an environment of constant real natural gas prices.

There are hundreds of studies on the elasticities of natural gas demand. These studies have generated a range of elasticity estimates. If one goes back to the 1970's and even to the 1960s, these estimates vary over a wide range. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to a high of –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates, the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to a high of –3.42 in Beirlein, Dunn and McConnon (1981). See Dahl and Roman (2004) and Dahl, et. al. (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). See Appendix C for a brief literature review of price elasticity estimates.

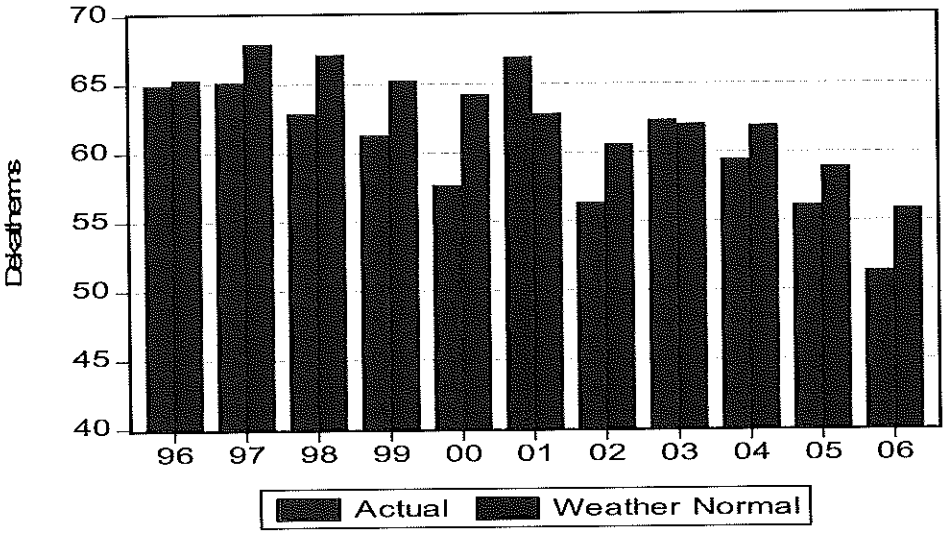
[7] The price elasticity of demand is defined as the ratio of the percent change in quantity demanded of a particular good to the percent change in the price of that good, such as natural gas demand in this study.

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Section 1: Background

Residential natural gas consumption per customer in the US has been declining. Figure 1 below shows the winter season use per consumption actual and weather normal (in dekatherms) from 1996 to 2006 using the data collected from the sample LDCs. The winter season for this report is defined as the sum of the monthly consumption between October and March.

Figure 1
US Annual Winter Use per Customer



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Many of the studies estimated elasticities of natural gas demand with data aggregated at the state and national level and collected by the States; or collected by the Energy Information Administration (EIA). Examples of these are Balestra and Nerlove (1966), Jaskow and Baughman (1976), Berndt and Watkins (1977), and more recently, Maddala, Trost, Li, and Joutz (1997). Other studies use individual micro data to estimate demand elasticities. Examples of these are Hewlett (1977), Barnes, Gillingham and Hagemann (1982), and Green and Gilbert (1983). While the former studies using state and national aggregate data may provide some useful information at the state and national level, and the latter studies may provide good estimates of individual demand elasticities, neither provide adequate estimates at the individual LDC level of aggregation. Most of these studies do not allow for a natural rate of decline in use per customer due to technologically induced efficiency gains in appliances and thermal shells of homes. In addition, there are few, if any, studies that use current data that includes the recent run-up in natural gas prices. This study will fill these gaps in the literature by using high quality data collected and compiled at the individual LDC level and covering the period as recent as March, 2006.

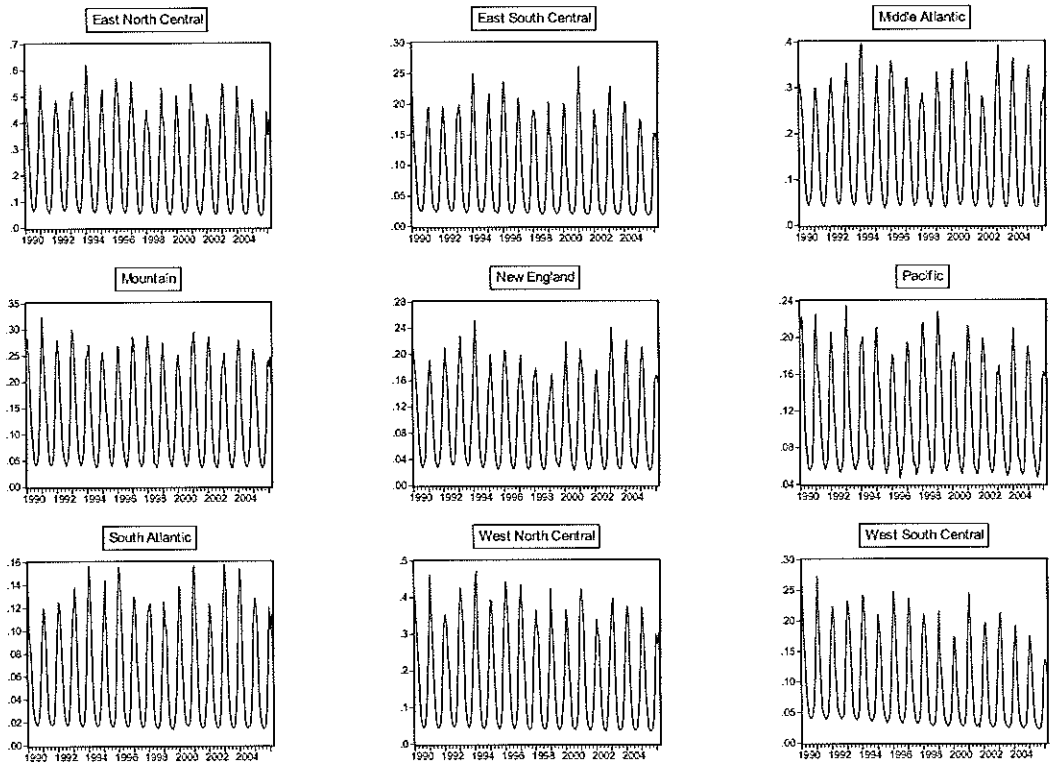
This paper is divided into the following five sections. In Section 1, background information at the regional, as well as the national level, is provided. The information includes residential natural gas consumption, the declining trend of consumption, and price movements. In Section 2, the database constructed from the survey of LDCs is described. Section 3 explains the mathematical equations used to estimate short- and long-run price elasticity of demand. Empirical results of short-run and long-run elasticity and the declining trend in gas usage are presented in Section 4. The report concludes in Section 5 with a summary of the results and policy implications. In addition, there is a list of suggestions for future research. References and technical appendices can be found at the end of the report. The appendices include construction of the weather-normalized series for use per customer, a map of the Census regions, a brief literature review, and a discussion of statistical hypothesis testing.

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customers to trade in old inefficient appliances for newer more efficient ones. The impact on the natural gas industry will be an obvious decrease in revenue accruing to natural gas LDC's.

This study will examine the reasons for this decline in use per customer, with particular emphasis on estimating the short-run and long-run price elasticity of natural gas demand since the year 2000. It will also analyze and measure the rate of decline caused by the natural turnover rate of old inefficient appliances with newer more efficient ones. The trends in the AGA sample are validated from trends in other data. The U.S. Energy Information Administration (EIA) reports aggregate estimates of residential consumption in BCF/day and residential prices in $/MCF on a monthly basis from 1990 to the present. The EIA sample data covers all LDCs in the US. These series are plotted by US Census Region in residential consumption per household per day in Figure 2 and in nominal and real terms in ($2000)/MCF in Figure 3 below. A map of the US Census Regions is shown in Appendix B. These figures provide a comparison with the subsequent figures from the AGA survey database. They demonstrate that the trends and patterns in the survey are consistent with a recognized national source of data even before adjusting for normal weather.

Figure 2
Regional Consumption per Customer per Day
Mcf per Day



Source: U.S. Energy Information Administration

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Table 1: US Annual Winter Use per Residential Customer in Dekatherms				
Year	Actual		Winter Normal	
	Level	Percent Change	Level	Percent Change
1996	64.9		65.3	
1997	65.2	0.5	67.9	4.0
1998	62.9	-3.5	67.1	-1.2
1999	61.3	-2.5	65.2	-2.8
2000	57.7	-5.9	64.3	-1.4
2001	67.0	16.1	62.8	-2.3
2002	56.4	-15.8	60.6	-3.5
2003	62.3	10.5	62.0	2.3
2004	59.5	-4.5	61.9	-0.2
2005	56.2	-5.6	58.9	-4.9
2006	51.4	-8.5	55.9	-5.1
Annual Percent Change 1996-2000		**-1.64**		**-1.48**

As can be seen from Figure 1 and Table 1, there has been a marked decline in weather normal use per customer. The annual percent change from 1996 to 2006 was -1.64 percent and -1.48 percent respectively, for actual and weather normal consumption. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 and by 9.7 percent between 2004 and 2006 for the sample of companies analyzed in this report.

The phenomenon of declining weather normal use per customer is not new[8]. Some even feel it started on February 1, 1977 when then President Jimmy Carter, after only two weeks in office, said in his now famous fireside chat:

"*All of us must learn to waste less energy. Simply by keeping our thermostats, for instance, at 65 degrees in the daytime and 55 degrees at night we could save half the current shortage of natural gas.*"

In the years since, the first President Bush established the first National Energy Strategy in June of 1989, and the government has imposed efficiency standards, subsidized technological improvements in both shell and appliance efficiency, and generally encouraged its citizenry to conserve on energy. Efficiency improvements are sure to continue, and if natural gas prices stay high, it will most certainly encourage natural gas

[8] Between 1978 and 1982, energy consumption per household actually decreased by 26%. See EIA's Annual Energy Review, URL http://www.eia.doe.gov/emeu/aer/ep/ep_frame.html.

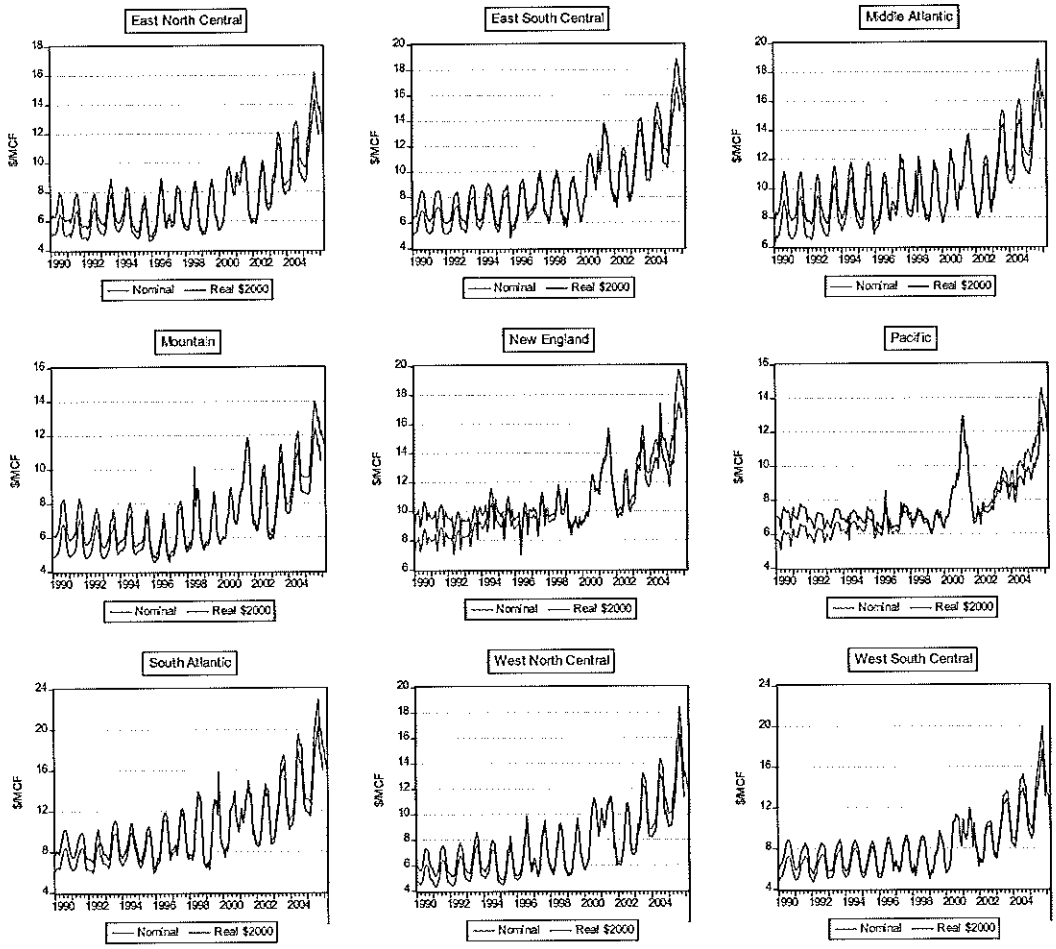
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While income is important in any economic analysis of demand, income was not included in our final model for several reasons. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should have been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation. Third, our findings are similar to surveys of natural gas demand by Bohi (1981), Dahl (1993, and personal discussions about preliminary results regarding an update to Dahl's previous study). In a number of papers, Bohi dismisses the large income elasticities from some static cross section estimates and concluded that income is not found to be an important variable in natural gas demand. Dahl found that income effects in residential demand models are consistently small in both aggregate and disaggregate data. Both authors suggest that representing the income effect in residential is problematic and sensitive to the particular study.

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Regional consumption per customer appears to decline for every region for most of the period and particularly after 2000. This has occurred while residential natural gas prices have more than doubled over the same period.

Figure 3
Nominal and Real ($2000) Delivered Natural Gas Prices

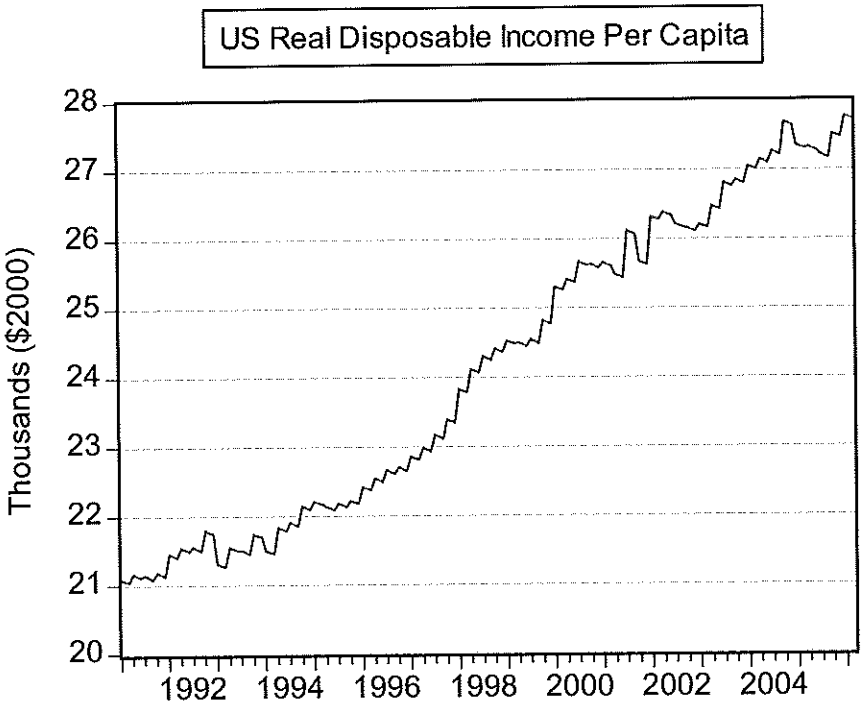


Source: U.S. Energy Information Administration

Residential natural gas prices were fairly stable between 1990 and 1997 during the so-called "gas bubble" period. However, they have been increasing, particularly since 2000 due to a variety of factors, including increasing oil prices (Villar and Joutz, October 2006). Nominal prices have risen faster in some regions than in others; the spread in nominal terms has been between $12/MCF to almost $20/MCF. The real price has more than doubled to over $12/MCF. Natural gas prices have risen about 35 percent to 40 percent faster than the general U.S. price level since 1990. Figure 3 shows the monthly residential natural gas prices per MCF according to the EIA. Figure 4 shows U.S. real disposable income per capita has risen about 33 percent from $21,000 to $28,000 today.

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Figure 4



Source: Bureau of Economic Analysis, U.S. Department of Commerce

Table 2 shows the cumulative decline of winter weather normal use per customer between 2000 and 2006 for the sample of the LDCs. The focus of Table 2 is the post 2000 period. The intent is to capture the effects of the large increases in natural gas prices and (possible) conservation activities by consumers.[9] The fall, on average, is greater than two per cent per year for six of the nine Census Regions and for the U.S.

[9] The pre-2000 period will be addressed in the statistical modeling sections.

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Section 2: Data

Sixteen AGA member companies provided data for this study. The companies supplied monthly data on residential consumption, average prices, number of customers, heating-degree data, and economic data. Most companies were able to provide a time series of data starting in 1992 and in some cases even into the 1980s. Three companies were unable to contribute data prior to 1999 for accounting or reorganization reasons. The remaining fifteen corporations comprise 46 local distribution companies. This represents more than 16 million customers and 28 percent of all residential customers nationwide.

Micro data on individual consumers is best suited for obtaining estimates of price elasticities. In rate case decisions and in internal LDC corporate strategy decisions however, the most relevant and useful piece of information is how the external forces that bombard it now impact the LDC. These external forces can vary from announcements by Presidents, changes in a competitors pricing, new gas appliance technologies, economic recessions, and gas price increases imposed by fuel surcharges. Since it is the impact of these forces on actual individual LDC's that is relevant, current data on consumption and prices collected by each individual LDC and aggregated at the individual LDC level is best suited to measure the impact of these external forces on a LDC in the current time period.

But data on a single LDC is often not enough information. The problem with using current data from only one LDC is that the number of observations will be quite small, and statistical reliability will be compromised. Instead of tens of thousands of observations on individual consumers, one may be left with 50 or 60 observations for any given LDC during the important winter season months. From a statistical reliability point of view then, it is important to obtain on many different individual LDCs, data that are collected by each individual LDC rather than using survey data collected by government agencies such as the EIA.

In this study, the breadth and depth of the data collected by the AGA has not to our knowledge been done before. The breadth of the data spans the entire US, covering 46 different LDCs. The depth of the data covers almost a decade or more for most of the companies. Therefore, this is a data set that is uniquely suited for the analysis of residential natural gas consumption in the US.

The number of LDCs in each of the nine Census Regions and the percent of total customers the sample covers for each Region is given in Table 3 below.

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Table 2
Annual Winter Season Weather Normal Natural Gas Use per Residential Customer, By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Table 2 shows the overall decline between 2000 and 2006 for the AGA sample of LDCs. As shown in Table 2, the decline in weather normal use per customer for the national sample is from 64.3 dekatherms in 2000 to 55.9 dekatherms per household in 2006. This represents a cumulative decline of 13.1 percent or an average decline of 2.2 percent per year. The decline since 2004 is even more dramatic, going from 61.9 dekatherms per household in 2004 to 55.9 dekatherms in 2006, nearly a 6 percent decline per year. As shown in this table, every region in the US experienced a decline in use per residential customer.

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where Y_t is use per household of weather normalized Natural gas at time t, X_{t-1} is the real (base = \$2000) price of natural gas at time t - 1, Z_t is real (base = \$2000) household income at time t, K_t is capital stock with a given efficiency E_t at time t, T_t is a annual time trend to capture technological improvements in the efficiency of the capital stock, and ε_t is a random error term.

We use the real price lagged one period to capture the short-run response to a price change since the current price is not known until the gas bill arrives in the next billing period. Hence, a household's price-induced consumption adjustment during this period is based on last period's real gas price.

If equation (1) is in natural logarithms for Y_t, X_{t-1} and Z_t, the coefficient β_1 can be interpreted at the short-run price elasticity of natural gas demand. It measures the responsiveness of natural gas demand at time t to a change in natural gas price at time t-1 for a fixed capital stock of natural gas appliances K_t. In order to derive the long-run price elasticity of natural gas demand, we need to substitute equations (2) and (3) into equation (1) to get

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_3 Z_t + \beta_4 T_t + \varepsilon_t \qquad (4)$$

If all variables except the time trend are in logarithms, then the coefficient on X_{t-1} is an estimate of the short-run price elasticity, the sum of the coefficients on all price variables is an estimate of the long-run price elasticity, and a negative coefficient (β_4) on the annual time trend is the decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment. Although the length of the lag (t-12) on price in equation (2) to capture the capital stock adjustment process is somewhat arbitrary in this formulation, one can put other restrictions on the shape and length of the price and lagged price coefficients by using models such as the Koyck (1954) or Almon (1965) lag.

The coefficient β_1 in equation (4) gives the short-run price elasticity of natural gas demand. In equation (4) the coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. The sum of the coefficients $\beta_1 + \beta_2$ represents the long-run elasticity of natural gas demand. The coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the natural adoption of newer and more efficient capital equipment.

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Section 3: Approaches to Estimating Short- and Long-run Price Elasticity of Demand

Economists often distinguish between a short-run response and long-run response when referring to how a household changes its natural gas usage when faced with price and income changes. The short-run response is defined as a household's natural gas demand response to natural gas price and income changes given their current capital stock of natural gas-using appliances and shell efficiency of the house. The long-run response is defined as a household's response to natural gas prices changes and income changes after the household has had time to change their stock of gas using appliances and house shell efficiency.

The idea behind the short-run and long-run responses to price changes is that when natural gas prices change, a household's short-run response is to alter the intensity with which they use their current stock of natural gas-using appliances. The long-run response to a change in natural gas prices is to alter the number and efficiency of natural gas using appliances, while at the same time changing the shell efficiency of the house.

A household's percentage change in natural gas demand per one percent change in natural gas price is called the price elasticity of natural gas demand. When this percentage change is computed for a household with a given stock of natural gas-using appliances and house shell efficiency, it is termed the short-run price elasticity of natural gas demand for that household. When this percentage change is computed over a time period long enough to allow a household to change it's stock and efficiencies of house and natural gas using appliances, it is termed the long-run price elasticity of natural gas demand for that household. A similar definition is given to short-run and long-run income elasticities of natural gas demand. If the natural gas demand equation is specified in logarithmic form, the price and income coefficients in a regression equation can be interpreted as the price and income elasticities.

A Dynamic Model of Capital Stock Choice and Natural Gas Demand

For a typical household, natural gas is demanded not for its own sake but for use in furnaces, appliances and the like. The household's accumulated energy saving "capital stock" is determined by income, habits, and past prices of fuels. Consequently, in any period, the household's demand for natural gas is a function of the current price, which influences how intensively the stock of equipment is used, and past prices, which influences the size and composition of that stock. A very simple structural model (Fisher and Kaysen, 1962) of these effects for a given household might be

Demand: $$Y_t = \alpha + \beta_1 X_{t-1} + \lambda Z_t + \delta(K_t + E_t) + \varepsilon_t \quad (1)$$

Equipment: $$K_t = \gamma_1 X_{t-i2} + \gamma_2 Z_t \quad (2)$$

Efficiency: $$E_t = \gamma_3 T_t, \quad (3)$$

i = 1,2,3,…..,N (N = 9, Census Regions)

t = 1,2,3,…..T (Time Periods)

The implicit assumption in the fixed effects model is that we retain the i subscript on α but remove the subscript on the β's. The implicit assumption if we run separate regressions for each cross section is that the i subscript is retained on both α and all the β's.

A shrinkage estimator sometimes suggested is the Stein rule estimator defined by:

$$\tilde{\beta}_i = (1 - \frac{c}{F})\hat{\beta}_i + (\frac{c}{F})\hat{\beta}_p, \tag{5}$$

where $\tilde{\beta}_i$ is the shrinkage estimator, $\hat{\beta}_i$ is the separate ordinary least square (OLS) estimate from each time series, $\hat{\beta}_p$ is the fixed effects pooled estimator. The F is the F-test statistic used to test the null hypothesis that all the β's are equal across each cross-section. The constant c is given by

$$c = \frac{(N-1)K - 2}{NT - NK + 2}, \tag{6}$$

and K = 3 and N = 9 in equation 4b.

We will present the shrinkage estimates for the nine Census Regions below when we discuss the regional results.

National Results

We estimated equations (4a) and (4b) for each of the LDCs using OLS on monthly data for the winter season months[11] of October to March. These results are given in the last column of Tables 4 and 5. The average of these individual LDC estimates indicates that the short-run price elasticity of natural gas demand is –0.11, the short-run price elasticity shift in post 2000 is positive but for all practical purposes is zero, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.20, and the natural annual rate of decline[12] in use per customer due to the adoption of new gas appliance capital equipment is 0.8 percent per year.

[11] Although the dependent variables used to estimate the model are only for the months of October to March, the lagged independent real price variables represent actual lagged calendar month real prices. Hence, for the observation on weather normal use per household in October, the lagged real price (t-1) will be the September real price. Similarly, the lagged real price variable (t-12) for an October observation will be the real price of natural gas in October of the previous calendar year.

[12] If the coefficient on the time trend (T) in equation 4a and 4b is negative, it means there is an annual decline in natural gas weather normal use per customer. The percent decline will be equal to the coefficient on the time trend multiplied by 100%. For example, in Table 4 for the National sample, we see the coefficient on the

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has become more elastic since the year 2000. The coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment.

The sum of the coefficients $\beta_1 + \delta_{2000}$ in equation (4a) gives the short-run price elasticity of natural gas demand in the post-2000 period, the sum of the coefficients $\beta_1 + \delta_{2000} + \beta_2$ represents the long-run elasticity of natural gas demand in the post-2000 period, and the coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2.

The interpretation of the coefficients for equation (4b) is similar, except in equation (4b) the slope shift coefficient δ_{2000} for the short-run elasticity is constrained to zero.

Shrinkage Estimators

With a panel data set such at the one used in this study, there is always the question of whether to pool the data and obtain a single estimate of the parameters from the whole sample, or to estimate the equations separately for each cross-section. The implicit assumption in the fixed effects model is that the intercepts are different for each cross-section, but the slope coefficients are the same for all cross sections. This may not be a tenable assumption. Indeed, in practice the constancy of slope coefficients across different cross-section units is often rejected. This implies that the equations should be estimated separately for each cross-section rather than obtaining an overall pooled estimate.

The problem with the two usual estimation methods of either pooling the data or obtaining separate estimates for each cross section is that both are based on extreme assumptions. If the data are pooled as in the fixed effects model, it is assumed the coefficients are all the same. If separate estimates are obtained for each cross section, it is assumed that the coefficients are all different for each cross section. The truth probably lies somewhere in-between. The coefficients are not exactly the same, but there is some similarity between them.

One way to allow for some similarity among the slope coefficients without constraining them to be exactly the same is to assume the coefficients all come from a joint distribution with a common mean and non-zero covariance matrix. This suggests that the resulting coefficient estimates should be a weighted average of the overall pooled estimate and the separate time series estimates based on each cross section. Thus, each cross-section estimate is "shrunk" towards the overall pooled estimate.

For example, consider the model given by equation (4b) and using aggregate data on the nine census Regions to estimate the coefficients. This model is:

$$Y_{it} = \alpha_i + \beta_{i1}X_{i,t-1} + \beta_{i2}X_{i,t-12} + \beta_{i4}T_{it} + \varepsilon_{it},$$

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Section 4: Empirical Results Using the AGA Sample of LDCs

The AGA study is interested in answering the following five questions:

(a) What are the changes in natural gas use per residential customer on a weather normalized basis since the year 2000?
(b) What is the short-run price elasticity of demand for residential natural gas customers?
(c) What is the long-run price elasticity of demand for residential natural gas customers?
(d) Has elasticity of natural gas demand changed since 2000?
(e) What is the annual reduction in natural gas usage per customer due to the natural replacement of old inefficient natural gas appliances with more energy efficient appliances; and the building of new homes with greater shell efficiencies compared to existing homes?

To answer these questions we estimated two variants of equations[10] (1) to (3). The first variant assumes the short-run price elasticity has a structural shift in the year 2000 and the second model assumes there is no shift in the short-run price elasticity in the year 2000 and beyond. These two equations are given below as (4a) and (4b), respectively:

$$Y_t = \alpha + \beta_1 X_{t-1} + \delta_{2000} X_{t-1} * D2000 + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4a)$$

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \quad (4b)$$

where all variables except the time trend are in natural logarithms and D2000 is a 0,1 indicator variable, equal to 0 if the time period is pre year 2000, and equal to 1 if the time period is the year 2000 or greater. The dependent variable Y_t in equations (4a) and (4b) is daily natural gas use per customer in month t.

In equation (4a), the coefficient δ_{2000} is a shift coefficient on the price elasticity given by β_1. The interpretation of δ_{2000} is that β_1 represents the price elasticity of natural gas demand for the period prior to the year 2000, and $\beta_1 + \delta_{2000}$ gives the price elasticity of natural gas demand for the year 2000 and beyond. So a negative δ_{2000} in equation (4a) would indicate that demand

[10] We omitted the income variable Z_t for the reasons outlined the Background Section of the paper. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should has been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation.

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We also estimated equations (4a) and (4b) in a pooled regression where each LDC is given company specific intercepts for each of the six winter months in the sample, but all the slope coefficients were assumed to be the same across all LDCs. These estimates are shown in column two of Tables 4 and 5 below. Based on these estimates, we see the short-run price elasticity is –0.09, there is neither a practical nor a statistically significant[13] shift in the elasticity in post 2000, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.18, and the natural annual rate of decline due to the adoption of new capital equipment is 1.0 percent per year in Table 5. Note the results did not indicate a change in price elasticity in the post-2000 time period in Table 4.

Although we did not obtain Iterative Bayes shrinkage estimates for each individual LDC, based on our experience we expect the average of these shrinkage estimates to fall between the pooled with LDC dummy results and the average of the individual OLS LDC regression results. We conclude therefore, that the short-run price elasticity of natural gas for the national sample lies between –0.09 and –0.10, the long-run price elasticity is between –0.18 and -0.20, and the natural annual rate of decline due to the adoption of new gas appliance capital equipment is between 0.7 percent and 1.0 percent per year. This natural annual rate of decline is consistent with a finding by an earlier AGA report on the decline in weather adjusted gas use per customer. See the AGA report "2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001".

From Table 5 we see the total annual percent decline in use per household one year after a ten percent price increase[14] is between 2.7 percent and 2.8 percent.

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time trend variable is –0.011 for the pooled with LDC dummy variables model. This means there is a 0.011 x 100% = 1.1% annual decline in natural gas weather normal use per customer.

[13] We base this conclusion on the statistical significance of the coefficient on the variable "Ln($Price_{t-1}$)*D2000" in Table 4. See Appendix D for a discussion of the meaning of the term "statistical significance" in statistical hypothesis testing.

[14] Since both the dependent and independent variables are in natural logarithms in equations (4a) and (4b), the coefficients on the two price variables are price elasticities, which give the percent decline in use per customer quantity demanded per one percent increase in price. Similarly, a negative coefficient on the time trend gives the proportionate decline in use per customer per one-year increase in time. To get the percent decline in use per customer one year after a 10 percent increase in price, we have:

$$\text{percent decline} = 10*\text{coefficient on } P_{t-1} + 10*\text{coefficient } P_{t-12} + 100*\text{coefficient on time trend.}$$

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Table 4
National Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-6.46)	-0.10
$Ln(Price_{t-1})$*D2000	0.0036 (0.97)	-0.0003
$Ln(Price_{t-12})$	-0.09 (-5.93)	-0.09
Annual Time Trend	-0.011 (-9.47)	-0.008
$Rbar^2$	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.906	
Number of Observations	3023	41

Table 5
National Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-6.44)	-0.10
$Ln(Price_{t-12})$	-0.09 (-5.92)	-0.10
Annual Time Trend	-0.010 (-12.25)	-0.007
$Rbar^2$	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.908	
Number of Observations	3023	41

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East South Central Region

The regression output for the ESC Region is given in Tables 7A and 7B. In Table 7A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 7B, the short-run elasticity is -0.06 when computed from the average of the individual LDC results and for all practical purposes is zero in the pooled regression. The long-run elasticity is between –0.01 and –0.12. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 2.0 percent. From Table 7B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.0 percent and 2.1 percent, which is slightly lower than the annual percent decline in the national sample.

Table 7A
ESC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.007 (-0.12)	-0.08
$Ln(Price_{t-1})$*D2000	0.0169 (1.09)	0.02
$Ln(Price_{t-12})$	-0.03 (-0.47)	-0.06
Annual Time Trend	-0.023 (-4.92)	-0.016
$Rbar^2$	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.167	
Schwarz Criterion	-0.835	
Number of Observations	227	3

Table 7B
ESC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	0.012 (0.23)	-0.06
$Ln(Price_{t-12})$	-0.026 (-0.44)	-0.06
Annual Time Trend	-0.020 (-5.33)	-0.012
$Rbar^2$	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.170	
Schwarz Criterion	-0.853	
Number of Observations	227	3

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East North Central Region

The regression output for the ENC Region is given in Tables 6A and 6B. In Table 6A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 6B, the short-run elasticity is between -0.08 and –0.12, and is statistically significantly different from zero in the pooled model. The long-run elasticity is between –0.22 and –0.27. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 1.0 percent. From Table 6B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.8 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 6A
ENC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-3.02)	-0.12
$Ln(Price_{t-1})*D2000$	0.005 (0.51)	-0.006
$Ln(Price_{t-12})$	-0.14 (-3.63)	-0.16
Annual Time Trend	-0.011 (-3.92)	0.0013
$Rbar^2$	0.99	
Std. Error of Regression	0.064	
Mean of the Dependent Variable	1.319	
AIC	-2.569	
Schwarz Criterion	-2.200	
Number of Observations	195	3

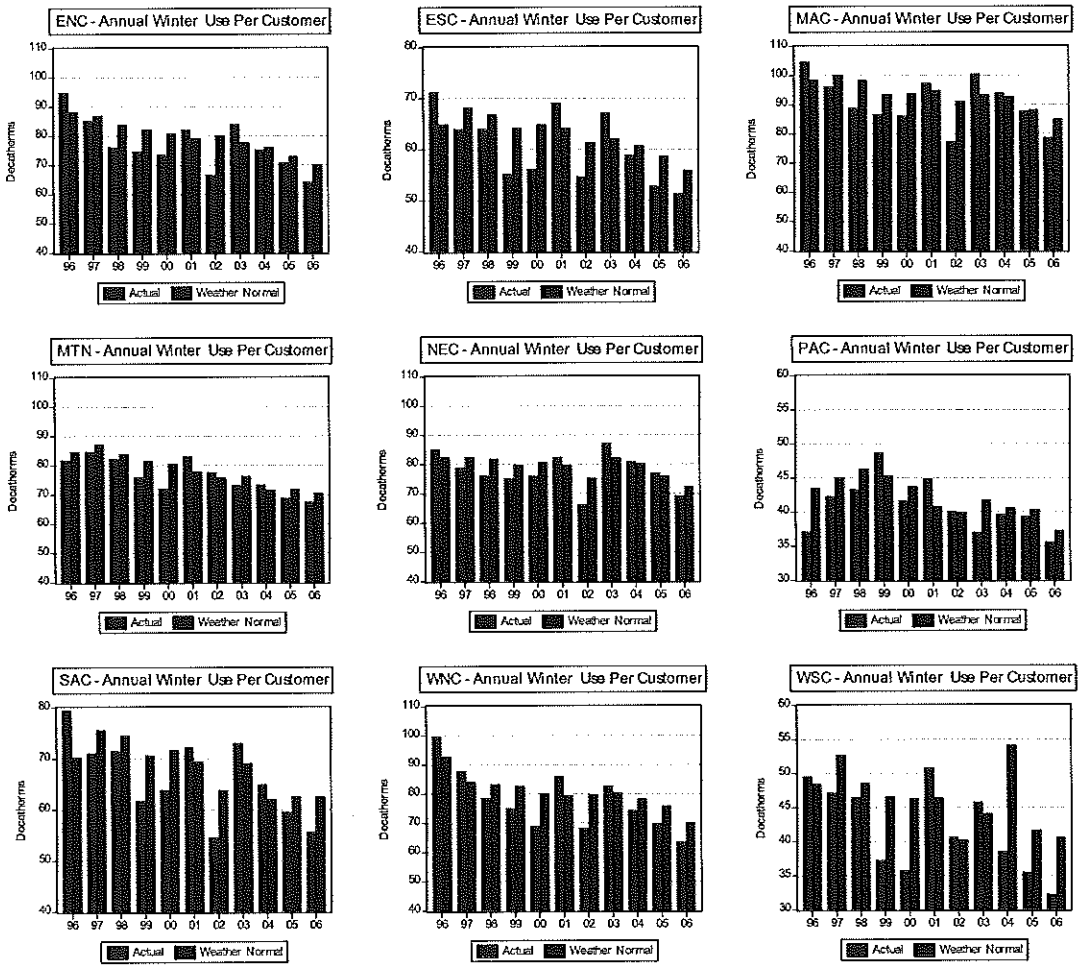
Table 6B
ENC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.08 (-3.02)	-0.12
$Ln(Price_{t-12})$	-0.14 (-3.66)	-0.15
Annual Time Trend	-0.010 (-4.57)	-0.001
$Rbar^2$	0.99	
Std. Error of Regression	0.063	
Mean of the Dependent Variable	1.319	
AIC	-2.578	
Schwarz Criterion	-2.225	
Number of Observations	195	3

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Figure 6 shows the actual and normalized winter season consumption for natural gas per customer by U.S. Census region for the AGA sample. Again, there is a decline over much of the sample in all regions.

Figure 6
Regional Annual Winter Use per Customer
(Dth)



Regional OLS Estimates

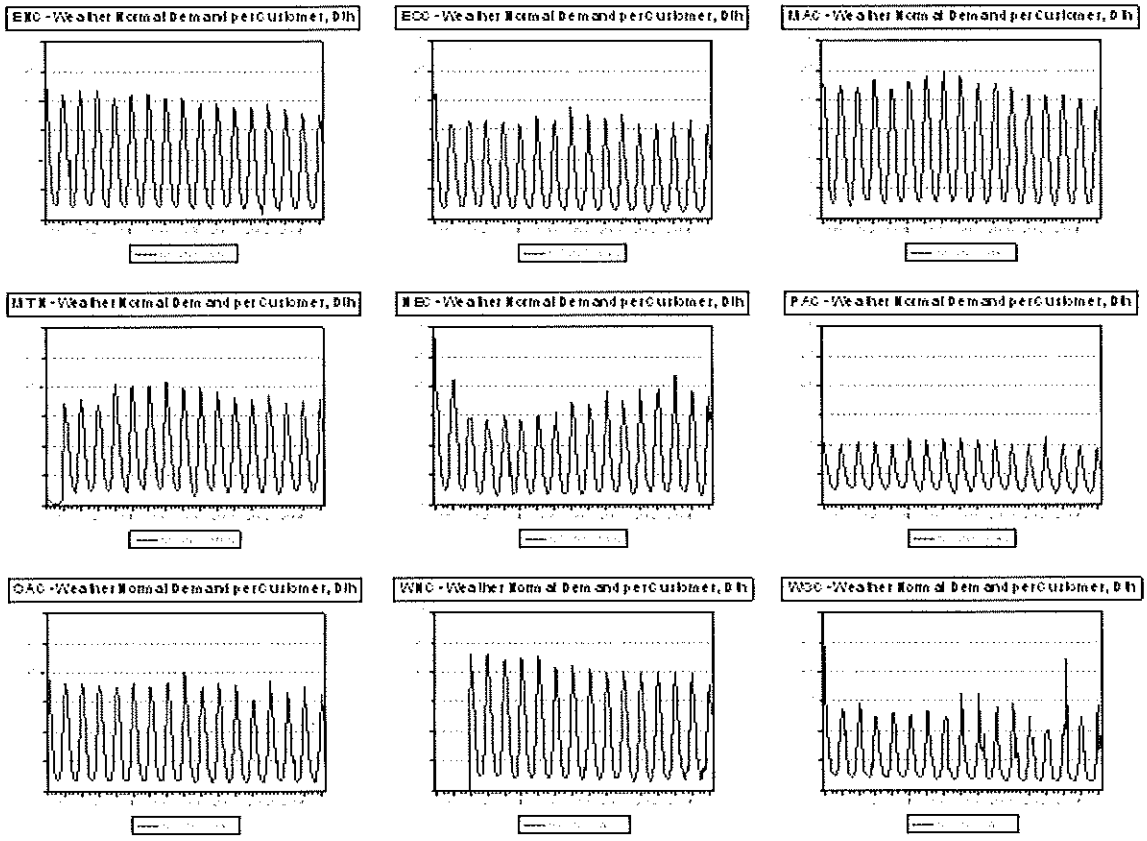
Tables 6A and 6B to Tables 14A and 14B give the estimates of equations (4a) and (4b) for each of the nine census Regions using data on the individual LDCs in each of the respective regions. For the most part, the regional results are similar to the national results, with some differences noted below.

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Regional Results

Figure 5 shows the normalized consumption of natural gas use per household by U.S. Census region for the AGA sample. There appears to be a decline over much of the sample in all nine Census Regions.

Figure 5
Regional Weather Normal Consumption per Customer
(Dth)



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Middle Atlantic Region

The regression output for the MAC Region is given in Tables 8A and 8B. In Table 8A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 8B, the short-run elasticity is -0.13 when computed from the average of the individual LDC results, and is –0.10 in the pooled regression. The long-run elasticity is between –0.18 and –0.20. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 1.3 percent. Table 8B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 3.3 percent, which is close to the annual percent decline in the national sample.

Table 8A
MAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.11 (-2.35)	-0.12
$Ln(Price_{t-1})$*D2000	0.01 (1.21)	0.005
$Ln(Price_{t-12})$	-0.09 (-1.70)	-0.04
Annual Time Trend	-0.015 (-5.21)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.681	
Schwarz Criterion	-1.325	
Number of Observations	465	6

Table 8B
MAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.10 (-2.24)	-0.13
$Ln(Price_{t-12})$	-0.10 (-1.77)	-0.05
Annual Time Trend	-0.013 (-5.80)	-0.007
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.682	
Schwarz Criterion	-1.335	
Number of Observations	465	6

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South Atlantic Region

The regression output for the SAC Region is given in Tables 12A and 12B. In Table 12A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 12B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is -0.12 and statistically significant in the pooled regression. The long-run elasticity is between -0.24 and -0.29. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. Table 12B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 3.4 percent to 3.7 percent, which is higher than the annual percent decline in the national sample.

Table 12A
SAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.115 (-3.09)	-0.10
$Ln(Price_{t-1})$*D2000	-0.002 (-0.15)	-0.005
$Ln(Price_{t-12})$	-0.17 (-4.16)	-0.13
Annual Time Trend	-0.008 (-2.58)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.109	
Mean of the Dependent Variable	1.218	
AIC	-1.509	
Schwarz Criterion	-1.146	
Number of Observations	280	4

Table 12B
SAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.12 (-3.30)	-0.11
$Ln(Price_{t-12})$	-0.17 (-4.18)	-0.13
Annual Time Trend	-0.008 (-3.76)	-0.010
$Rbar^2$	0.97	
Std. Error of Regression	0.108	
Mean of the Dependent Variable	1.218	
AIC	-1.516	
Schwarz Criterion	-1.166	
Number of Observations	280	4

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Pacific Region

The regression output for the PAC Region is given in Tables 11A and 11B. In Table 11A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although from a practical point of view this decline is small with an impact of only 0.02. According to equation (4b) in Table 11B, the short-run elasticity is -0.07 when computed from the average of the individual LDC results and is also –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.12 and –0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. In Table 11B, we see the total annual percent decline in use per customer one year after a ten percent price increase of 2.0 percent, which is lower than the annual percent decline in the national sample.

Table 11A
PAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.04 (-1.29)	-0.03
$Ln(Price_{t-1})$*D2000	-0.02 (-2.13)	-0.02
$Ln(Price_{t-12})$	-0.05 (-1.66)	-0.07
Annual Time Trend	-0.005 (-1.96)	-0.004
$Rbar^2$	0.98	
Std. Error of Regression	0.072	
Mean of the Dependent Variable	0.910	
AIC	-2.314	
Schwarz Criterion	-1.929	
Number of Observations	258	4

Table 11B
PAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.07 (-2.61)	-0.07
$Ln(Price_{t-12})$	-0.05 (-1.83)	-0.08
Annual Time Trend	-0.008 (-3.87)	-0.005
$Rbar^2$	0.98	
Std. Error of Regression	0.073	
Mean of the Dependent Variable	0.910	
AIC	-2.302	
Schwarz Criterion	-1.931	
Number of Observations	258	4

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New England Region

The regression output for the NEC Region is given in Tables 10A and 10B. In Table 10A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although in this case it is a shift that lowers the short-run price elasticity and is not practically significant with only 0.015 decrease. According to equation (4b) in Table 10B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is also –0.08 and statistically significant in the pooled regression. The long-run elasticity is between –0.25 and –0.28. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer demand of 0.4 percent. Table 10B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.0 percent, which is close to the annual percent decline in the national sample.

Table 10A
NEC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-3.34)	-0.09
$Ln(Price_{t-1})$*D2000	0.015 (2.44)	0.01
$Ln(Price_{t-12})$	-0.17 (-5.06)	-0.20
Annual Time Trend	-0.008 (-4.24)	-0.005
$Rbar^2$	0.97	
Std. Error of Regression	0.096	
Mean of the Dependent Variable	1.307	
AIC	-1.767	
Schwarz Criterion	-1.413	
Number of Observations	660	8

Table 10B
NEC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.08 (-2.86)	-0.08
$Ln(Price_{t-12})$	-0.17 (-5.00)	-0.20
Annual Time Trend	-0.004 (-3.73)	-0.002
$Rbar^2$	0.97	
Std. Error of Regression	0.097	
Mean of the Dependent Variable	1.307	
AIC	-1.760	
Schwarz Criterion	-1.412	
Number of Observations	660	8

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Mountain Region

The regression output for the MTN Region is given in Tables 9A and 9B. In Table 9A, we estimate shift of –0.035 in the short-run elasticity in post 2000 and beyond. According to equation (4b) in Table 9B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.10 and –0.19. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 0.9 percent. In Table 9B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 1.9 percent and 2.8 percent, which in the pooled regression (1.9 percent) is slightly lower than the annual percent decline in the national sample.

Table 9A
MTN Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.014 (-0.52)	-0.08
$Ln(Price_{t-1})$*D2000	-0.035 (-4.19)	-0.02
$Ln(Price_{t-12})$	-0.018 (-0.75)	-0.07
Annual Time Trend	-0.004 (-2.47)	-0.007
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.700	
Schwarz Criterion	-2.353	
Number of Observations	298	4

Table 9B
MTN Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.07 (-2.73)	-0.11
$Ln(Price_{t-12})$	-0.03 (-1.33)	-0.08
Annual Time Trend	-0.009 (-6.22)	-0.009
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.644	
Schwarz Criterion	-2.309	
Number of Observations	298	4

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West North Central Region

The regression output for the WNC Region is given in Tables 13A and 13B. In Table 13B, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although it is a shift that lowers the short-run price elasticity by only–0.014 and from a practical point of view is not significant. According to equation (4b) in Table 13B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is –0.09 and statistically significant in the pooled regression. The long-run elasticity is between -0.13 and -0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.1 percent. In Table 13B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 2.6 percent, which is close to the annual percent decline in the national sample.

Table 13A
WNC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.10 (-5.19)	-0.09
$Ln(Price_{t-1})$*D2000	0.014 (1.98)	0.01
$Ln(Price_{t-12})$	-0.06 (-2.62)	-0.05
Annual Time Trend	-0.014 (-5.48)	-0.014
$Rbar^2$	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.141	
Schwarz Criterion	-2.765	
Number of Observations	190	3

Table 13B
WNC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-4.78)	-0.08
$Ln(Price_{t-12})$	-0.06 (-2.69)	-0.05
Annual Time Trend	-0.011 (-5.35)	-0.012
$Rbar^2$	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.129	
Schwarz Criterion	-2.770	
Number of Observations	190	3

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West South Central Region

The regression output for the WSC Region is given in Tables 14A and 14B. In Table 14A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 14B, the short-run elasticity is -0.14 when computed from the average of the individual LDC results and is –0.13 and statistically significant in the pooled regression. The long-run elasticity is -0.16 in both the pooled regression and when computed as the average of the individual LDC OLS estimates. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.6 percent. In Table 14B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 14A
WSC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.12 (-1.71)	-0.13
$Ln(Price_{t-1})$*D2000	-0.008 (-0.48)	-0.009
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.015 (-2.52)	-0.01
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.318	
Schwarz Criterion	0.048	
Number of Observations	450	6

Table 14B
WSC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.13 (-1.87)	-0.14
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.016 (-3.79)	-0.013
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.322	
Schwarz Criterion	0.034	
Number of Observations	450	6

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East North Central Region

Table 16 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the ENC Region is -0.047 and -0.122, and the annual time trend shows a declining annual rate of 1.7 percent.

Table 16

ENC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	Estimate	t-stat	
Ln($Price_{t-1}$)	-0.043	-0.349	-0.047
Ln($Price_{t-12}$)	-0.076	-0.544	-0.075
Annual Time Trend	-0.017	-1.530	-0.017
Number of Observations	60		

East South Central Region

Table 17 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for East South Central is -0.030 and -0.085, and the annual time trend shows a declining annual rate of 1.8 percent.

Table 17

ESC – Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.026	-0.180	-0.030
Ln($Price_{t-12}$)	-0.055	-0.337	-0.055
Annual Time Trend	-0.018	-1.270	-0.018
Number of Observations	60		

Shrinkage Estimates

We also estimate equation (4a) and (4b) with a type of shrinkage estimator, time series data on the Nine Census Regions, aggregated over the respective LDCs in each region. We will apply the Stein rule estimator discussed above in the sub-section on Shrinkage Estimators. The advantage of shrinkage estimators is that they allow for some similarity among the slope coefficients without constraining them to be exactly the same as in the case of pooled estimates.

Using aggregate regional data, Table 15 below gives the pooled fixed effects estimates of equation (4b) and the average of the individual regional coefficient estimates. These estimates are similar to the estimates presented in Table 5B based on individual LDC data. Note that in Table 5B the impact of a 10 percent price increase was a 2.8 percent decline in use per customer one year later. Using regional aggregate data we see the impact of a ten percent price increase is a similar 2.9 percent decline in use per customer one year later.

Table 15
Regional Elasticity Model Estimates using aggregate data for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With Regional Dummies	Average of Individual Regions
$Ln(Price_{t-1})$	-0.12 (-3.4)	-0.10
$Ln(Price_{t-12})$	-0.06 (-1.63)	-0.08
Annual Time Trend	-0.011 (-3.72)	-0.011
$Rbar^2$	0.98	
Std. Error of Regression	0.094	
Mean of the Dependent Variable	12.14	
AIC	-1.79	
Schwarz Criterion	-1.34	
Number of Observations	540	9

Tables 16 to 24 below present the Stein Shrinkage coefficient estimates of equation (4b) using aggregate regional data. In this case, the shrinkage results are very close to the individual OLS estimates for each Region since F = 0.86 and c = 0.04 since T=60. Plugging into equation (5) we get:

$$\tilde{\beta}_i = 0.95\hat{\beta}_i + 0.05\hat{\beta}_p, \qquad (7)$$

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Middle Atlantic Region

Table 18 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Middle Atlantic Region is -0.164 and -0.46, and the annual time trend shows a declining annual rate of 0.6 percent.

Table 18

MAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.167	-1.198	-0.164
Ln($Price_{t-12}$)	-0.309	-1.887	-0.296
Annual Time Trend	0.006	0.633	0.006
Number of Observations	60		

Mountain Region

Table 19 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Mountain Region is -0.058 and -0.076, and the annual time trend shows a declining annual rate at of 2.22 percent.

Table 19

MTN - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.055	-0.675	-0.058
Ln($Price_{t-12}$)	0.022	0.263	0.018
Annual Time Trend	-0.022	-2.767	-0.022
Number of Observations	60		

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Section 5: Summary of Results and Policy Implications

This research project was initiated to examine the decline in residential natural gas consumption since 2000 and to determine whether there had been a change in the response by residential consumers to higher (and more volatile) natural gas prices. The data that were collected and analyzed support two important findings and a general rule of thumb. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across the LDCs and Census regions.

First, consumption is strongly influenced by seasonal heating needs, response to price change, and the efficiency changes in appliances and home shell efficiency coupled with conservation behavior by consumers. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they appear to be discernable from the price effects. Table 25 gives a summary of the national and separate regional price and naturally occurring time trend effects found in this study.

Second, we could not find evidence supporting an appreciable change in the short-run price elasticity of natural gas consumption in the post year 2000 period.

Table 25
Summary of National and Regional
Natural Gas Price Estimates[16]

Region	Short-run elasticity	Long-run elasticity*	Annual Time Trend	Total Response to a 10% Price Increase**
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Cumulative: includes impacts of short-run elasticities
** The total response to a 10 percent price increase is the sum of the long-run elasticity and the annual time trend effect.

The results from the price elasticity estimates and the combination of efficiency and conservation estimates are able to explain the post 2000 winter consumption per customer actual experience. Normal winter season natural gas use per household in the US has declined

[16] Estimates obtained from the "fixed effects" pooled regression.

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West South Central Region

Table 24 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West South Central Region is -0.209 and -0.258, and the annual time trend shows a declining annual rate of 1.1 percent.

Table 24

WSC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.214	-1.719	-0.209
Ln($Price_{t-12}$)	-0.049	-0.368	-0.049
Annual Time Trend	-0.011	-0.946	-0.011
Number of Observations	60		

Our overall assessment of the regional models is that individual coefficients vary[15] greatly across the nine regional models and are often insignificant. This is due to the small sample sizes relative to the national sample, multicollinearity between the two lagged prices, and to some extent multicollinearity with the time trend as well. Yet the average impact of a 10 percent price increase on use per household is remarkably stable and negative across all nine Census Regions in the pooled regressions using individual LDC data. This total decline after a 10 percent price increase for the nine Census Regions is roughly centered on the national impact of a 2.8 percent decline in weather normal use per customer; with the Mountain Region having a 1.9 percent impact at the low end of the range and the South Atlantic Region having a 3.7 percent impact at the high end of the range.

[15] There may be differences in shell efficiency and new home construction and LDC sponsored energy conservations programs across regions that would lead to some heterogeneity in coefficient estimates across the nine census regions. We feel the iterative Bayes shrinkage estimator could remove much of the inconsistency between the national and regional coefficient estimates in a follow up study.

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South Atlantic Region

Table 22 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the South Atlantic Region is -0.182 and -0.327, and the annual time trend shows a declining annual rate of 1.9 percent.

Table 22

SAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.185	-1.747	-0.182
Ln($Price_{t-12}$)	0.156	1.371	0.145
Annual Time Trend	-0.019	-1.989	-0.019
Number of Observations	60		

West North Central Region

Table 23 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West North Central Region is -0.088 and -0.120, and the annual time trend shows a declining annual rate of 0.90 percent.

Table 23

WNC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.086	-0.966	-0.088
Ln($Price_{t-12}$)	-0.031	-0.355	-0.032
Annual Time Trend	-0.009	-1.053	-0.009
Number of Observations	60		

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New England Region

Table 20 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the New England Region is -0.074 and -0.364, and the annual time trend shows a declining annual rate of 0.3 percent.

Table 20

NEC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	Estimate	t-stat	
Ln($Price_{t-1}$)	-0.072	-0.537	-0.074
Ln($Price_{t-12}$)	-0.302	-1.767	-0.290
Annual Time Trend	-0.003	-0.384	-0.003
Number of Observations	60		

Pacific Region

Table 21 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Pacific Region is -0.089 and -0.179, and the annual time trend shows a declining annual rate of 1.0 percent.

Table 21

PAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.087	-1.066	-0.089
Ln($Price_{t-12}$)	-0.092	-1.194	-0.090
Annual Time Trend	-0.010	-1.157	-0.010
Number of Observations	60		

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about 13.1 percent between 2000 and 2006. There has been an increase in real natural gas prices of 44 percent for the same time period, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

Overall decline in Winter Gas Use per Customer		*Price Effect Elasticity with Price Increase*		*Conservation and Turnover to More Efficient Appliances*
13.9%	=	$0.18 \times 44\%$	+	$6 \times 1.0\%$
	=	7.9%	+	6.0%

In the expression above, the left hand term is the overall declining rate of winter gas use per customer, the first term on the right hand side is the price effect reflecting elasticity with price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

This proposed rule of thumb suggests that twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by buying more efficient appliances, and a 1 percent drop in gas usage per customer due to the natural turnover to more efficient gas appliances each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

It should be noted that the 1 percent price-induced drop with the current capital stock is what economist refer to as the elasticity of "short-run" demand. This refers to customers "turning down the thermostat". There is a second 1 percent price induce drop in use per customer that occurs one year later due to consumers buying more efficient appliances and increasing the tightness of the home. The price elasticity in the "long-run" is the sum of the short-run demand elasticity and the additional changes that occur to quantity demanded one year later because of natural gas price impacts on consumer choice of appliance and home thermal shell efficiency.

The heightened conservation behavior by consumers is partly due to the many government and utility programs that currently exist to encourage residential consumers to save energy:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for purchase of efficient appliances and shell improvements, and consumer education on the importance of saving energy.

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- State and local governments also encourage efficiency through similar programs
- Many utilities provide rebates, incentives, and assistance to their customers to improve use of energy. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes {Source: http://liheap.ncat.org/tables/FY2005/05stlytb.htm }

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in shell efficiency from new construction will result in continued conservation, regardless of price changes, impacting utility operations. Third, even if future gas prices remain constant or even decrease, the appliance and home shell efficiency gains achieved in prior years will not be reversed.

Suggestions for Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from Natural Gas Companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

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Appendix A: Construction of Weather-Normalized Series for Use per Customer

Step 1. Calculate the ratio of HDDN to HDD (normal heating degree days / actual heating degree days.) this is referred to as the weather normalization factor

Step 2. Construct a proxy for base natural gas consumption per customer for each "year". Calculate the average of July and August for each year.

Step 3. Subtract the base consumption from Actual consumption for the September through June for the next 10 months. Refer to this as "heating" consumption. Example: the average of July and August 1999 will be subtracted from September 1999 through June 2000. Retain the actual values for July and August 1999 in the "heating" consumption variable.

Step 4. Calculate the weather normal consumption per customer series. Multiply the "heating" consumption variable by the weather normalization factor. Intuitively, a very cold winter will have relatively high levels of consumption. The very cold weather means that the denominator in the weather normalization factor is large relative to the normal HDD. Multiplying the large consumption variable times the factor, which is less than one, will bring back or reduce consumption towards the normal "heating" consumption level.

Step 5. Add the base consumption per customer back into the September through June normal heating consumption levels.

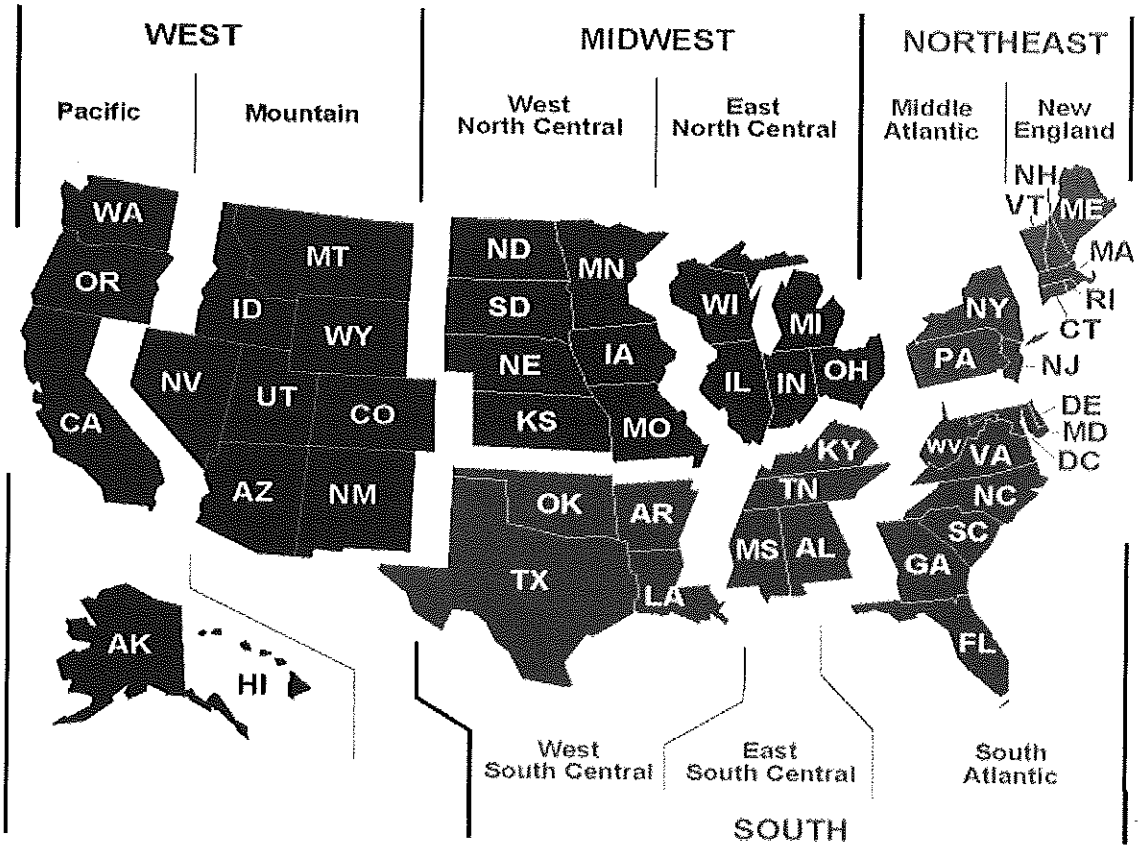
Variable list omitting the region identifiers:

HDD	– Actual Heating Degree Days
HDDN	- Normal Heating Degree Days
CUNG	- Natural Gas Use per Customer per Month
ZSAJQUS	- Days per Month
WNF	- Weather Normalization Factor WNF = HDDN / HDD
Base	- Average of July and August in a year
HCUNG	- "Heating" Natural Gas Use per Customer per Month HCUNG = CUNG – Base
NCUNG	- "Normalized" Natural Gas Use per Customer per Month NCUNG = (HCUNG * WNF) + Base
CUNGW	- Actual Daily Natural Gas Use per Customer per Month CUNGW = CUNG / ZSAJQUS
NCUNGW	- "Normalized" Natural Gas Use per Customer per Month NCUNGW = NCUNG / ZSAJQUS

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Appendix B: U.S. Census Regions

Figure B.1
U.S. Census Region Map



Source: U.S. Dept. of Energy http://www.eia.doe.gov/emeu/cbecs/census_maps.html

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Table B.1
U.S. Census Region Definitions

Division 1	Division 3	Division 5	Division 7	Division 9
New England	**East North Central**	**South Atlantic**	**West South Central**	**Pacific**
Connecticut	Illinois	Delaware	Arkansas	Alaska
Maine	Indiana	District of Columbia	Louisiana	California
Massachusetts	Michigan	Florida	Oklahoma	Hawaii
New Hampshire	Ohio	Georgia	Texas	Oregon
Rhode Island	Wisconsin	Maryland		Washington
Vermont		North Carolina	**Division 8**	
	Division 4	South Carolina	**Mountain**	
Division 2	**West North Central**	Virginia		
Middle Atlantic		West Virginia	Arizona	
	Iowa		Colorado	
New Jersey	Kansas	**Division 6**	Idaho	
New York	Minnesota	**East South Central**	Montana	
Pennsylvania	Missouri		Nevada	
	Nebraska	Alabama	New Mexico	
	North Dakota	Kentucky	Utah	
	South Dakota	Mississippi	Wyoming	
		Tennessee		

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

U.S. Census Region Pneumonic	
ENC	East North Central
ESC	East South Central
MAC	Middle Atlantic
MTN	Mountain
NEC	New England
PAC	Pacific
SAC	South Atlantic
WNC	West North Central
WSC	West South Central

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Appendix C: Literature Review[17]

There are many studies on the price and income elasticities of residential energy goods in general, and of residential natural gas demand in particular. Table 1 below lists some of these studies, along with the short-run and long-run estimates. See Dahl and Roman (2004) and Dahl (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). Common drawbacks of these studies are: (1) they do not include data that contain the recent increases in residential natural gas prices, (2) they do not focus on the winter season demand, (3) they do not contain company level data across the entire US, and (4) most do not allow for a non-price related decline in use per customer that occurs automatically as consumers replace old inefficient appliances with newer more efficient ones.

The AGA study overcomes the missing elements in the existing literature by looking at individual company level winter season monthly data from all nine US Census Regions over the period 1981 to 2006. Also, the AGA study allows for a naturally occurring decline in use per customer that results from the replacement of old inefficient gas appliances with newer more efficient models.

There have been many papers written that estimate the price elasticity of residential demand for natural gas. A partial list of these papers is given in the references section. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to as high as –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to as high as –3.42 in Beirlein, Dunn and McConnon (1981).

It is fair to say there is no real consensus on residential natural gas price elasticity demand estimates. For overall residential energy demand in general, the median estimate of short-run price elasticity is about –0.2, with the long-run dynamic models with lagged dependent variables yielding a median estimate of about –0.48. For natural gas in particular, using EIA state level aggregate data, Maddala, et. al. (1997) estimate the average short-run price elasticity of natural gas is –0.1 and the long-run price elasticity of residential natural gas demand is –0.27.

[17] This appendix benefited from discussions and on-going research by Professor Carol Dahl, the Colorado School of Mines, Golden, Colorado. All errors are ours.

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Table C.1
Residential Price Elasticity Estimates

Authors	Data	Estimation Method	Short-run	Long-run
Balestra & Nerlove (1966)	Pooled: 36 States for 1957-62)	GLS(EC)	NA	-0.63
Jaskow & Baughman (1976)	Pooled: 48 States for 1968-72	OLS	-0.15	-1.01
Berndt & Watkins (1977)	Pooled: Ontario and British Columbia for 1959-74	Maximum Likelihood	-0.15	-0.69
Hewlett (1977)	Cross Section: New York State household survey	OLS	NA	-0.45
Hewlett (1977)	Pooled: New York State customer survey for 1976 and 1977.	OLS	NA	-0.17
Beirlein, Dunn & McConnon (1981)	Pooled: 9 States for 1967-77	OLS	-0.23	-2.90
		GLS (EC)	-0.23	-2.96
		GLS (EC-SUR)	-0.05	-3.42
Barnes, Gillingham & Hagemann (1982)	Pooled: 10,000 households in 23 US cities. Quarterly data for 1972-73.	IV	-0.68	NA
Green & Gilbert (1983)	Cross-Sectional: non-poverty homeowners	OLS	NA	-1.25
	and poverty homeowners	OLS	NA	-1.09
Blattenberger, Taylor, & Rennhack (1983)	Pooled: 48 states for 1961-74	GLS (EC)	-0.32	-0.39
Green, Salley, Grass & Osei (1986)	Pooled: between 6 and 7 thousand households for 1974 to 1979.	OLS	-0.16	NA

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Appendix D: Statistical Hypothesis Testing

The practical question that is addressed in statistical hypothesis testing concerns the relative strength of some "treatment"; such as does price have an impact on weather normal use per household natural gas demand. The question addressed might be: Do the data contained in the sample present sufficient evidence that increases in price lead to a lower use per household natural gas demand?

The reasoning employed in testing a hypothesis bears a striking resemblance to the procedure used in a court trial. In tying a person for a crime, the court assumes the accused innocent until proven guilty. The prosecution collects and presents all the available evidence in an attempt to contradict the "not guilty" hypothesis and hence to obtain a conviction. However, if the prosecution fails to disprove the "not guilty" hypothesis, this does not prove that the accused is "innocent" but merely that there is not sufficient evidence to conclude that the accused is "guilty".

The statistical problem in this study portrays "natural gas price" as the accused. The hypothesis to be tested, called the **null hypothesis**, is that price does not negatively impact the weather normal use per household natural gas demand. The evidence in this case is contained in the sample drawn from the population of LDCs who supply this demand. The researcher, playing the role of the prosecutor, believes that an **alternative hypothesis** is true - namely, that natural gas price does have a negative impact on natural gas use per household demand. Hence, the researcher attempts to use the evidence contained in the sample to reject the null hypothesis (no impact of natural gas price on natural gas demand) and thereby to support the alternative hypothesis, the contention that price does in fact inversely impact natural gas demand.

The statistician will calculate a test statistic from the information contained in the sample. All possible values the test statistic may assume are divided into two groups – one called the rejection region and the other the acceptance region. After the sample is collected the test statistic is calculated and observed. If the test statistic takes on a value in the rejection region, the null hypothesis is rejected. Otherwise, one fails to reject the null hypothesis.

You will notice that the researcher is faced with two possible types of errors. On the one hand, the researcher might reject the null hypothesis when it is true, and falsely conclude that natural gas price does negatively impact the natural gas demand. This would result in forecasting lower revenues after a rate increase than would actually be the case. On the other hand, the researcher might decide not to reject the null hypothesis when it is false, and falsely conclude that natural gas price does not impact natural gas demand. This error would result in forecasting higher revenues after a rate increase than would actually be the case.

Rejecting the null hypothesis when it is true is called a Type I error for a statistical test. The probability of making a type I error is usually denoted by the Greek symbol α, and is referred to as the "statistical significance level". In practice some common values used for

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α are 0.10 (a 10 percent chance of a Type I error), 0.05 (a 5 percent chance of a Type I error), 0.025 (a 2.5 percent chance of a Type I error), and 0.01 (a 1 percent chance of a Type I error).

The probability α will increase or decrease as we increase or decrease the size of the rejection region. Then why not decrease the size of the rejection region and make α as small as possible? Unfortunately, decreasing α increases the probability of not rejecting the null hypothesis when it is false and some alternative hypothesis is true. This second type of error is called the type II error for a statistical test and its probably is commonly denoted by the Greek symbol β. More formally, accepting the null hypothesis when it is false is called a type II error for a statistical test. The probability of making a type II error when some specific alternative is true is denoted by β.

Notice that both errors cannot be committed simultaneously. A type I error is possible only if the decision is to reject the null hypothesis; a type II error is possible only if the decision in to not reject the null hypothesis.

When the null hypothesis is rejected in favor of the alternative hypothesis, it is called a statistically significant test. When one fails to reject the null hypothesis, it is referred to as a statistically insignificant test.

As noted on page 29 of Maddala (2001), a statistically significant test means, "sampling variation is an unlikely explanation of the discrepancy between the null hypothesis and the sample values (estimate)". On the other hand, a statistically insignificant test means, "sampling variation is a likely explanation of the discrepancy between the null hypothesis and the sample value".

The appropriate test statistic for the null hypotheses tested in this report is the t-statistic, which is reported for each of the coefficients in equations (4a) and (4b). For sample sizes larger than 120 and for an alternative hypothesis that states the price coefficient is less than zero, a t-statistic less than -1.28 is statically significant at the 10 percent level, a t-statistic less than -1.64 is statistically significant at the 5 percent level, a t-statistic less than -1.96 is statically significant at the 2.5 percent level, and a t-statistic less than -2.33 is statistically significant at the 1 percent level.

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Table 3
Percent of Total Residential Customers Represented by the AGA Sample

Census Regions	Census Abbreviation	Number of participating LDCs	Coverage
East North Central	ENC	3	8%
East South Central	ESC	3	11%
Mid-Atlantic	MAC	6	45%
Mountain	MTN	5	42%
New England	NEC	8	50%
Pacific	PAC	5	39%
South Atlantic	SAC	5	17%
West North Central	WNC	3	20%
West South Central	WSC	8	32%

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MAINE PUBLIC UTILITIES COMMISSION

REPORT on UTILITY INCENTIVES MECHANISMS

for the
PROMOTION OF ENERGY EFFICIENCY
and SYSTEM RELIABILITY

Presented to the
Utilities and Energy Committee
February 1, 2004

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EXECUTIVE SUMMARY

I. INTRODUCTION

During its 2003 session, the Legislature passed An Act To Encourage Energy Efficiency and Security. The Act directs the Public Utilities Commission to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution utilities to promote energy efficiency and the security and robustness of the electric grid. The Act requires that the Commission submit a report to the Joint Standing Committee on Utilities and Energy by February 1, 2004.

In broad outline, the Commission has concluded that the incentives utilities currently have under rate cap regulation to increase sales, although magnified to some degree, are similar in kind to the incentives they had under more traditional regulation. Moreover, it does not appear that utilities currently acting on these incentives have a significant opportunity to blunt the effectiveness of current efficiency and conservation programs in Maine, especially now that those programs have been removed from utility control. Finally, while there are a number of tools available to the Legislature and the Commission that could to some degree lessen the remaining utility incentives to frustrate conservation efforts, these tools are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects. For these reasons, the Commission does not recommend that any major revisions to Maine's current regulatory policies concerning utility incentives and conservation be undertaken.

In addition, the Commission believes that the current system of ensuring adequate service reliability through objective service quality metrics, backed by meaningful penalties, incorporated as part of a utility's alternative rate plan, along with the Commission's ability to use its traditional tools to ensure adequate service, is working well. Accordingly, the Commission recommends that no legislative changes be made in this area. The Commission will continue to monitor Maine's transmission and distribution utilities' service quality performance and refine the standards and penalty mechanisms in ways that improve their operation.

The report is structured into sections that contain discussions and analyses in the following areas:

- **Maine's Current Regulatory Framework**
- **Analysis of Current Regulatory Mechanisms**
- **Alternative Regulatory Mechanisms to Promote Efficiency and Reliability**
- **Other State Mechanisms**
- **Recommendations and Alternatives**

II. MAINE'S CURRENT REGULATORY FRAMEWORK

The report provides background on the utility regulatory framework in Maine. The report describes the attributes of the rate-setting methodology referred to as traditional regulation and the impact of traditional regulation on rates and rate design, operational efficiency, reliability incentives, and efficiency incentives. The report then discusses the development of alternative regulation in Maine beginning in the early 1990s referred to as Alternative Rate Plans or ARPs.

The report describes how regulatory structures changed after the restructuring of Maine's electric industry in 2000. Prior to industry restructuring, the Maine Commission regulated all aspects of retail transactions between Maine utilities and its ratepayers. After industry restructuring, the generation portion of electricity service was no longer subject to rate regulation and the regulated portion of electricity service was broken up into four pieces: (1) the generation component; (2) the transmission component; (3) the stranded cost component; and (4) the distribution delivery component. The report discusses the regulatory structures that now govern these four distinct components. In addition, the impacts of industry restructuring on utility rate design and the obligation of utilities to conduct conservation programs are reviewed.

III. ANALYSIS OF CURRENT REGULATORY MECHANISMS

-

Electricity rates currently paid by consumers in Maine are a composite of competitive and regulated services, and reflect a variety of ratemaking methodologies that include both traditional and alternative regulation. The report provides an analysis and discussion of the impact of this regulatory mix on rate levels and operational efficiencies, system reliability (both on a regional and distribution system level), energy efficiency, utility rate structures, and economic development incentives.

IV. ALTERNATIVE REGULATORY MECHANISMS TO PROMOTE EFFICIENCY AND RELIABILITY

The report presents and discusses regulatory mechanisms that can be used to alter utility financial incentives with respect to energy efficiency and system reliability. These are revenue decoupling, lost revenue adjustments, return on equity adjustments, shared savings mechanisms, service quality standards, direct pass-through of costs, and a fixed charge rate design. The report includes tables that illustrate the bill impacts for residential and small commercial customers of moving to a completely fixed charge rate design. A table at the end of the section summarizes the incentive impacts of various regulatory mechanisms.

V. OTHER STATE MECHANISMS

The Commission conducted a survey of other states and a literature search to determine the existence of possible mechanisms that can be used to affect or alter utility financial incentives with respect to energy efficiency and conservation and system reliability. The results of the research are presented in the report and summarized in tables.

VI. RECOMMENDATIONS AND ALTERNATIVES

The report presents Commission recommendations regarding utility incentive mechanisms with respect to system reliability and energy efficiency, and viable alternatives that

can address legislatively specified policies and goals.

The issues involving system reliability are relatively straightforward. The Commission's view is that, as a general matter, the current regulatory framework has produced a reasonable balance between system reliability and ratepayer cost. Accordingly, no major changes to the regulatory scheme are recommended to address reliability incentives.

The issues involving energy efficiency and the promotion of electricity consumption are relatively more complex. The Legislature must consider in the first instance whether the current incentives that utilities have to promote the use of electricity raise substantial public interest concerns. The threshold question in this context is whether it is the policy of this State to discourage the consumption of electricity. If this is the policy of the State, the next consideration is whether utilities are particularly effective in promoting the use of electricity and thereby frustrating the State's ability to attain its policy goal. Finally, if both questions are answered in the affirmative, in the Commission's view the Legislature should consider whether potential changes to the regulatory structure to alter utility incentives might nevertheless create greater problems than they solve.

The Commission expresses no opinion on whether the State should adopt a policy that the consumption of electricity is against the public interest. However, the Commission has serious concerns regarding the potential consequences of efforts to remove the financial incentives of utilities to promote their product through fundamental changes in regulatory structure or rate design.

A primary question is whether the current regulatory framework is subverting efforts to promote conservation and the efficient use of electricity. The Commission's view is that the current framework does not have this effect. The Commission has some limited evidence that utility efforts to promote consumption are not particularly effective. More importantly, however, the Commission's view is that conservation and energy efficiency are driven more by customer decisions than by utility action. Accordingly, it is more important that consumers have proper price signals to conserve and that the State retain a vibrant state-wide conservation program (i.e., the Commission's Efficiency Maine program) than it is to change utilities' actions.

It is for these reasons that the Commission recommends no fundamental change in the current regulatory structure to address utility financial incentives regarding the consumption of electricity. Nevertheless, the report outlines and evaluates several alternative approaches if the Legislature decides that public policy requires that current financial incentives should be altered.

Recommended Regulatory Approach

The Commission recommends that no fundamental changes be made to the current regulatory structure to alter utility financial incentives.

Rate Cap Regulation

The Commission recommends that multi-year rate cap plans remain the basic

regulatory approach for Maine's T&D utilities' distribution delivery rates.

System Reliability Mechanisms

The Commission recommends that service quality standards continue as the primary means to ensure adequate system reliability and that efforts continue to be made to improve the operation of the standards.

Energy Efficiency Mechanisms

The Commission does not recommend that regulatory mechanisms be adopted to alter utilities' current incentives with respect to electricity consumption and energy efficiency.

Rate Design

The Commission recommends against the adoption of a fixed charge rate design for the primary purpose of removing utility incentives to promote electricity consumption.

Alternative Approaches

If the Legislature determines that mechanisms should be employed to change utility incentives with respect to energy efficiency or system reliability, the report discusses approaches that should be considered.

Fixed Charge Rate Design

In the event the Legislature decides that some regulatory change should occur to eliminate utility financial incentives to promote electricity consumption, the Commission recommends that a legislative mandate be adopted that directs the Commission to move towards a fixed charge rate design. Because movement to a fixed charge rate design would involve substantial bill impacts for many customers (e.g., an increase from $7.18 to $35.13 for CMP's smallest residential customers), the Legislature should consider mandating that rate design changes occur gradually over time.

Revenue Reconciliation Stranded Cost Rate-Setting

In the event that the Legislature desires to take steps to address incentives regarding the promotion of electricity consumption, it should consider amending 35-A M.R.S.A. § 3208 to clearly authorize the Commission to adopt revenue and cost reconciliation mechanisms in setting stranded cost rates. If such a mechanism were adopted, a utility's incentive to increase sales would be reduced, although not eliminated, because a substantial amount of utility costs would continue to be recovered through usage sensitive charges.

Return on Equity Adjustment Mechanism

A mechanism whereby a utility's return on equity is adjusted, either up or down, based on its performance in specified areas can be an effective means to impact incentives.

The mechanism is subjective by its nature and the Commission would make determinations based primarily on its expert judgment. The approach is inconsistent with current rate plans and implementation is likely to be extremely contentious. However, a return on equity adjustment mechanism could be made part of a multi-year rate plan with rate adjustments occurring as part of the annual ARP reviews.

Multi-Year Revenue Cap

If the Legislature determines that the State's basic regulatory structure should be changed from the current rate cap regulation to alter incentives so utilities are financially neutral to electricity sale levels, a multi-year revenue cap program for establishing distribution rates can be considered. This type of revenue cap mechanism, if it can be designed correctly, would continue to provide utilities with the incentive to seek operational efficiencies and to reduce their cost of service. However, the Commission has substantial concern over unintended consequences that may accompany the adoption of a regulatory structure that is so dependent on unpredictable events.

Prohibition or Regulation of Promotional Activities

If the Legislature determines that utility promotion of electricity consumption is a serious public interest problem, the most direct solution would be a legislative ban or regulation of promotional activities. Such an approach would raise First Amendment issues that the Commission has not analyzed. The most direct approach would be a ban on promotional advertising. A less intrusive approach would be for all such advertising to include some type of required statement, such as information on the environmental impacts of electricity consumption.

I. INTRODUCTION

During its 2003 session, the Legislature passed An Act To Encourage Energy Efficiency and Security.[1] The Act directs the Public Utilities Commission ("Commission") to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution ("T&D") utilities to promote energy efficiency and the security and robustness[2] of the electric grid. The Act requires that the Commission submit a report to the Joint Standing Committee on Utilities and Energy by February 1, 2004.

As a vehicle for conducting its investigation, the Commission initiated an Inquiry on June 18, 2003.[3] As part of the Inquiry, the Commission solicited written comment from interested persons on all issues relevant to the investigation, met or had discussions with entities having expertise in the area of utility incentives, and conducted a survey and other research into mechanisms used in other states to promote energy efficiency and grid reliability. Subsequently, the Commission released a draft report, sought written comment on the draft report from all interested entities, and held a public meeting on all issues relevant to the investigation.[4]

In broad outline, the Commission has concluded that the incentives utilities currently have under rate cap regulation to increase sales, although magnified to some degree, are similar in kind to the incentives they had under more traditional regulation. Moreover, it does not appear that utilities currently acting on these incentives have a significant opportunity to blunt the effectiveness of current efficiency and conservation programs in Maine, especially now that those programs have been removed from utility control. Finally, while there are a number of tools available to the Legislature and the Commission that could to some degree lessen the remaining utility incentives to frustrate conservation efforts, these tools are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects. For these reasons, the Commission does not recommend that any major revisions to Maine's current regulatory policies concerning utility incentives and conservation be undertaken.

In addition, the Commission believes that the current system of ensuring adequate service reliability through objective service quality metrics, backed by meaningful penalties, incorporated as part of a utility's alternative rate plan, along with the Commission's ability to use its traditional tools to ensure adequate service, is working well. Accordingly, the Commission recommends that no legislative changes be made in this area. The Commission will continue to monitor Maine's transmission and distribution utilities' service quality performance and refine the standards and penalty mechanisms in ways that improve their operation.

This report is structured as follows:

- **Section II—Maine's Current Regulatory Framework:** Description of Maine's regulatory framework and corresponding utility incentives.
- **Section III—Analysis of Current Regulatory Mechanisms:** Analysis and discussion of the impact of the current regulatory framework on rate levels and operational efficiencies,

energy efficiency and reliability incentives, utility rate structures, and economic development incentives.

- **Section IV—Alternative Regulatory Mechanisms to Promote Efficiency and Reliability:** Discussion of alternative regulatory mechanisms that can affect or alter utility efficiency and reliability incentives.

- **Section V—Other State Mechanisms:** Review of regulatory approaches used in other states to address energy efficiency and system reliability incentives.

- **Section VI—Recommendations and Alternatives:** Presentation of Commission recommendations regarding utility incentive mechanisms and viable alternatives that can address legislatively specified policies and goals.

II. MAINE'S CURRENT REGULATORY FRAMEWORK

A. Background

1. Traditional Regulation

Rates and Rate Design

Pursuant to the provisions of section 301 of Title 35-A, the rates set by the Public Utilities Commission must be just and reasonable. This means that the rates must be fair to the consumer and at the same time must provide the utility with the opportunity to recover its operating expenses and to earn a fair return on its investment. For nearly a century, the Commission attempted to accomplish these objectives through establishing rates based on a rate-of-return or cost-plus rate-setting methodology that is typically referred to as traditional regulation.

Under traditional regulation, utility rates are set through periodic litigated rate cases. In these cases, the Commission examines a utility's underlying costs, current and expected revenues, and reasonable rate of return on capital investment. The Commission prospectively establishes rates to allow utilities a reasonable opportunity to recover their prudent costs[5] of providing safe and adequate service, as well as a reasonable return on shareholder investment. Rate cases are adjudicatory in nature, and can be initiated by the utility, by the Commission, or through petition of a utility's ratepayers. A contested rate case is an extremely complex and imprecise undertaking in the context of multi-million dollar utility companies. Such cases generally take a year to process and resolve, and require a substantial devotion of the resources of the Commission, the utility, the Public Advocate, and interested intervenors.

As part of the rate-setting process, the Commission must also design rates which allow the utility an opportunity to recover its revenue requirement (operating expenses plus a return of and on investment). Revenue requirements can be recovered through three different types of charges or rates: customer or fixed charges;[6] usage or energy (kWh) charges; and demand (kW) charges.

Pursuant to the enactment of the Electric Rate Reform Act in the mid-1980s,[7] the Commission endeavored to design electric rates in a manner that more closely reflected the underlying costs of service. This involved establishing rates based on the marginal cost of service, designing rates to reflect cost differences between seasons and time-of-day, and adopting inverted block rates (in which rates increase with higher usage amounts) for residential customers. This approach to ratemaking was intended to promote economic efficiency and the proper allocation of societal resources.

Operational Efficiency

Because utility rates are reset periodically based on an examination

of the utility's ongoing costs, traditional regulation does not provide strong incentives for utilities to conduct their business in the most efficient manner or to provide their service at the lowest possible cost. As a practical matter, the Commission's traditional review cannot uncover all potential inefficiencies, and the regulatory approach does not provide incentives for efficient business operations to nearly the same degree as a competitive market. Unlike a competitive business that must price its product based on what the market will bear, a utility whose costs are rising, or whose shareholder returns are considered insufficient, can file for a rate increase. Conversely, a utility that is able to reduce its costs through efficiency measures faces the possibility that ratepayers or the Commission will initiate a rate case to lower rates on the grounds that the utility's returns are too high. Thus, the traditional regulatory system does not instill the type of business discipline that occurs in competitive markets.

Reliability Incentives

Under traditional regulation, utilities were guaranteed the opportunity to obtain a fair return on their total capital investment (referred to as ratebase). In addition, under certain circumstances, a utility might be able to enhance its earnings per share by making additional investments in its plant.[8] Given the utilities' near guarantee of recovery of investment in their systems, the incentive for utilities was to "gold-plate" their systems to some degree to reduce any potential reliability problems that might lead to negative public reactions and greater Commission scrutiny. Traditional regulation has limited effectiveness in protecting against "overbuilding" and its resulting unnecessary increases in rates.

To the extent that reliability problems existed despite the general incentive in favor of capital expenditures,[9] the primary remedy under traditional regulation was for the Commission to react to individual customer complaints. In addition, as part of a rate case proceeding, the Commission would ordinarily hold public witness hearings where customers of the utility could testify about any service problems. This testimony was often anecdotal and did not provide an objective basis to determine whether the utility was in fact providing adequate and reliable service on a system-wide basis. If the Commission found that the utility was violating its general obligation to provide reasonably reliable and adequate service, the primary tool for addressing the matter was to penalize the utility through a reduction in the utility's return on equity. While any attempt to reduce a utility's return on equity due to service quality issues would likely be contested and subject to court review, the potential for the Commission to act in this manner provided some incentive for utilities to maintain adequate service.

Efficiency Incentives

Under traditional regulation, utilities have the financial incentive to promote the consumption of electricity, and little incentive to pursue energy efficiency or conservation.[10] This is because total company revenues (and thus profits) are a function of sales volumes. Thus, every kilowatt-hour sold increases profits, while every kilowatt-hour saved lowers profits. [11] The disincentive with respect to energy efficiency and conservation is diminished to some degree by the ability of utilities to make up for lost revenues through periodic rate cases. However, rate cases are costly and take a substantial amount of time during which

the impact of lost revenues continues, and the ultimate result is higher utility rates that could lead to reduced business and public bad will. The financial incentive between rate cases is for a utility to act to increase electricity sales.

Prior to the restructuring of the electric industry, utilities were obligated to pursue energy efficiency and conservation measures, if such measures were less costly than the generation supply alternative. Because of the inherent disincentive against reduced consumption, the Commission was required to carefully monitor utility operations to ensure that utilities acted in a manner consistent with their legal obligations.

2. Development of Alternative Regulation

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In late 1993, following a series of rate increases resulting from a number of causes, including declining sales brought on by a downturn in the economy, introduction of a new rate design, and increases in utility costs above the rate of inflation, the Commission concluded that it should consider setting Central Maine Power Company's ("CMP") rates by means of a rate cap approach. Under a rate cap approach, CMP's rates would be reset based on an external index over a multi-year period. The Commission concluded that a multi-year price-cap, also referred to as an incentive rate plan or Alternative Rate Plan ("ARP"), could provide the following benefits to Maine ratepayers: (1) electricity prices would continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability were more likely; (3) regulatory "administration" costs could be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) risks could be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and (5) because exceptional cost management could lead to enhanced profitability for shareholders, stronger incentives for cost minimization would be created.[12] Because the ability of a utility to file for a rate increase is greatly restricted under an ARP, the Commission noted that there is an enhanced incentive, relative to traditional regulation, for a utility to cut costs in ways that could damage system reliability and to increase consumption by cutting back efficiency programs.

The Commission approved an alternative rate plan for CMP in 1995 that was among the first price-cap plans for any electric utility in the country.[13] CMP's first five-year price-cap plan, also now referred to as ARP I, reset CMP's rates annually based on an external index calculated by inflation minus a productivity offset, plus or minus earnings outside a deadband and/or certain costs which qualified as mandated costs. To address incentives that might have been created for the utility to cut costs at the expense of system reliability, the plan also included substantial financial penalties for failure to attain the standards set forth in the ARP's Service Quality Index ("SQI"). ARP I's SQI measured CMP's performance in five areas of which two addressed reliability and three concerned customer service.

The reliability indices included the System Average Interruption Frequency Index ("SAIFI"), which measures the average frequency of sustained interruptions per customer over the year, and the Customer Average Interruption Duration Index ("CAIDI"), which is a calculation of the average time required to restore service to the average customer per sustained interruption. ARP I's SQI provided for penalties of up to $3 million if CMP failed to meet the SQI

standards in any one year. In approving ARP I, the Commission concluded that the specific service quality standards of the SQI, with automatic penalties assessed if service deteriorated beyond baseline levels, was superior to the traditional tools of penalizing the Company for poor service through litigated proceedings.

In addition, to address the enhanced disincentive regarding energy efficiency and conservation, ARP I required CMP to submit annual energy resource plans, which included kilowatt-hour and kilowatt savings associated with demand side management ("DSM") activities. In the event CMP failed to achieve 90% of targeted DSM savings in any one year, it would be subject to a penalty of between $1.5 million to $5 million. This mechanism was effective in ensuring that CMP's conservation activities produced energy savings at the targeted levels. However, the motivational impacts of the targets ceased as soon as the targets were met.

B. Regulatory Structures After Industry Restructuring

For the entire 20th century, Maine's utilities were vertically integrated and were monopolies with respect to all aspects of providing and delivering the electricity "product." Because of their monopoly status, the Maine Commission regulated all aspects of retail transactions between Maine utilities and its ratepayers.

On March 1, 2000, Maine's electric industry was restructured to provide Maine consumers with the opportunity to purchase generation services from a competitive market and as of that date, the generation portion of electricity service was no longer subject to rate regulation in Maine. As a result of restructuring, the bundled electricity "product" has been broken up into four pieces: (1) the generation component; (2) the transmission component; (3) the stranded cost component; and (4) the distribution delivery component.

In this portion of the report, the Commission discusses the regulatory structures that now govern these four distinct components. In addition, the impacts of industry restructuring on utility rate design and the obligation to conduct conservation programs are reviewed.

1. Generation Component

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As part of industry restructuring, investor-owned electric utilities[14] in Maine were required to divest their generation assets on or before March 1, 2000, and to the extent that a utility desires to enter the competitive retail generation supply market, such activity has to occur through a separate corporate affiliate. Upon restructuring, utilities no longer have the obligation to ensure an adequate supply of generation, and construction of new generation as well as the continued operation of existing generation is now subject to market forces. Like other competitive businesses, generators and competitive electricity suppliers have a direct financial interest in promoting the sale of their products.

2. FERC Regulation of Transmission Rates

The unbundling of generation costs from utility rates has resulted in the

Federal Energy Regulatory Commission ("FERC") asserting jurisdiction over retail transmission rates. Under FERC regulation, transmission rates are set through a formula in which rates are established annually based on the utility's prior year's costs and revenues. This type of regulation provides little incentive for operational efficiency because rates are based directly on utility costs. Because rates are reset annually, the FERC ratemaking methodology provides even less incentive for operational efficiency than traditional regulation in that a utility's actual costs are, in essence, automatically recovered. The primary means to ensure some reasonable level of efficiency and to prevent the recovery of imprudent or otherwise impermissible costs from ratepayers is through Commission intervention as a party in the FERC's annual implementation of the transmission rate formulas. The Commission routinely intervenes in Maine utilities' annual formula filings in an effort to ensure that transmission rates are just and reasonable.

FERC's ratemaking approach should generally have the effect of reducing utility reluctance to invest in reliability improvements in that timely cost recovery is essentially ensured. However, utilities have recently argued before FERC (in the context of a proposal to form a Regional Transmission Organization) that the existing regulatory system, given the risks associated with the construction of transmission facilities, does not provide sufficient incentives for the utilities to invest in their transmission systems. The utilities are asking FERC for significantly enhanced allowed returns as an inducement to construct transmission facilities.[15]

Because FERC's ratemaking methodology annually updates rates based on the previous year's revenues, the utility's incentive to increase sales and disincentive to promote energy efficiency and conservation is reduced to some degree relative to traditional or rate cap regulation. The overall impact of FERC regulation on utilities' motivation regarding sales is not substantial because for most customers transmission is not a substantial part of the total utility rate.[16]

3. Stranded Cost Rate Setting

Under the provisions of the Restructuring Act, the Commission was directed to determine and permit recovery of each utility's stranded costs which are defined as the legitimate, verifiable and unmitigatible costs made unrecoverable as a result of the restructuring of the electric industry.[17] Prior to the onset of retail access, and periodically since that time, the Commission has set stranded cost rates for each of the State's investor-owned utilities. The difference between the ongoing costs of qualifying facility ("QF") contracts and the value of the output of those contracts in the wholesale competitive market, generation-related regulatory assets, and costs related to Maine Yankee are the primary components of stranded costs in Maine.

Because a major component of each of the utility's stranded costs is dependent on the results of the sales of the output from the utility's QF contracts, the Commission has concluded that it is not feasible to employ an alternative rate setting mechanism for stranded costs. Therefore, the Commission has continued to rely on traditional cost of service rate setting for this category of costs. The Commission has set stranded costs for multi-year periods which run concurrently with the utility's sale of its QF entitlements.

4. Distribution Delivery Rates

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During 2000, the Commission approved a second alternative rate plan for CMP (referred to as ARP 2000) applicable in the newly restructured environment.[18] Because generation service is now subject to market competition , and because FERC has asserted jurisdiction over transmission service following a state's unbundling of generation from delivery service, ARP 2000 only applies to distribution delivery rates and service. Similar to ARP I, ARP 2000 adjusts rates annually by a formula of inflation minus a productivity offset adjusted for mandated costs, earnings sharing, and service quality penalties. ARP 2000's SQI mechanism contains the same two indices, CAIDI and SAIFI, to measure reliability. Although CMP's revenues have decreased by about one-third as a result of restructuring, the ARP 2000 plan increased the maximum penalty level for failing to meet the SQI standards from $3.0 million to $3.6 million.

During 2002, the Commission approved an ARP for BHE. [19] Similar to CMP's ARP 2000, the BHE ARP applies only to distribution rates, contains CAIDI and SAIFI performance metrics, and requires BHE to file an Annual Reliability Improvement Report.

At the present time, the only investor-owned utility whose distribution rates remain subject to traditional regulation is MPS. During 2003, MPS submitted a proposal to the Commission requesting a $1.267 million increase in distribution revenues as a "starting point" adjustment for its proposed seven-year ARP. The Commission approved a stipulation which resolved the Company's "starting point" revenue requirement request but did not address MPS's proposed ARP. [20] Under the terms of the stipulation, MPS was given until the end of 2003 to determine whether it wanted to pursue its ARP proposal. MPS has informed the Commission that it does not wish to pursue its proposal at this time.

5. T&D Rate Design

Upon the restructuring of the industry, the Commission removed generation-related costs from utility rates in a manner that avoided negative overall rate impacts for customers and customer classes. The result is that current T&D rates continue to have a basic design that existed when utilities provided generation service. Under that design, T&D utility revenues are primarily recovered through usage sensitive energy charges for the utilities' residential and small commercial customers, and through usage sensitive energy and demand charges for the utilities' large commercial and industrial customers. Currently, a very small percentage of utilities' revenues are recovered through fixed or customer charges that do not vary with usage.

6. Conservation Obligations

Prior to industry restructuring, utilities had the obligation to provide generation supply through a least cost mix of resources that included conservation or DSM programs. In particular, utilities were required to pursue DSM if less costly than an equivalent amount of supply. Thus, utilities were required to conduct DSM even though it was against their financial interest to reduce electricity consumption.[21]

The obligation of Maine utilities to provide generation services through a least cost mix of resources ended with the restructuring of the industry. Utilities are now solely "wires" companies. As such, the pursuit of conservation and DSM are no longer an integral part of the service provided by Maine utilities. In recognition of this change and the continued financial incentive that utilities have not to reduce electricity consumption, the Legislature, pursuant to the recently enacted Conservation Act, transferred responsibilities to implement and administer energy efficiency programs to the Commission.[22]

III. ANALYSIS OF CURRENT REGULATORY MECHANISMS

Electricity rates currently paid by consumers in Maine are a composite of competitive and regulated services, and reflect a variety of ratemaking methodologies. This section of the report provides an analysis and discussion of the impact of this regulatory mix on rate levels and operational efficiencies, energy efficiency and reliability incentives, T&D rate structures, and economic development incentives.

A. Rate Levels and Operational Efficiencies

In 1992, the Commission was faced with what amounted to a ratepayer revolt.[23] Numerous ratepayers expressed concern with both the high level and unpredictability of CMP's rates. On an overall basis, the Commission views the alternative rate plans adopted in Maine to date to have effectively addressed these concerns. Rate stability and predictability have been enhanced by the ARP's use of a pre-established formula to set rates over a period of years. The ARP mechanism has reduced electric rate volatility by limiting rate changes to once a year and has allowed customers to anticipate and take into account future levels of electricity rates.[24]

Not only have the ARPs provided utility ratepayers with a greater rate stability and rate predictability, but they have also had a positive impact on overall rate levels. The annual productivity offsets in CMP's ARP 2000 range from a low of 2.0% in 2002 up to 2.9% in 2007. During the course of ARP 2000, these productivity offsets will serve to decrease distribution rates in real dollar terms by 18.0%. Under the BHE ARP, BHE's distribution rates decreased by 2.5% last year, and are projected to decrease by approximately 2.75% next year, and given current inflation forecasts, by 2.75% in 2005 and by 2.8% in both 2006 and 2007.

By severing the ratemaking link between a utility's rates and its costs over a multi-year period and restricting the ability of utilities to file for rate increases whenever their costs increase or revenues diminish, the rate cap plans have provided a powerful incentive for the utilities to reduce costs and increase operational efficiency. Moreover, the operational efficiency incentive is enhanced under rate cap plans in that utilities are able to maintain the benefits of their successful cost saving measures (in the form of enhanced shareholder returns) for the duration of the plan. This is in contrast to traditional regulation in which the benefits of increased operational efficiency to utility shareholders are essentially removed as soon as rates are reset in periodic rate proceedings.

Thus, the rate cap plans have been effective in mirroring competitive markets by setting prices independent of the utility's costs, and by allowing utilities to benefit from their efficiency innovations or suffer losses as a result of either inefficiencies, poor business decisions, or changes in the business climate. At the same time, the productivity offsets contained in the ARPs have worked to ensure that ratepayers receive a fair share of potential operational savings regardless of whether the utility's actual performance produced such savings.

B. System Reliability

There are two areas of reliability issues: those involving the distribution network and those involving the regional system. Most reliability problems result from problems on the local distribution network, such as wind damage, ice damage, lightening strikes, and motor vehicle accidents. Regional problems, such as the blackout that affected much of the Northeast on August 14, 2003, are rare but can have a substantial impact.

1. Regional Reliability

The regional grid is designed to be able to recover from failures of generators or transmission lines without widespread blackouts. However, on occasion (the August 14, 2003 blackout is an example) these recovery operations are not invoked or prove to be inadequate. Since the major blackout in 1965, there have been regional and national efforts to standardize planning criteria and operating protocols under the auspices of the North American Electric Reliability Council or NERC. Those efforts are aimed at eliminating regional blackouts.

State and federal efforts to restructure the electricity industry have resulted in the decentralization of decision-making related to electric system reliability. Prior to restructuring, integrated utilities controlled virtually all aspects of power supply and reliability within their respective service territories. Currently, responsibility in the New England region is divided among a wider range of entities: generators, transmission owners, electricity suppliers and ISO-NE. This decentralization, coupled with still emerging roles of the various market players has, at least arguably, resulted in a slowdown in investment, particularly in transmission facilities that could help to maintain or improve regional reliability.

At present, regional reliability concerns appear more applicable to regions other than New England. Maine currently has a substantial surplus of generation. This means that, in the event of a system problem, electric service in Maine should be maintained so long as the system reacts quickly enough to avoid an external disruption to cascade into the State.[25] Moreover, except for specific load pockets, there is generally excess generation capacity in New England.

Going forward, ISO-NE can be expected to play an increasing role in ensuring adequate regional reliability. This will occur through market rules intended to maintain adequate generation resources in the region, as well as through longer-term planning and oversight intended to ensure that adequate transmission infrastructure is in place.

2. Distribution Reliability

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Multi-year rate cap plans provide powerful incentives to minimize costs that could result in the reduction of distribution system reliability. To counteract those incentives, the plans include service quality standards that utilities must satisfy to avoid financial penalty. The adoption of the CAIDI and SAIFI metrics with automatic penalty mechanisms results in enhanced financial incentives for utilities to provide appropriate reliability and a more effective and objective way to measure service quality than the tools previously relied on by the Commission

under traditional regulation. As the Commission has gathered experience with these metrics, it has refined the service reliability evaluation methods and techniques.

Specifically, the Commission has recognized that insufficient investment and deterioration in the utility's plant might not be reflected in degradation of service until some time in the future. Accordingly, the Commission has substantially refined the service reliability information that each utility must submit to the Commission each year. Currently, CMP must submit, as part of its annual ARP filing, a distribution plant report which provides information on the age of the utility's distribution equipment and facilities, its construction budget for the past two years, and actual construction spending for the prior year.[26]

The Commission has also recognized that it is possible for a utility to maintain acceptable service levels on a system-wide average basis, but allow service to customers in certain areas (particularly less densely populated rural areas) to deteriorate. As a result, BHE and CMP are required, as part of their annual filings, to prepare and submit an Annual Reliability Improvement Report which includes a service area specific analysis of service reliability, an identification of the company's worst circuits, an analysis of each circuit's problems and the planned and/or undertaken improvements to address each problem. These reports have enabled the Commission and the Public Advocate to review service area specific problems and to engage in a constructive dialogue with the utilities to ensure that such problems are addressed.

As part of the Commission's monitoring of service reliability issues, it has also recognized that, with customers' increased use of electronic equipment (such as VCRs, digital clocks and computers), the quality of power provided to customers has become more important in recent years. Momentary power interruptions are, therefore, becoming more of a focus of consumers' perception of reliable electric service. While the impact of momentary interruptions may at times be more of a nuisance than a serious problem, frequent occurrences can damage equipment, erode public confidence, and increase the likelihood of complaints to the utilities and to the Commission. In addition, power quality problems can have an adverse effect on the State's efforts to attract high-tech industries that are very sensitive to such interruptions, as well as on the increasingly computer-dependent operations of other commercial enterprises in Maine.

The Commission, therefore, convened a statewide task force of interested stakeholders,[27] referred to as the Power Quality Task Force ("PQTF"), to investigate alternative service quality indicators and, where appropriate, to recommend new indicators for measuring power quality service performance. The PQTF investigated whether a Momentary Average Interruption Frequency Index (MAIFI)[28] should be included as an SQI indicator, and recommended that a MAIFI standard not be established at this time. Instead, the PQTF recommended that each utility collect specific service data for a two-year period which can then be used to determine if MAIFI or some other metric should be adopted to assess the quality of power provided by CMP, BHE and MPS. The data will also be used to determine if a correlation exists between customer satisfaction and momentary interruptions. If the decision is made to adopt a momentary outage metric, the metric would be incorporated into the CMP and BHE ARPs. MPS does not currently have an alternative rate plan, however, the metric could be

considered for adoption independent of a rate plan or as part of a future rate plan.

Finally, recognizing that the evaluation of service quality and reliability is an evolving and ongoing process, both the CMP ARP 2000 and the BHE ARP provide for mid-period reviews of the operation of the SQI mechanism. CMP's mid-period review was concluded in December 2003, and included a change in the exemption criteria for the CAIDI and SAIFI metrics. The exemption criteria as originally approved excluded outages that affected 10% of customers within portions of CMP's territory from the metric calculations. The outage exemption mechanism in operation had worked in an unintended manner to exclude minor outages and thus was not properly tracking CMP's service reliability. The exemption criteria were therefore changed so that only outages which affect 10% of CMP's customers on an entire service territory basis would be excluded.[29] BHE's mid-period review will occur during 2004.[30]

The Commission will continue to examine ways to improve the operation of the service quality indices.

C. Energy Efficiency

Under the Commission's stranded cost rate setting process, stranded cost rates are set for a several-year period based on a forecast of sales. Because a utility's stranded costs do not vary with volume, after stranded costs are set , the utility has a strong incentive to promote sales because all increases in sales flow directly to the utility's bottom line. While the Commission retains the authority to reset stranded cost rates during the stranded cost rate-setting period to correct substantial inaccuracies, any such change can only be made on a prospective basis. Thus, during the time a case is being litigated to correct for sales volume changes, the utility would retain the amounts collected from ratepayers above those projected to be needed to recover stranded costs. During 2003, the Commission concluded an investigation of CMP's stranded costs to address the issue of higher than projected sales.[31] Typical of traditional cost of service rate setting, the proceeding was controversial and required a significant amount of Commission staff and utility resources.

With respect to ARP rate setting in effect for distribution delivery rates, the incentive for utilities to promote electricity sales and to discourage energy efficiency and conservation are magnified to some degree relative to traditional regulation. As with traditional regulation, a utility's profits are a direct function of sales levels. However, the inability of a utility under a rate cap plan to file for a rate increase in response to increasing costs or decreasing revenues provides a greater motivation for utilities to act to increase sales over the term of the plan, as well as an enhanced financial conflict with conservation activities that serve to reduce the consumption of electricity.

The Legislature, recognizing both that utilities were no longer in the generation business and that there continued to be strong disincentives regarding the conservation of electricity, transferred the responsibility to administer energy efficiency and conservation programs from the utilities to the Commission. This dramatically changes the issue of regulatory

responses to utility financial incentives regarding energy efficiency and conservation. Utilities, either under traditional regulation (stranded cost) or alternative regulation (distribution delivery) still have the incentive to discourage conservation and promote consumption. However, utilities no longer carry out ratepayer funded conservation measures and, thus, cannot act to hinder the effectiveness of such programs through ineffective or non-performance. The result is that the importance of addressing the inherent disincentive that derives from the ratemaking process through the adoption of alternative regulatory devices or changes to rate design has been greatly diminished.

D. Rate Structures

When utilities were vertically integrated and provided generation supply, it was reasonable to rely on usage sensitive charges because a substantial amount of utility costs varied with actual ratepayer consumption. After restructuring, utilities provide only delivery service and each utility's rates must recover only the costs associated with delivery service and stranded costs. The costs to provide the delivery component of utility service are generally fixed, at least in the shorter term. In the long run, T&D utility costs vary to some degree because the sizing of facilities over the longer term depends on maximum consumption (i.e., "peak load") of customers.

Stranded costs are historic costs and, thus, do not vary with current consumption. Stranded costs, however, were incurred to provide generation service and, therefore, even though such costs do not vary with current usage, as a matter of equity, it may be argued that such costs should continue to be recovered through demand and energy charges because this tends to allocate costs to customer classes and to customers (in general, if not individually) according to their cost causation responsibilities.

The current usage-based delivery and stranded cost rates have the effect of providing the incentive for utilities to promote sales because additional sales translate into additional earnings. This is especially the case with respect to stranded costs which do not vary at all with sales volume. The current T&D utility rate design does, however, provide strong price signals for customer conservation because a substantial portion of costs remain in usage sensitive charges. Thus, lower usage results in reduced bills. It should also be noted that the existence of stranded costs in T&D rates means that rates are actually higher than the ongoing cost of service, resulting in greater incentives for customers to conserve electricity or seek grid alternatives than would actually be efficient if rates more accurately reflected the underlying costs.

During 2001, the Commission initiated an investigation to examine moving more T&D utility costs into fixed charges.[32] The investigation focused on stranded costs because there is little debate that, from an economic efficiency perspective, such costs (which are sunk) should be recovered through fixed charges. However, the proceeding was controversial. Although utilities were generally supportive of moving stranded costs into fixed charges, the intervenors generally opposed the move. The basis for the opposition was twofold: first, moving rates from usage sensitive to fixed charges would reduce the incentive of consumers to conserve their electricity usage; and second, the change would increase utility bills for low-use

customers.[33] Ultimately, the case was resolved by a stipulation that made only a very modest move to fixed charges, by targeting expected rate decreases over several years only to energy charges.[34]

E. Economic Development

Under both traditional and rate cap rate setting methodologies, utilities have a strong incentive to promote economic development of any type within their respective service territories. Economic growth leads to increased sales, which results in increased utility profits. Additionally, the management of utilities, like that of any business, has an interest in increasing the size of their business. Utilities have no particular incentive to attract energy-efficient business, as opposed to any other new enterprise (unless the utility views an energy-efficient business to be more likely to be viable over the long-term).

The financial incentive for utilities to promote economic development under ARPs is magnified relative to traditional regulation due to the inability of a utility to file for a rate increase under a rate cap plan. Generally, this magnified incentive would make it more attractive for utilities to promote energy-intensive businesses.

IV. ALTERNATIVE REGULATORY MECHANISMS TO PROMOTE EFFICIENCY AND RELIABILITY

This section of the report presents and discusses regulatory mechanisms that can be used to alter financial incentives of utilities.

A. Revenue Decoupling

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1. General Description

Revenue decoupling is a form of ratemaking intended to remove the financial disincentive that utilities have to engage in or support energy efficiency and conservation activities.[35] The mechanism also acts to remove the financial incentive to promote increases in sales. Revenue decoupling works by severing the link between a utility's sales and its profits. This is accomplished by pre-establishing a utility's "allowed" revenues, which would typically occur in a traditional rate case proceeding. These allowed revenues are periodically compared to the utility's actual revenues and the difference is tracked for ratemaking purposes in a deferred account. In the event actual revenues are greater than allowed revenues, the difference is returned to ratepayers through a rate reduction. Conversely, if actual revenues are below allowed revenues, the difference is collected by the utility through a surcharge on rates.

2. Energy Efficiency Incentives

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By establishing a ratemaking process in which the revenue a utility ultimately obtains is independent of sales levels, the financial disincentive that exists under traditional and rate cap regulation to promote energy efficiency and conservation, as well as the incentive to promote increased consumption, is removed because profits are no longer a function of sales volume. Revenue decoupling does not, however, provide any positive incentive for utilities to promote or support energy efficiency or conservation programs; it only makes them financially neutral to such activities.[36]

The implementation of revenue decoupling would reduce a utility's incentive to promote economic development to some degree in that increased electricity consumption would not increase profits. However, depending on the form of revenue decoupling, the incentive in favor of increasing the number of customers would either be enhanced or not affected.

3. Operational Efficiency, Rates and Risks

Although revenue decoupling acts to ensure pre-specified levels of revenue, it does not guarantee any level of profits. Thus, under revenue decoupling, a utility maintains its incentive to cut costs or increase efficiency in operations. This incentive to minimize costs can be enhanced through a multi-year revenue decoupling plan. Such a plan would be similar to a multi-year rate cap plan in that increased incentives for operational efficiencies occur as the result of an inability of a utility to file a rate case through the period of the plan. Like a rate cap plan, a revenue decoupling plan would include a formula (such as inflation minus productivity) by which the allowed revenue would change on an annual basis, and could also include any of the other typical attributes of a rate cap plan, such as service quality standards and earning sharing mechanisms.

Revenue decoupling mechanisms are not specific to revenue losses from efficiency or conservation activities. Revenue decoupling results in utilities being financially neutral to the impact on sales levels (either sales decreases or increases) from any cause, most notably economic conditions and the weather. Thus, revenue decoupling has the effect of shifting the risks of economic cycles and weather fluctuations from utilities to ratepayers. This impact combined with the revenue accounting deferrals inherent in revenue decoupling results in increased rate volatility and uncertainty relative to traditional or rate cap regulation.

There are, however, adjustments that can be made to a revenue decoupling mechanism to reduce the shift of risks to ratepayers. For example, the allowed revenue under a revenue cap could be normalized for weather or economic conditions, or allowed revenue could be adjusted based on the number of customers (which would leave utilities subject to economic conditions to some degree). The implementation of these types of adjustments is complicated and would not act to completely avoid the shift of risks onto ratepayers. Another mechanism that would reduce the shift of risks to ratepayers, as well as lower rate volatility impacts, is a limit on the amount of revenue that could be deferred for later recovery. Such an approach, however, would eliminate the incentive impact of the revenue decoupling once the deferral limit was reached.

The shifting of sales level risk to ratepayers that occurs with revenue decoupling might be offset to some degree by a lower cost of capital for utilities that could translate into some level of lower rates.

4. Maine's Experience with Revenue Decoupling

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Maine has experience with revenue decoupling. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling mechanism for CMP (referred to as "Electric Revenue Adjustment Mechanism" or "ERAM").[37] The "allowed" revenue was determined in a rate case proceeding and adjusted annually based on changes in the utility's number of customers. Analyses before the Commission at the time indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP's ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at

any time to adjust its “allowed” revenues.

CMP’s ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was at the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October of 1991 that would have increased rates at the time, but likely would have caused lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.[38]

By the end of 1992, CMP’s ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP’s conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.

Maine’s experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties.[39]

B. Lost Revenue Adjustments

1. General Description

Lost revenue adjustments are a common mechanism employed to reduce utility disincentives to pursue energy efficiency and conservation. The mechanism works by estimating the amount of sales that a utility has lost as a result of energy efficiency programs and reimbursing the utility for its lost revenues. The reimbursement occurs through an adjustment in utility rates. The mechanism is considered an alternative to revenue decoupling and could be implemented in conjunction with traditional or rate cap regulation. Lost revenue adjustments are not designed to, and do not, impact utility incentives to provide adequate system reliability.

2. Incentive Impacts

The mechanism, if implemented accurately,[40] makes utilities financially neutral to lost sales resulting from energy efficiency programs. However, it does nothing to impact a utility's incentive to promote increased sales, or to align a utility's interests with a state's efficiency objectives or efficiency activities by other entities for which they are not reimbursed under the mechanism. Moreover, the mechanism is relatively complex to administer, and measurement and evaluation issues are often controversial.

C. Incentive Payments/Penalties

1. ROE Adjustments

Return on equity (ROE) adjustments are a means to reward or penalize a utility for its activities. The Commission has substantial discretion to set a utility's ROE within a reasonable range or bandwidth. Thus, if a utility is found to have acted in an exemplary fashion in the promotion of State policies, the Commission could establish an ROE at the upper end of the reasonable range. Conversely, if the Commission finds that a utility has acted contrary to State policies, a lower ROE can be established.

The mechanism can be used to provide utilities with the incentive to promote energy efficiency and conservation, or to provide appropriate system reliability. As discussed above, the use of ROE adjustments is the primary tool under traditional regulation to ensure that utilities act in a manner consistent with their obligations, [41] but they can also be employed as part of rate cap or revenue decoupling regulation. The application of ROE adjustments occurs in the context of litigated proceedings, is subjective in nature, and is usually controversial.

2. Shared Savings

Shared savings mechanisms are used to provide utilities with the incentive to aggressively pursue energy efficiency and conservation programs. The mechanism works by

allowing utilities to "share" a pre-specified portion of the savings achieved from their energy efficiency and conservation programs, thus linking a utility's profits to its conservation performance. The mechanism is not applicable to system reliability incentives.

Energy efficiency and conservation programs, assuming that they are cost-effective, will cost less than a comparable amount of supply. The difference between the cost of the avoided supply and cost of the efficiency program represents overall ratepayer savings. Under a shared savings program, a utility is able to recover a portion of these savings through an upward adjustment in its rates. The mechanism is relatively complex to administer, and requires rigorous measurement and long-term verification of achieved savings.

Shared savings programs do not remove the basic utility incentive to promote consumption or to discourage conservation. For this reason, a shared savings program is often adopted in conjunction with a lost revenue adjustment or a revenue decoupling mechanism.

D. Service Quality Standards

As discussed above, the Commission has incorporated service quality standards with automatic penalty provisions as part of the alternative rate plans. In addition to penalizing a utility for service that degrades below baseline standards, a service quality standard mechanism could be designed to reward a utility for exceptional service quality. Another possible variation would be to adopt area specific standards within a utility's service territory and penalize (or reward) the utility based on its performance within portions of its service territory. While this approach has been suggested in prior Commission proceedings, the Commission has not adopted it.

It is possible to use service quality standards in the context of different rate-setting mechanisms, such as traditional rate-of-return regulation.

E. Direct Pass-Through

1. General Description

Direct pass-through of utility costs is a ratemaking mechanism that allows utilities to receive dollar-for-dollar recovery of certain categories of costs. The mechanism can be used to remove the incentive utilities may have against making expenditures in certain areas. Under the general approach to ratemaking, utilities do not receive dollar-for-dollar recovery of their expenditures. Instead, rates are set on a prospective basis using historical costs. Direct pass-through of costs is an exception to standard ratemaking that is appropriate in some circumstances. For example, particular costs that are extremely volatile and outside the control of the utility have been candidates for direct pass-through.[42] Additionally, utilities often recover the costs of publicly mandated programs through direct ratepayer pass-throughs. This is done to help ensure that utilities do not under-fund such programs to enhance their bottom line profits.

Utility expenditures on energy efficiency and conservation programs in Maine

have historically been subject to direct pass-through rate recovery. This was part of a longstanding regulatory attempt to counter utilities' natural inclination against spending money to reduce the use of its product. Utility expenditures on system reliability, however, have generally not been subject to direct pass-throughs in that they are considered a basic part of utility operations and not subject to special ratemaking treatment. However, there have been exceptions for costs resulting from unusually destructive storms, such as the 1998 ice storm.

2. Incentive Impacts

Direct pass-through of costs removes the incentive utilities have to under-fund certain programs or projects so as to enhance profits. However, any time a category of costs is recovered on a dollar-for-dollar basis, there is no financial incentive for the utility to be efficient or to minimize costs in conducting the program or project.

F. Fixed Charge Rate Design

1. General Description

Maine ratepayers' bills now consist of both unregulated and regulated prices and, within the regulated component, FERC jurisdictional and Maine jurisdictional rates. At the present time, all rates have usage sensitive components. While it would be possible to recover the entire PUC jurisdictional revenue requirement through fixed charges, a significant portion of electricity bills would remain usage sensitive.

2. Incentive Impacts

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The more a utility's costs are recovered through fixed charges, the less financial incentive it has to promote sales or to discourage energy efficiency and conservation. [43] However, unless all of a utility's costs are recovered through fixed charges, some incentive to promote consumption on the part of utilities will remain. A movement towards a more fixed charge rate design would also reduce a utility's incentive to promote economic development to some degree since increased electricity consumption would not increase profits. However, increasing the number of utility customers would have a positive impact on profits.

If T&D utility rate design were changed so that it consisted entirely of fixed charges, it would provide no financial incentive for customers to conserve their usage of electricity. However, because the supply portion of the electricity bill would continue to consist of usage-sensitive charges, there would still be some incentive for consumers to conserve. However, the motivation of consumers to conserve would be significantly reduced in that approximately two thirds of electricity bills are comprised of T&D charges.

3. Rate Impacts

Any time rate design is altered some customers benefit through lower bills, while other customers are subjected to higher bills. Therefore, a primary consideration in any attempt to move to a more fixed rate design is customer bill impacts. The movement to a fixed

rate design in particular would result in increases for customers with relatively lower usage within a class, and decreases for customers with relatively higher usage.

To illustrate the bill impact effect, the following tables show the impact on CMP's residential and small business customers if all T&D costs (including stranded costs)



were recovered through a fixed customer charge.



As the tables above illustrate, if T&D charges were fixed, CMP residential customers would pay a flat rate of $35.13 per month and small commercial customers would pay a flat rate of $63.39 per month for T&D delivery service, and lower usage customers in both classes would see significant bill increases.

The following tables show the number of customers in CMP's territory whose average monthly bill falls within various kWh ranges. A customer's bill will vary by month, so the level of bill increase or decrease will vary by month. However, these tables give an idea of the number of customers that will experience bill increases or decreases of the sizes shown above. In general, it is reasonable to estimate that, if the fixed rates described above were implemented, about half of Maine's residential customers would experience bill increases.





G. Summary of Alternatives

The following table summarizes the incentive impacts of the various alternative regulatory tools discussed in this section, as well as traditional regulation and the rate cap mechanism currently in place in Maine.

Regulatory Incentives and Incentive Mechanisms
Incentive Impacts

	Electricity Consumption	Energy Efficiency	System Reliability	Operational Efficiency	Economic Development
Traditional Regulation	Incentive to Promote	Incentive to Discourage	Possible Incentive to Over Invest	Little Incentive to Maximize	Incentive to Promote
Rate Cap Regulation	Enhanced Incentive to Promote	Enhanced Incentive to Discourage	Incentive to Minimize Investment	Enhanced Incentive to Maximize	Enhanced Incentive to Promote
Revenue Decoupling with Rate of Return	No Incentive to Promote	No Incentive to Encourage	Possible Incentive to Over Invest	Little Incentive to Maximize	Reduced Incentive to Promote
Revenue Cap Regulation	No Incentive to Promote	No Incentive to Encourage	Incentive to Minimize Investment	Enhanced Incentive to Maximize	Reduced Incentive to Promote
Fixed Rate Design	No Incentive to Promote	No Incentive to Encourage	No Impact	No Impact	No Impact
Lost Revenue Adjustments	Incentive to Promote	No Incentive to Discourage (Utility Programs)	No Impact	No Impact	No Impact
Shared Savings	Incentive to Promote	Reduced Incentive to Discourage (Utility Programs)	No Impact	No Impact	No Impact
ROE Adjustments	Reduced Incentive to Act Contrary to State Policy	Enhanced Incentive to Promote State Policy	Enhanced Incentive to Provide Appropriate Reliability	No Impact	Enhanced Incentive to Promote State Policy (e.g.., Energy Efficient Business)
Service Quality Standards	No Impact	No Impact	Enhanced Incentive to Provide Adequate Reliability	No Impact	No Impact
Direct Pass-Through	No Impact	Reduced Incentive to Discourage (Utility Programs)	Enhanced Incentive to Provide Adequate Reliability	Little Incentive to Maximize	No Impact

V. OTHER STATE MECHANISMS

The Commission has conducted a survey of other states and a literature search to determine the existence of possible mechanisms that can be used to affect or alter utility financial incentives with respect to energy efficiency and conservation and system reliability. The results of this research are presented in this section of the report and summarized in the following tables. The Commission was not able to obtain information from every state and, accordingly, the presentation in this section is based on those states for which information could be obtained.

A. Energy Efficiency and Conservation

Many states employ a variety of mechanisms to address the financial disincentive of utilities to reduce consumption through energy efficiency and/or conservation. The mechanisms most commonly used are performance incentives, shared savings, and lost revenue adjustments. Some states also employ a direct pass-through of costs and ROE adjustments. A number of states eliminated their conservation incentive mechanisms after their state restructured the electric industry or removed the obligation of utilities to pursue conservation and efficiency programs. The Commission's research revealed no state in which conservation incentive mechanisms are applied to utilities under circumstances in which utilities are not obligated to pursue efficiency and conservation programs.

A number of states adopted a revenue decoupling mechanism in the past. However, no state currently employs this type of mechanism. Decoupling mechanisms have been eliminated either due to dissatisfaction with their operation or as a result of changes in the industry structure. However, two states (California and Montana) are currently considering the re-adoption of a decoupling mechanism. A renewed effort regarding conservation incentives in these states is a result of the failure of restructuring efforts to produce effective retail competition.

Finally, the Commission is unaware of any state that has moved to a fixed charge rate design as means of addressing utility incentives regarding energy efficiency and conservation. However, New York has a pending investigation of electricity delivery rate disincentives against the promotion of energy efficiency, renewable technologies, and distributed generation.

The following table presents a summary of other state energy efficiency and conservation incentive mechanisms.

State	Revenue Decoupling	Lost Revenue Adjustment	Shared Savings	Performance Targets Incentives/ Targets	ROE Adjustments	Direct Pass-through	Mechanisms Eliminated *	Non-utility Efficiency Agency	Revenue Decoupling in Past	None
Arkansas										X
Calif.			X	X					X	
Colo.										X
Conn.				X						
Delaware										X
Florida						X			X	
Illinois										X
Indiana		X	X	X						
Iowa										X
Kansas					X					
Kentucky		X	X						X	
Mass.				X						
Minn.				X						
Missouri										X
Montana					X				X	
Nebraska										X
Nevada				X						
New Jersey		X		X						
New York							X	X	X	
Ohio							X			
Oregon							X	X	X	
Penn.										X
Rhode Island				X						
Tenn.										X
Texas										X
Utah						X			X	
Vermont							X	X		
Virginia										X
Wash.				X					X	
Wisc.			X					X		
Wyoming										X

* State had one or more efficiency mechanisms in the past. These mechanisms were eliminated after industry restructuring or when utility obligations to implement efficiency programs were removed.

B. System Reliability

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The majority of states for which the Commission was able to obtain information have no specific mechanism to address the financial incentives for utilities to provide adequate system reliability. However, service quality standards that involve financial penalties for the failure to meet pre-specified standards are common. Some states do adjust ROEs or impose monetary penalties to address service quality issues.

The following table presents a summary of other state's system reliability incentive mechanisms.

State	Service Quality Standards Penalties	Service Quality Standards Rewards	ROE Adjustments	Monetary Penalties	Direct Pass-through	None
Arkansas			X	X		
California	X					
Delaware				X		
Florida	X	X				
Indiana						X
Iowa			X			X
Kansas						X
Kentucky						X
Missouri						X
Montana						X
Nebraska						X
Nevada						X
New York	X					
Ohio						X
Pennsylvania				X		
Tennessee						X
Texas			X			
Utah						X
Vermont	X					
Virginia						X
Washington	X					
Wisconsin						X
Wyoming						X

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VI. RECOMMENDATIONS AND ALTERNATIVES

As required by the Legislature, this report covers utility incentives with respect to two distinct areas: system reliability and energy efficiency. The issues involving system reliability are relatively straightforward. The Commission's view is that, as a general matter, the current regulatory framework has produced a reasonable balance of system reliability and ratepayer cost. Accordingly, no major changes to the regulatory scheme should occur to address reliability incentives.

The issues involving energy efficiency and the promotion of electricity consumption are relatively more complex. The Legislature must consider in the first instance whether the current incentives that utilities have to promote the use of electricity raise substantial public interest concerns. The threshold question in this context is whether it is the policy of this State to discourage the consumption of electricity. If this is the policy of the State, the next consideration is whether utilities are particularly effective in promoting the use of electricity and thereby frustrating the State's ability to attain its policy goal. Finally, if both questions are answered in the affirmative, in the Commission's view the Legislature should consider whether potential changes to the regulatory structure to alter utility incentives might nevertheless create greater problems than they solve.

The Commission expresses no opinion on whether the State should adopt a policy that the consumption of electricity is against the public interest. However, as discussed in this section of the report, the Commission has serious concerns regarding the potential consequences of efforts to remove the financial incentives of utilities to promote their product through fundamental changes in regulatory structure or rate design.

A primary question is whether the current regulatory framework is subverting efforts to promote conservation and the efficient use of electricity. The Commission's view is that the current framework does not have this effect. The Commission has some limited evidence that utility efforts to promote consumption are not particularly effective. More importantly, however, the Commission's view is that conservation and energy efficiency are driven more by customer decisions than by utility action. Accordingly, it is more important that consumers have proper price signals to conserve and that the State retain a vibrant state-wide conservation program (i.e., the Commission's Efficiency Maine program) than it is to change utilities' actions.

It is for these reasons that the Commission recommends no fundamental change in the current regulatory structure to address utility financial incentives regarding the consumption of electricity. Nevertheless, in the following section, we have outlined and evaluated several alternative approaches if the Legislature decides that public policy requires that current financial incentives should be altered.

A. Recommended Regulatory Approach

The Commission recommends that no fundamental changes be made to the current regulatory structure to alter utility financial incentives.

1. Rate Cap Regulation

Multi-year rate cap plans (which have been in place for CMP since 1995) have proven to be extremely successful in satisfying their objectives. In effect, rate cap plans mirror the competitive market by providing strong incentives for utilities to increase efficiencies in their operations and lower their costs of providing service, which have the effect of keeping rates as low as possible.

Rate caps were initially adopted in Maine in response to a series of frequent, unpredictable rate increases. The overarching goal of rate cap regulation was, and continues to be, the minimization of rates and rate volatility. Maine has high electric rates relative to other states. High electricity rates and rate level unpredictability have a significant negative impact on the State's residents and businesses and on economic development. Thus, the minimization of rates and the maintenance of rate predictability and stability, in the Commission's view, are high priorities for the State's regulatory system. As discussed in Section III of this report, Maine's implementation of rate cap regulation has satisfied its primary goals.[44] Moreover, rate cap plans have improved the regulation of service reliability through the creation of systematic and objective SQIs. While such plans do act to enhance a utility's incentive to promote consumption relative to traditional regulation, the enhanced incentive is a matter of degree, in that utilities under traditional regulation always had a powerful incentive to promote sales.

The Commission recommends that multi-year rate cap plans remain the basic regulatory approach for Maine's T&D utilities' distribution delivery rates.

2. System Reliability Mechanisms

System reliability is essentially a function of the amount of money spent on facilities and maintenance. Greater reliability can always be achieved, but it would be at a cost to ratepayers. Thus, the question of the proper level of system reliability is one of balancing the reliable supply of power with cost. The Commission's view is that, as a general matter, Maine has achieved a reasonable balance of reliability and cost.[45] This does not mean that there are no problems or concerns. The Commission must remain diligent to ensure that Maine consumers have adequate and reliable electric service at a reasonable cost.

The use of service quality standards should remain the primary regulatory means to ensure adequate reliability. As discussed above, service quality standards represent a vast improvement over the traditional regulatory approach to ensuring a proper level of system reliability and providing utilities with appropriate financial incentives. The use of service quality standards allows the Commission to monitor system reliability in a more systematic and

comprehensive manner, and results in direct financial consequences if utilities fail to provide adequate service. The Commission will continue it efforts to refine the service quality standards in ways that improve their operation. Refined service quality mechanisms that the Commission may consider in future proceedings would include service area specific CAIDI and SAIFI targets, a metric which measures momentary interruptions (such as MAIFI), and a mechanism to reward superior service by expanding the earnings "dead-band" which would allow the utility to retain additional profits realized through efficiencies without penalizing ratepayers by increasing rates. In addition to service quality standards, the Commission maintains its ability, as well as its obligation, to respond to any indication (such as through customer complaints) of a reliability problem anywhere in the State by initiating investigations and ordering utilities to remedy the situation in a timely fashion.

The Commission recommends that service quality standards continue as the primary means to ensure adequate system reliability and that efforts continue to be made to improve the operation of the standards.

3. Energy Efficiency Mechanisms

As discussed above, rate cap regulation does give utilities financial incentives to promote the consumption of electricity and to discourage energy efficiency and conservation. However, Maine's T&D utilities no longer have the obligation to undertake energy efficiency and demand side management programs. The elimination of this obligation makes the incentive issue much less critical because utilities are no longer required to design and conduct programs that, if they succeed, reduce their profits. The concern under the current environment is the motivation of utilities to act contrary to the State's efficiency and conservation policies primarily through the promotion of consumption.

When Maine's utilities were under the legal obligation to pursue cost-effective conservation measures, the conflicting incentives were of paramount concern. Any system in which an entity's financial interests are contrary to its legally mandated activities is problematic. Although utilities in Maine accepted their obligations to varying degrees, the Commission was required to continually monitor utility operations to ensure that they were pursuing appropriate efficiency and conservation measures.

This situation no longer exists in Maine. Pursuant to the recently enacted Conservation Act,[46] state-wide ratepayer funded efficiency and conservation programs are now developed and implemented by the Commission and utilities properly have no role.

The current situation is that utilities, like any other business, have the incentive to promote their product. Therefore, it is not surprising that CMP actively advertises the use of electricity (e.g. air conditioning and lighting promotional advertising).[47] However, in a similar manner, oil and propane dealers promote the use of their product, and retail outlets promote the sale and use of appliances, such as air conditioners. The Commission does not view this situation as necessarily improper. As a general matter, it is appropriate for private businesses to pursue the growth of their business and profits, while government acts to promote the public interest through activities such as the sponsorship of energy efficiency and

conservation programs.[48]

As mentioned, the Commission has information suggesting that utility activity to promote the consumption of electricity has had limited effect. Through information provided by CMP in a recent Commission proceeding, it appears that CMP's air conditioning ads have had only a very modest impact on its revenues. This modest impact of utility promotional efforts must be weighed against the potential adverse impacts and unintended consequences that may result from efforts to fundamentally alter the State's current regulatory framework. The Commission believes that a better approach to supporting the State's policy in favor of energy efficiency and conservation is to maintain an effective and adequately funded state-wide program in which efforts are made to directly affect the actions and motivations of electricity consumers.

The Commission does not recommend that regulatory mechanisms be adopted to alter utilities' current incentives with respect to electricity consumption and energy efficiency.

4. Rate Design

T&D utilities' current underlying costs vary less with usage than is reflected in the current rate design. Thus, T&D utility rate design should provide for more cost recovery through fixed and demand (kW) charges relative to energy (kWh) charges. However, as illustrated in section IV of this report, a movement to a completely fixed rate design would have substantial rate impacts on a large number of the State's consumers. Customers that currently consume relatively low amounts of electricity would have substantial bill increases, while those that use a lot of electricity would experience substantial bill decreases. In addition, the adoption of a fixed rate design would significantly reduce price signals for customers to conserve and could thus promote additional consumption (although the generation portion of the bill is likely to remain usage sensitive and continue to provide some price signals for conservation). In deciding whether to go to a completely fixed rate design, the significant reduction in consumer price signals for conservation and the possible stimulus of increased consumption should be balanced against an assessment of the effectiveness of utility promotional activities.

In addition, it is not clear that a completely fixed rate design is consistent with general ratemaking principles.[49] First, T&D costs are likely to be affected by consumer usage (e.g., total demand) in that those customers that consume more electricity tend to require larger and more costly T&D facilities to serve. Moreover, an equitable design of stranded cost rates would have larger customers paying a higher amount because stranded costs (which are generation-related costs) were incurred based on customers' capacity and energy needs.

Based on principles of economic efficiency and cost causation, it is likely that the Commission will continue to move in the direction of reduced energy (kWh) charges and increased fixed and demand (kW) charges. This may occur through targeting rate decreases to energy charges as has occurred in the recent past. This approach has the benefit of moving away from T&D energy charges without increasing the bills of the State's electricity consumers. However, without specific legislative direction, a completely (or even predominantly) fixed rate

design is not likely to occur over the near term.

The Commission recommends against the adoption of a fixed charge rate design for the primary purpose of removing utility incentives to promote electricity consumption.

B. Alternative Approaches

As discussed above, the Commission does not recommend that any fundamental changes to the State's regulatory framework be made to alter T&D utility incentives. However, if the Legislature determines that mechanisms should be employed to change utility incentives with respect to energy efficiency or system reliability, this section discusses approaches that should be considered.[50]

Overall the Commission has ample statutory authority to implement the ratemaking or rate design incentive mechanisms discussed in this section. In particular, sections 3195 and 3155-A of Title 35-A provide specific authority for the Commission to adopt rate-adjustment or rate design mechanisms to promote utility operational and energy efficiency. However, as explained, the Commission is not inclined to adopt the alternative approaches discussed below without specific legislative direction.

1. Fixed Charge Rate Design

In the event the Legislature decides that some regulatory change should occur to eliminate utility financial incentives to promote electricity consumption, the Commission recommends that a legislative mandate be adopted that directs the Commission to move towards a fixed charge rate design.[51] The Commission strongly prefers this approach over fundamental changes to the regulatory framework (e.g., adoption of revenue decoupling in place of rate caps) because a "correct" rate design for T&D utilities would likely include a substantial amount of cost recovery through fixed charges and there are less likely to be unforeseen consequences.[52]

Movement to a fixed charge rate design would involve substantial bill impacts for many customers. Accordingly, the Legislature should consider mandating that the rate design change occur gradually over time (perhaps by setting annual percentage or dollar caps on bill increases).

2. Revenue Reconciliation Stranded Cost Rate-Setting

As discussed in sections II and III of this report, stranded costs have not been made the subject of incentive or rate cap regulation and are generally governed by traditional ratemaking principles. In addition, the level of stranded costs do not vary with volume and increases in sales go directly to the utility's bottom line. Therefore, current stranded cost ratemaking provides utilities with a strong incentive to promote sales.

While stranded costs do not vary with volume, many stranded cost elements are unknown at the time that stranded cost rates are set. As a result, the Commission has in

past stranded cost cases issued a number of accounting orders which have allowed the utilities to defer for future recovery any differences between the amounts allowed in rates for specific items and the actual costs of such items when incurred. While the Commission has authorized a true-up approach for specific cost items, it appears that the language of 35-A M.R.S.A. § 3208 might not permit a reconciliation of stranded cost sales.[53] This issue was discussed during CMP's last stranded cost rate setting proceeding, but was not pursued due to uncertainty concerning the Commission's authority.

Given the circumstances surrounding stranded cost ratemaking (stranded costs are not generally subject to reduction through operating efficiencies, they do not vary with volume, and a number of cost items in the past have been reconciled), it might be appropriate to reconcile stranded cost rates for variations in sales and costs projections. In the event that the Legislature desires to take steps to address incentives regarding the promotion of electricity consumption, it should consider amending 35-A M.R.S.A. § 3208 to clearly authorize the Commission to adopt a revenue reconciliation mechanism in setting stranded cost rates. If such a mechanism were adopted, a utility's incentive to increase sales would be reduced, although not eliminated, because a substantial amount of T&D costs would continue to be recovered through usage sensitive charges.

3. ROE Adjustment Mechanism

A mechanism whereby a utility's ROE is adjusted, either up or down, based on its performance in specified areas can be an effective means to impact incentives. Under such a mechanism, the Commission would predetermine a reasonable range for a utility's ROE. For example, such a range might be between 9% and 11%.[54] The Commission would then periodically review a utility's performance in certain areas to determine whether its prior activities warrant either a movement to the upper or lower end of the ROE range. The periodic review might occur on a pre-set schedule (e.g. every 2 years) or upon petition of a party. The areas of review would presumably be actions with respect to the promotion of energy efficiency and the provision of reliable service, but could include other activities.[55]

Illustrations of actions that might trigger an ROE adjustment under this mechanism follow:

-A utility violates State energy policy by using deceptive or misleading advertising to promote the inefficient use of electricity.
ROE is reduced.

-A utility acts consistent with State energy policy by acting to induce new energy efficient businesses to locate in the State.
ROE is increased.

-A utility acts to take advantage of a little-used new technology that enhances system reliability at a relatively low cost.
ROE is increased.

-A utility does not take reasonable steps to maintain sufficient reliability in a remote area of the State.
ROE is decreased.

The mechanism is subjective by its nature. The Commission would make a determination based primarily on its expert judgment. Thus, the periodic reviews, which would occur in litigated proceedings, are likely to be controversial and consume significant resources. Adjustments would likely occur rarely, only upon especially egregious or exemplary behavior.

The Commission does not favor this approach because it is inconsistent with current rate plans and implementation is likely to be extremely difficult. However, if the Legislature so mandates, an ROE adjustment mechanism could be made part of a multi-year rate plan with rate adjustments occurring as part of the annual ARP reviews.

4. Multi-Year Revenue Cap

If the Legislature determines that the State's basic regulatory structure should be changed from the current rate cap regulation to alter incentives so utilities are financially neutral to electricity sale levels, a multi-year revenue cap program for establishing distribution rates can be considered. Under a multi-year revenue cap, the utility's "allowed" revenues would be subject to an index constructed to provide the utility with the opportunity to earn reasonable returns. This means that, similar to the current rate cap plans, the index would account for inflation and a reasonable level of productivity.

This type of revenue cap mechanism, if it can be designed correctly, would continue to provide utilities with the incentive to seek operational efficiencies and to reduce their cost of service. Moreover, a revenue cap plan can be designed to minimize the shift of revenue fluctuation risks from causes other than energy efficiency measures. In particular, attempts can be made to minimize the shift of risks from changes in economic activity and weather from the utility to ratepayers. This can occur through use of economic activity and weather normalization techniques.[56] Although often controversial, weather normalization techniques are quite common in the forecasts of utility sales. However, techniques to normalize for the economy are not common and it would be extremely difficult to distinguish between sales changes related to the economy and sales changes related to efficiency measures. Although normalization techniques can help lower risk transfers, they are imprecise and would not completely prevent the transfer of risks. However, they would reduce the shift of risks to some degree and, consequently, the rate volatility that would result from revenue cap plan.

The Commission has great reluctance regarding the adoption of any type of revenue decoupling mechanism. Although the mechanism has theoretical appeal, the Commission has substantial concern over unintended consequences that may accompany the adoption of a regulatory structure which is so dependent on unpredictable events. Such unintended consequences rapidly developed with the Commission's experiment with ERAM in the early 1990s and, as discussed in section V of this report, no state currently has a revenue decoupling mechanism (although several states had adopted such mechanisms in the past). The Commission urges great caution in abandoning the current regulatory framework, which is

generally working as intended, in favor of an unproven mechanism so as to address an incentive issue that may not be of great consequence.

5. Prohibition or Regulation of Promotional Activities

If the Legislature determines that utility promotion of electricity consumption is a serious public interest problem, the most direct solution would be a legislative ban or regulation of promotional activities. Such an approach would obviously raise First Amendment issues. The Commission has not analyzed those issues, but it is conceivable that if the Legislature finds electricity consumption to be a substantial public concern (e.g., threat to public health), some restrictions on its promotion may be legally permissible.

The most direct approach would be a ban on promotional advertising. A less intrusive approach would be for all such advertising to include some type of required statement. For example, a requirement can be adopted that all electricity promotional advertising includes information on the environmental impacts of electricity consumption. Such a requirement, of course, would raise a difficult question: why should the Legislature single out electricity from other products (such as gasoline or heating oil) that also provide significant benefits while arguably damaging the environment? Without a satisfactory answer, those promoting electric consumption could reasonably claim unwarranted discrimination.

The Commission emphasizes that it does not recommend such an approach, but offers the concept if utility promotional advertising is the major concern underlying this examination of utility incentives.

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[1] P.L. 2003, ch. 219.

[2] The Commission views the terminology “security and robustness” to essentially mean “reliability” of the system, rather than protection against terrorist attacks. The Commission uses the term “reliability” throughout this report.

[3] *Inquiry into Incentives to Promote Energy Efficiency and Security of the Electric Grid,* Docket No. 2003-423 (June 18, 2003).

[4] The following entities provided input and comment during the Commission’s investigation: Public Advocate, Central Maine Power Company, Bangor Hydro-Electric Company and Maine Public Service Company.

[5] Under traditional regulation, utilities are not permitted to recover costs from ratepayers that the Commission finds to have been imprudently incurred.

[6] For purposes of this report, “fixed charge” or “fixed rate design” means a pre-set monthly charge that does not vary with customer energy (kWh) usage or total customer demand (kW).

[7] 35-A M.R.S.A. §§ 3151-3155.

[8] This would occur when the rate-of-return allowed by the regulatory commission exceeds the capital market rates and is referred to as the Averech-Johnson effect.

[9] If a utility is in financial trouble, it may defer maintenance or be unable to raise capital

for investment.

[10] This was the case as long as the utilities' rates were greater than their marginal cost of production, a cost relationship that has existed since the late 1980s.

[11] This is a consequence of the recovery of a substantial portion of utility costs through usage sensitive rates (i.e. per kilowatt-hour charges). The issue of moving towards greater use of fixed rates is discussed in sections IV and VI of this report.

[12] *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345 at 130 (Dec. 14, 1993).

[13] *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345(II) (Jan. 10, 1995).

[14]These are: CMP, Bangor Hydro-Electric Company ("BHE") and Maine Public Service Company ("MPS").

[15] The Commission, as part of the New England Conference of Public Utility Commissioners ("NECPUC"), is opposing increases in returns (which translate into increased rates) as a means to induce utilities to invest in transmission on the grounds that utilities already have the lawful obligation to maintain a reliable system and there has been no showing that higher returns are necessary to raise capital.

[16] For example, transmission is about 15% of CMP's total T&D rate.

[17] 35-A M.R.S.A. § 3208.

[18] *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger), "ARP 2000,"* Docket No. 99-666 (Nov. 16, 2000).

[19] *Bangor Hydro-Electric Company, Request for Approval of Alternative Rate Plan,* Docket No. 2001-410 (June 11, 2002).

[20] *Maine Public Service Company, Request for Approval of Alternative Rate Plan,* Docket No. 2003-085 (Sept. 3, 2003).

[21] As a consequence, the Commission considered and adopted many of the mechanisms discussed in section IV of this report to combat the utilities' inherent financial disincentive regarding efficiency and conservation. These include ROE adjustments, direct pass-throughs, revenue decoupling, shared savings, and DSM targets.

[22] P.L. 2001, ch. 624 (codified at 35-A M.R.S.A. § 3211-A).

[23] *See, Public Utilities Commission, Investigation Into Central Maine Power Company, Ratepayer Complaints,* Docket No. 92-078 (Aug. 6, 1992).

[24] Additionally, CMP's first ARP prevented a large amount of Maine Yankee shutdown costs from being recovered from ratepayers.

[25] Interestingly, Maine was one of the few Northeastern states which was not part of the seminal 1965 blackout. Oral history has it that the Maine operator was able to isolate Maine from the rest of region quickly enough to avoid a major blackout.

[26] In the context of reviewing BHE's SQI, the Commission has also requested such data from BHE.

[27] The task force includes Commission staff members, the Public Advocate, and representatives of CMP, BHE and MPS.

[28] MAIFI is a measure of the number of momentary interruptions on an electric utility system. These events may occur as a precursor to a sustained interruption (which is captured in the other indices) or may be isolated events that are resolved by the automatic operation of resoling devices or other protection devices on the system. MAIFI is calculated by dividing the total number of customer momentary interruptions by the total number of customers served.

[29] *Mid-Period Review Investigation of CMP's ARP 2000 Service Quality Indices,* Docket No. 2002-445 (Dec. 12, 2003).

[30] It should also be noted that, in addition to service quality standards, the Commission continues to monitor the performance of utilities with respect to system reliability. For example, after an ice storm in 2002, the Commission initiated an investigation of the resulting power outages and adopted numerous measures to improve utility response to storm and other emergency situations. *Investigation into the Adequacy of Utility Services in Maine During Power Outages,* Docket No. 2002-151.

[31] *Investigation of Central Maine Power Company's Stranded Cost Rates and Request for an Accounting Order,* Docket No. 2002-770 (June 20, 2003).

[32] *Investigation of Rate Design of Transmission and Distribution,* Docket No. 2001-245.

[33] The opposition came primarily from the Public Advocate and the Natural Resources Counsel of Maine. In recent comments provided to the Commission during its incentives investigation, the Public Advocate indicated that he is not opposed to a fixed charge rate design in concept, but believes that the resulting bill impacts for low use customers would be "entirely unacceptable."

[34] Rate decreases were also targeted to winter charges in an effort to reduce the seasonal differentiation.

[35] The implementation of revenue decoupling would have no significant impact on utility financial incentives to provide adequate system reliability relative to traditional or rate cap regulation.

[36] Mechanisms to provide utilities with positive incentives to promote energy efficiency and conservation are discussed below.

[37] *Investigation of Chapter 382 Filing of Central Maine Power Company, Order,* Docket No. 90-085 (May 7, 1991). As discussed, because a revenue cap alone does not provide a positive incentive for a utility to pursue conservation, the Commission also adopted a shared savings program in which CMP would be reimbursed for a portion of the savings from its conservation programs. Such shared savings programs are discussed below.

[38] P*roposed Increase in Rates, Order Granting Motion to Withdraw Proceeding,* Docket No. 91-174 (Jan. 10, 1992).

[39] *Consideration of Issues Concerning ERAM-Per-Customer for Central Maine Power Company, Order Approving Stipulation,* Docket No. 90-085-A (February 5, 1993). After the termination of ERAM, the Commission's efforts regarding incentive regulation moved to the development of rate cap regulation.

[40] Lost revenue adjustments are often criticized in that they create an incentive for utilities to make it appear that their programs are saving energy, when they are actually ineffective. This results in a windfall through the reimbursement of lost revenues that were never

in fact lost.

[41] The Commission has used ROE adjustments in the past to both reward and penalize utilities.

[42] For many years, utilities were allowed a direct pass-through of their fuel costs (primarily oil) pursuant to this rationale. This practice came to end for CMP with the adoption of the 1995 ARP.

[43] The recovery of a greater portion of costs through fixed charges would also reduce a utility's risk exposure which should lower its cost of capital.

[44] The Commission notes that some of the success of rate plans in minimizing rates and maintaining stability is attributable to several years of relatively low inflation.

[45] The Public Advocate has expressed a similar opinion in comments provided in this investigation.

[46] As mentioned above, the Conservation Act transferred to the Commission the responsibilities to develop and implement state-wide efficiency and conservation programs. That Act provides the Commission with ample authority to support energy efficiency initiatives in the State (within statutory funding constraints).

[47] Pursuant to Commission rule (Chapter 83), utilities are prohibited from recovering the costs of promotional activities from ratepayers.

[48] Electricity production is generally viewed as having significant environmental impacts. (For example, NEPOOL has calculated the 2001 regional average emission rates as: SO_2 – 4.9 lbs/mWh, NO_x – 1.7 lbs/mWh, and CO_2 – 1394 lbs/mWh). Potential environmental impacts and their effect on the State and its residents are appropriate grounds for government intervention to increase energy efficiency.

[49] Substantial analyses of the cost structures of Maine's T&D utilities would be required before any determination of a "correct" rate design could be made.

[50] Some mechanisms used in other states would be questionable at best in Maine where T&D utilities have no obligation to implement conservation programs. These include lost revenue adjustments and shared savings programs. It appears improper to reimburse utilities for lost sales or to reward them with a percentage of savings with respect to efficiency programs that have nothing to do with utility activities.

[51] As a general matter, the Commission's view is that specific rate design determinations should be made by the Commission pursuant to general ratemaking principles. The suggestion that the Legislature mandate a particular rate design is made only in the context of a legislative decision that utility financial incentives to promote the consumption of electricity be removed. In that a case, a legislative mandate regarding a specific rate design would be appropriate.

[52] A completely fixed rate design would result in a significant reduction of financial risk for utilities. Accordingly, a movement towards fixed rates should be accompanied by a review of utilities' cost of capital used for ratemaking purposes.

[53] 35-A M.R.S.A. § 3208(6) provides: "When correcting stranded cost estimates and adjusting stranded cost charges, the Commission shall make any change effective only

prospectively and may not reconcile past estimates to reflect actual values.

[54] An ROE range of 200 basis points should be large enough to get a utility's attention. For example, a reduction of 100 basis points for CMP would amount to a revenue loss in the range of $7 million.

[55] Direct pass through of costs can also be used in conjunction with ROE adjustments. For example, if a utility makes an investment in cost-effective new technologies that results in enhanced system reliability, it can be allowed to defer the expense for dollar-for-dollar recovery.

[56] For example, normalization techniques might seek to estimate that each additional degree day results in X amount of additional electricity sales or that a percentage increase in the gross state product results in Y amount of additional sales.

Special Comment

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Impact Of Conservation On Gas Margins And Financial Stability In The Gas LDC Sector

Summary Opinion

- Moody's surveyed its 34 gas LDCs (local distribution companies) as to the impact of customer conservation on their volumes of consumption and gross margins and found that 18 could quantify the loss in per customer volume consumption.
- Only four of the 18 LDCs had ratemaking mechanisms in place to recover on a regular basis the lost margins due to conservation.
- Upon closer examination of certain gas utilities, it appears that customer gas consumption patterns are more responsive to changes in gas prices (price elasticity) than to any other single factor.
- Conservation is an important part in balancing the national gas supply and demand equation but under traditional regulatory frameworks in many states, few gas utilities have the incentive to actively encourage gas conservation and promote education in gas usage efficiencies among their customers.
- With the likelihood that gas prices will remain high and volatile, conservation is expected to become a more formidable force in influencing gas consumption in the residential and commercial customer segments going forward.
- Utility commissioners in various states differ as to their approach in allowing their gas utilities to recover lost margins on account of consumption variations resulting from conservation. Those commissions with the more supportive regulatory frameworks, tend to allow mechanisms for recoveries of revenues lost to conservation and have utilities with stronger financial profiles.
- More LDCs are becoming aware of the conservation factor and the impact that this has on their customers' gas usage and the utilities' profitability, and are considering applying for the appropriate rate design changes.
- Moody's believes that having utility rate designs that compensate the gas LDCs for margin losses caused by variations in gas consumption due to conservation as with variations due to weather, would serve to stabilize the utility's credit metrics and credit ratings. Utilities having these ratemaking mechanisms also tend to carry "A" credit ratings.

Introduction

The rising impact of conservation in determining customer gas consumption levels has been more insidious than other more noticeable variables, such as those caused by weather (see Moody's October 2002 Special Comment titled *Negative Rating Trend For Local Gas Distribution Companies: Impact of Diversification And Warm Weather*). It is curious however, how some state utility commissions recognized the potential impact of customer conservation on gas utility gross margins much earlier than other states, and made special provisions in their regulatory framework to accommodate for this variable. Perhaps some states are more attuned to the benefits of environmental conservation, have better regulatory support from their utility commissions or their customers are more cognizant of the need for compensating their utilities for their fixed costs. Whatever the reasons, it is clear that in some states the factor of conservation is fully understood and accepted into the gas utility rate-setting regime while in others the educational process is slower and more difficult due to historical differences between the utility on the one hand vs. public advocates and utility commission staff on the other, often viewing each other as traditional adversaries operating in a *zero-sum* environment.

What is noteworthy, is that with the growing awareness that natural gas supplies are becoming increasingly limited and that gas prices have been increasing in price and volatility in recent years, more LDCs are searching for reference points which might serve to yield them potential solutions to their problems of variable, and oftentimes, unpredictable customer consumption. If a utility's state commission is not sympathetic to the issue, the utility could draw examples from neighboring state commissions or reach across the country to other states, where the recognition of conservation and its impact on ratemaking mechanisms could have some relevant practical experiences that might be applicable to the utility's own regulatory jurisdiction. This is what appears to be happening as more gas LDCs confront a common issue that is only now rising to the level of national awareness.

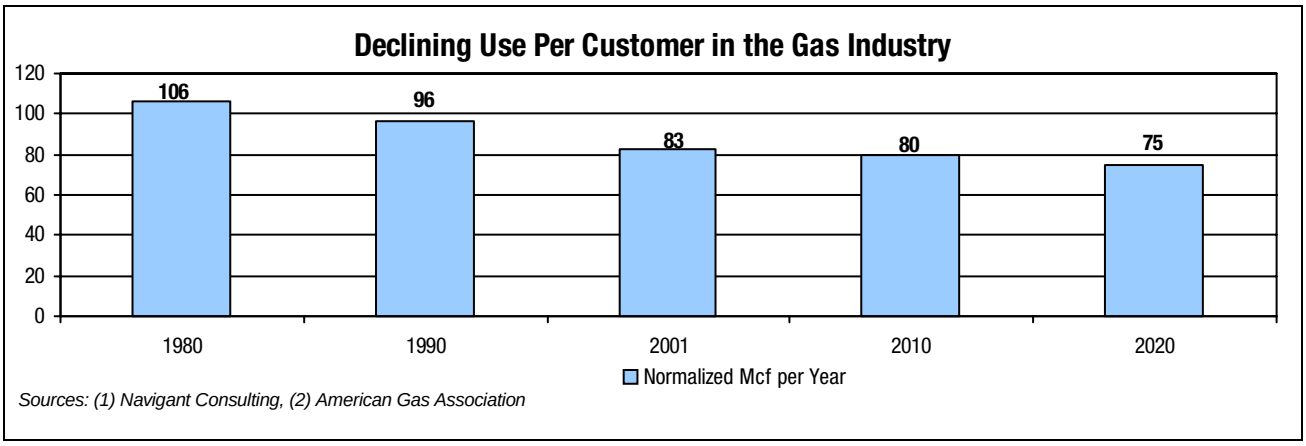
Also, as more LDCs and utility commissioners speak with one another, a greater appreciation for some of the forces affecting this segment of the energy industry develops and rate designs or the mechanisms for dealing with common issues become more accepted and might eventually become the norm. It is interesting to observe that an element of *cross-pollination* appears to be taking place where companies have become more willing to share their ideas and experiences with one another and state commissioners through the National Association of Regulatory Utility Commissioners (NARUC) are becoming more open to new approaches in dealing with their own regulatory issues in a land dominated by a *patch-work* of 50 independent state regulations. Nevertheless, the utilities that have established the appropriate ratemaking mechanisms in place first are usually the ones that fare the best in terms of financial earnings stability and credit strength, a status that appears to have been consciously achieved in cooperation with their regulators rather than being merely fortuitous or coincidental.

Conservation and Traditional Utility Rate Structures

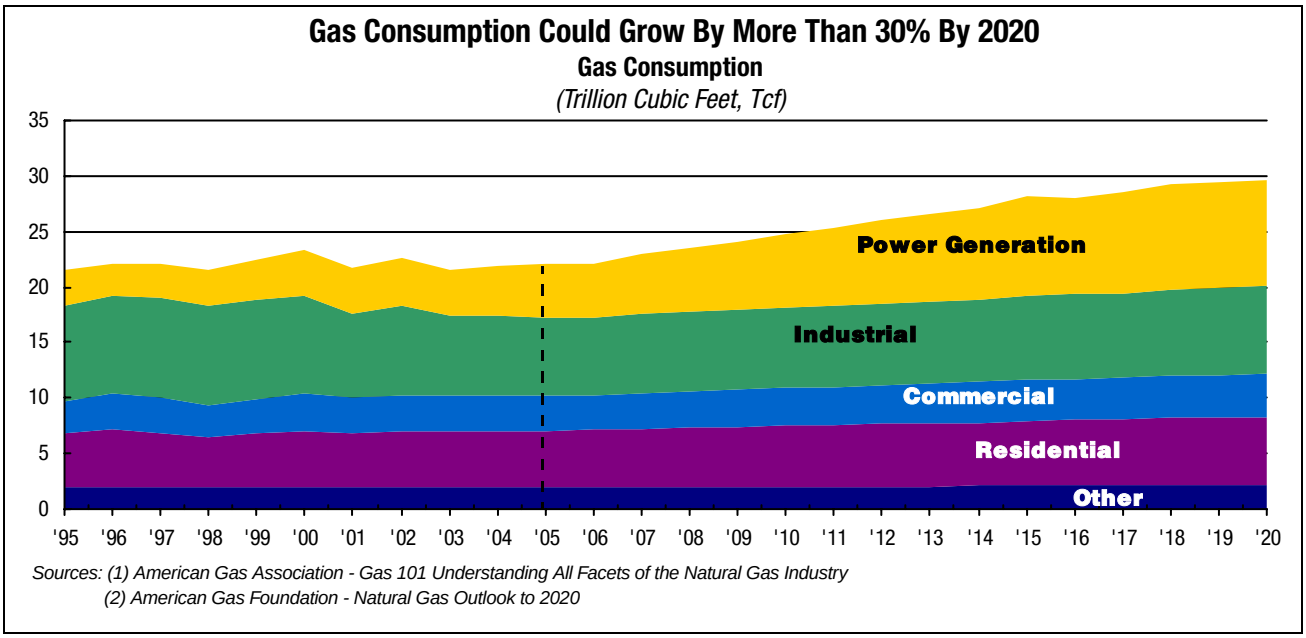
Moody's defines "conservation" as any technical advancement that improves home heating or the gas appliance efficiencies as well as the curtailment of consumption on account of high gas commodity prices. With this in mind, we surveyed our portfolio of 34 gas LDCs to inquire as to the possible impact that conservation might have on their customer gas consumption (primarily residential, as they comprise the largest class of firm customers for most LDCs compared with commercial or industrial customers, with the latter often subject to interruptible service) and the effect on their gas margins. Of the 34 LDCs, 18 were able to quantify the effect on their gas volumes and all 18 showed varying declining amounts and percentages in per customer consumption. However, only four had ratemaking mechanisms in place to recover these lost margins. The declines in per customer volumetric gas consumption ranged from 6% to 22% over a ten year period depending on the individual state. Interestingly, declines occurred whether LDCs were urban or rural[1], slow growing or rapidly growing.

The trend of declining use per customer in the gas industry also appears to be supported by a study done by the American Gas Association (AGA) released in September of 2004, as depicted in the following graph. This study suggests that the declining consumption trend is likely to continue for several more years, although our research indicates that some companies are more affected than others.

1. *Moody's defines urban as any city or town that is served by the LDC's main gas line in a contiguous flow of proximity for 100,000 or more customers. Any number less is considered rural.*



Interestingly enough, in his keynote address in January 2005, Laurence M. Downes, Chairman of the American Gas Association, stated that continued energy efficiency is an important factor in helping balance the limited accessible supply of natural gas in the United States along with the rise in gas demand on the part of electric power generators, industrial and commercial users and the need for increased housing in the country.[2]



However, in the July 2004 Joint Statement made by the AGA and the National Resources Defense Council (NRDC), a nationally recognized environmental group based in San Francisco, admission is made to a fundamental flaw in the way gas utility rates are traditionally structured in many states: namely, that the high fixed costs of operating a gas distribution system are only fully recovered when customers consume the gas volumes upon which their traditional rates are designed. If there is little or no consumption, the LDC is unable to recover its costs. Under this scenario, gas companies have no desire to encourage energy conservation or promote gas efficiency education among consumers. This conflict is stated more succinctly by Jon Stoltz, Senior Vice President of Regulatory and Gas Supply at Cascade Natural Gas Corporation in Seattle, Washington, when he said, "Our financial responsibilities and corporate citizenship responsibilities are at odds. The utility is forced to choose between conservation and profitability."[3]

One solution proposed by the Joint Statement of the AGA and the NRDC requested the National Association of Regulatory Utility Commissioners to consider and support any mechanism that uses automatic rate true-ups to ensure

2. *Investment Outlook for the Natural Gas Industry,* presented by Laurence M. Downes before the New York Society of Security Analysts, January 27, 2005, slide 7, "Continued Energy Efficiency is Important."
3. "Decoupling Through A Payment Stabilization Mechanism," White Paper by John Stoltz, April 21, 2005, p.1

that a utility's recovery of authorized fixed costs are not dependent on variations in gas sales. These ratemaking mechanisms are sometimes referred to as "decoupling," "conservation tariffs" or "conservation margin trackers."

We should note that this conservation problem is particular to the gas and not the electric power industry sector, where average kilowatt-hour of usage per customer has been generally rising over time. This may necessitate some careful explanations with regulators as they attempt to understand some of the differences between the gas and the electric power sectors.

In an attempt to better appreciate some of the decoupling mechanisms currently in use, Moody's considered three examples of how gas utilities were dealing with the impact of conservation. The first example is that of Southwest Gas Corporation (Baa2 senior unsecured, negative outlook) based in Las Vegas, Nevada; the second, Northwest Natural Gas Company (A3 senior unsecured, stable outlook) based in Portland, Oregon; the third, Southern California Gas Company (A2 senior unsecured, stable outlook) based in Los Angeles, California.

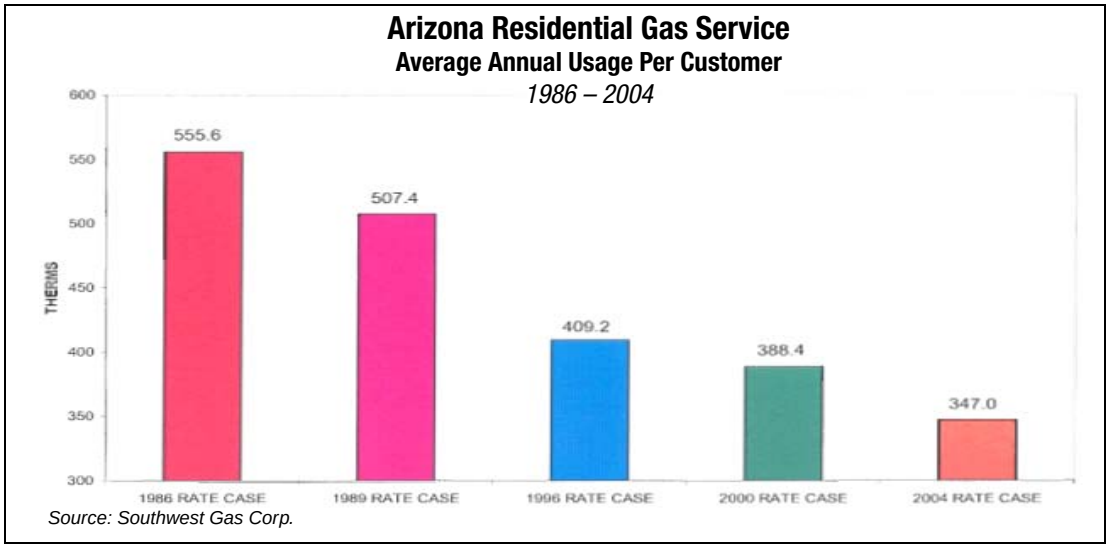
Southwest Gas Corporation

In February of 2004, Moody's changed the outlook on Southwest Gas Corporation to "negative" from "stable." The company was already one of the fastest growing LDCs in the country with a customer base expanding at the rate of 5.4%p.a. According to their CEO, Jeffrey W. Shaw, the company was growing at the equivalent rate of one gas LDC each year. This rapid growth has resulted in regulatory lag, as capital expenditure cost recoveries could not keep up with up-front growth expenditures and led to increased financial leverage.

In addition, the company had announced that 2003 earnings were lower on account of warmer than normal weather for two consecutive years with 2003 being one of the warmest in over 100 years. All these factors impacted the company at a time when it had no conservation margin trackers or weather normalization mechanisms in place. Subsequently, it was able to gain a conservation margin tracker in California, but this only covered about 10% of its service territory, leaving the remaining 90% of gas margins exposed to variable gas consumption.

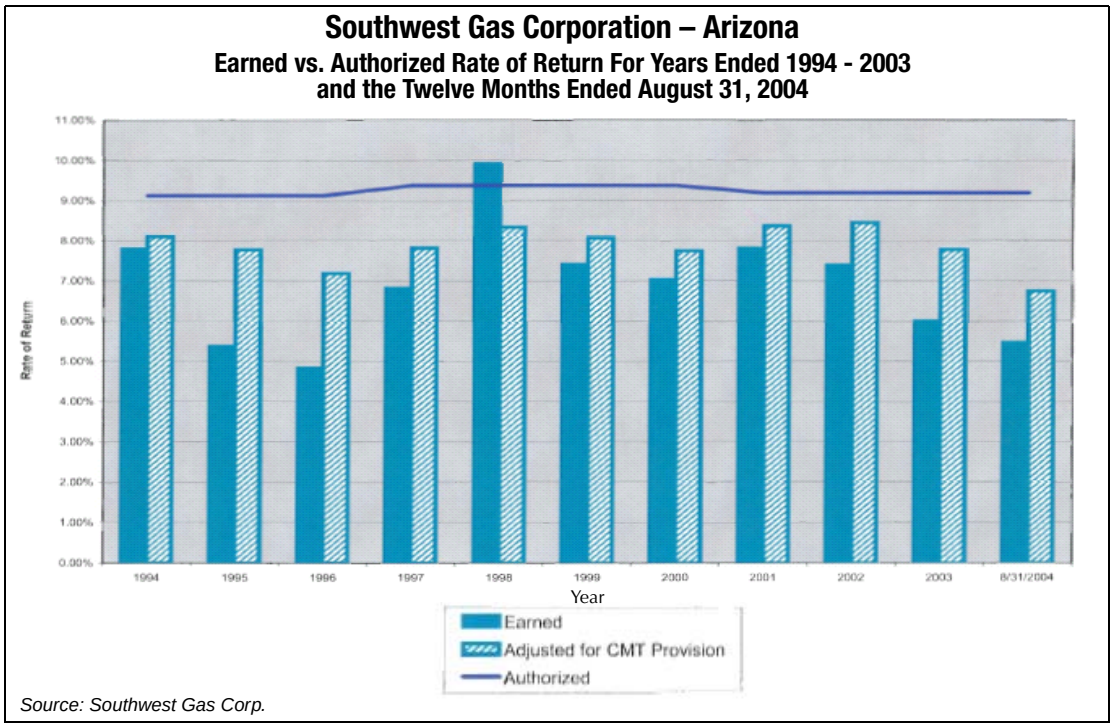
In December of 2004, Southwest Gas decided to file a new rate case in Arizona which accounts for about 55% of its gas margins. In this rate case, a new rate design was introduced in Arizona for the first time in the form of a conservation margin tracker that would capture declining gas volumes on account of both conservation and weather variables when compared against a baseline consumption level.

The mechanics of this rate design appear to be straightforward. The company first establishes a revenue requirement that would cover all costs of systems operation (excluding gas commodity costs), and then it apportions this number among the residential class of customers by dividing by the total volume of gas sold to each residential customer. As new customers are added onto the gas distribution system, they also help absorb the costs of operation.



The first graph for Southwest Gas shows a steady 37.5% decline in annual per customer usage of gas over 18 years, or 2.1% p.a., with the consumption data weather-normalized. What is noteworthy is that despite the rapid growth in customer base in Arizona (Phoenix being one of the fastest growing cities in the country), per customer consumption is still falling.

The second graph for Southwest Gas demonstrates an inability to earn its authorized rate of return in Arizona (as depicted by the solid bars), which lie below the approximately 9%authorized overall rates of return (depicted by the horizontal line near the top), equivalent to an 11% return on equity. The gap is closed somewhat by the addition of a new conservation margin tracker (CMT) as proposed by the company in its new rate case for Arizona, but even then it falls short of earning the full authorized rate of return, a shortfall that needs to be met by other means such as exercising tighter standards when considering new expansions into more remote desert areas of the state. The spike in realized earnings in 1998 represents an unusual year when winter weather was 27% colder than normal, a windfall which the company is willing to forgo in exchange for more stable earnings over time.



Source: Southwest Gas Corp.

In its Arizona rate filing, Southwest Gas also anticipates the support of the Southwest Energy Efficiency Project (SWEEP), a regional environmental group promoting energy efficiency in the southwestern states including in Arizona. Environmental groups such as SWEEP add an independent voice in support of energy conservation and they seem to acknowledge the need for gas utilities to obtain a fair rate of return on their investments in order to accomplish their environmental objectives.

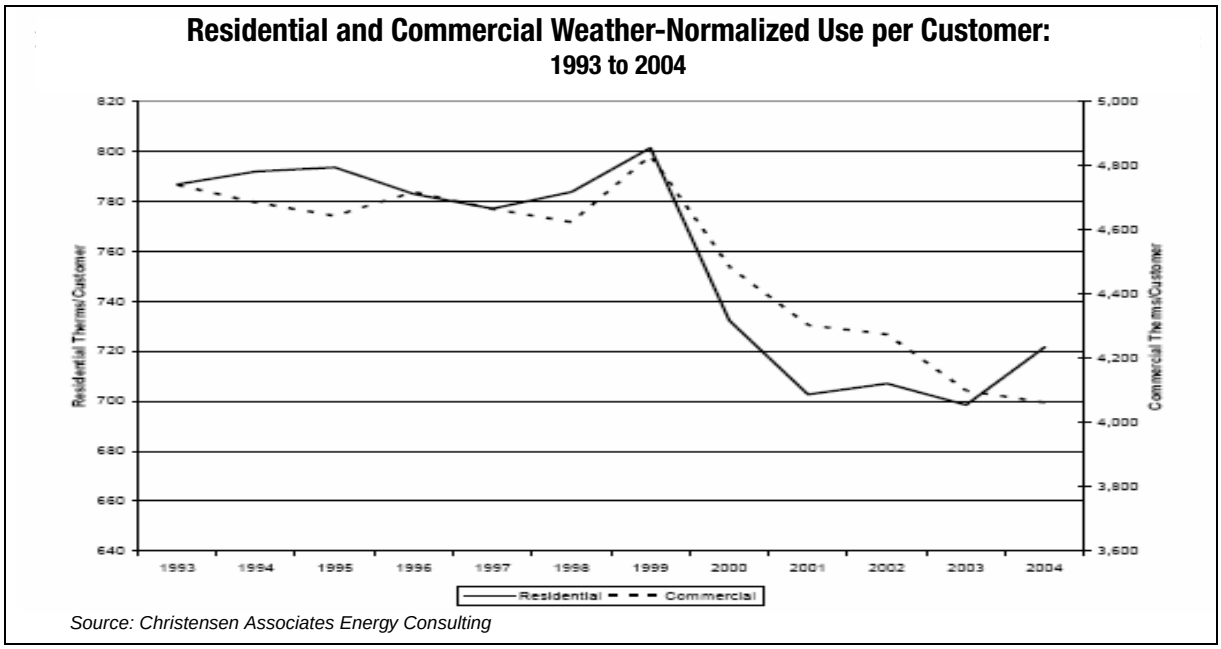
Northwest Natural Gas Company

Northwest Natural had applied for a full decoupling mechanism covering both conservation and weather factors but only obtained a conservation tariff or Distribution Margin Normalization (DMN) from the Oregon Public Utility Commission (PUC) in 2002. Its conservation tariff was granted for a limited period of three years and expires in September of 2005. In 2003, the company applied for and obtained a separate five-year weather normalization clause that operates independently of the DMN. As a condition for its DMN renewal, Northwest Natural was required to have an independent study done to determine the relative success of the rate design, and this task fell upon Christensen Associates Energy Consulting, from whom we obtained certain charts for this report.

The DMN has two essential components, 1) a price elasticity adjustment to a predetermined baseline of consumption and 2) a deferral account that captures 90% of the month-to-month deviations between actual and expected volumes. The deferred amounts are treated as adjustments to be refunded or collected in the following year.

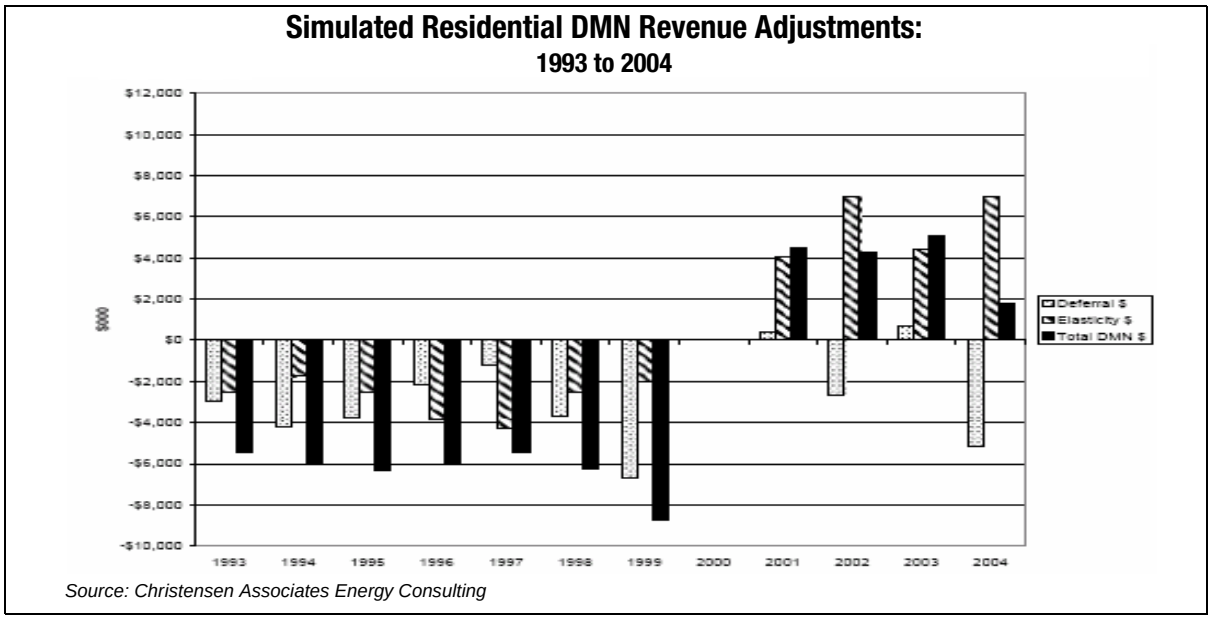
The result is that Northwest Natural's conservation tariff was able to realize an additional $3.5 million in 2003 gross margins and another $1 million in 2004 gross margins. The company also received the endorsement of the NRDC in its rate design application, which served as an independent advocate for the rate design mechanism in support for its conservation tariff application.

In the first chart for Northwest Natural, we note that both residential and commercial usage per customer were fairly constant over the 1990's when they take a sudden and sharp decline in 1999 through 2001, following a much publicized rise in natural gas prices. The slight recovery in late 2003 on the part of residential customers is due to a temporary period of declining gas prices. This chart demonstrates how in the case of Northwest Natural, customer usage is inversely correlated with changes in gas prices.



Source: Christensen Associates Energy Consulting

The second chart for Northwest Natural shows a simulated run using 2000 as a base year for the DMN, with bars above the "zero" line representing collections made by the company for conservation adjustments and bars falling below the "zero" line representing amounts to be refunded to customers. Focusing on the right side of the graph during the years when the DMN was in effect, we note that the price elasticity component represented by the cross-hatch bars are a more significant factor in the adjustment mechanism than the gray-shaded bars representing the deferral component of the DMN.



Source: Christensen Associates Energy Consulting

Southern California Gas Company

SoCal Gas is by far the largest pure gas LDC in our portfolio of 34. It also operates in a state that has one of the most progressive and supportive gas utility regulatory frameworks in the country. For example, unlike most states, California allows the use of monthly purchase gas adjustments (PGA) using short-term forecasted gas prices. When considering utility rate applications from its gas utilities, it applies a 12 month forward test period for cost recoveries, thereby helping to reduce regulatory lag. Finally, it has for many years supported the use of 100% gas balancing accounts, whereby gas LDCs are able to recover in gross margins what they lose on account of weather, conservation or other variables affecting customer use of natural gas.

In January of each year, SoCalGas sets out to recover all costs allowed by the California PUC during that year, plus any under collections or over collections of revenues from the previous year.

The total revenue requirement is divided by the forecast of sales by customer class during the year. Actual revenues are tracked against authorized revenues in balancing accounts during the year. At the end of the year, the under or over collection of revenues due to conservation, weather variation, or other conditions are then added to the subsequent year's revenue requirement to set new rates for the following year. The result is that gas sales variations do not affect net profitability of the utility.

A sample schedule of SocalGas' balancing accounts for the year 2004 appears in the table below. Note that the company finds itself with an undercollection status for 2004 of about $42 million in the lower right bottom column. This sum requires a 3% increase in system total rates for 2005.

SoCal Gas Present and Proposed Regulatory Account Balances (M$)

Account Name	4/01/04 Amortization			Proposed 01/01/05 Amortization			Proposed Change		
	Core	Noncore	Total System	Core	Noncore	Total System	Core	Noncore	Total System
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1. Affiliate Transfer Fee Memorandum Account (ATFA)	(47)	(6)	(53)	0	0	0	47	6	53
2. Aliso/Goleta Tracking Account (AGTA)	0	23	23	0	107	107	0	84	84
3. Brokerage Fee Account (BFA)	0	5	5	0	131	131	0	126	126
4. Catastrophic Event Memorandum Account (Northridge)	(1)	(0)	(1)	0	0	0		0	1
5. Core Fixed Cost Account (CFCA) [2]	(70,929)	0	(70,929)	(58,869)	0	(58,869)	12,060	0	12,060
6. Economic Practicality Shortfall Memorandum Account (EPSMA)	0	(13)	(13)	0	187	187	0	199	199
7. El Paso Settlement Proceeds Memo Acct (EPSPMA)	0	0	0	(218)	0	(218)	(218)	0	(218
8. El Paso Turned-Back Capacity Bal Acct (EPTCBA)	4,111	7,374	11,486	6,049	10,850	16,900	1,938	3,476	5,414
9. Enhanced Oil Recovery Account (EORA)	7,562	771	8,333	9,005	918	9,922	1,442	147	1,589
10. Hazardous Substance Cost-Recovery Account (HSCRA)	4,271	7,661	11,932	4,609	8,267	12,877	338	607	945
11. Interstate Transition Cost Surcharge Account (ITCSA)	0	(13,666)	(13,666)	0	18,667	18,667	0	32,332	32,332
12. Intervenor Award Memorandum Account (IAMA)	88	157	245	12	21	32	(76)	(137)	(213
13. Montebello True-Up Tracking Account (MTTA)	18,554	7,952	26,506	0	0	0	(18,554)	(7,952)	(26,506
14. Natural Gas Vehicle Account (NGVA)	(714)	(979)	(1,693)	(2,026)	(2,776)	(4,802)	(1,312)	(1,798)	(3,109
15. Noncore Fixed Cost Account (NFCA)	0	17,007	17,007	0	18,621	18,621	0	1,614	1,614
16. Noncore Fixed Costs Tracking Account (CCSI subaccount)	0	(7)	(7)	0	(95)	(95)	0	(88)	(88
17. Noncore Fixed Costs Tracking Account (MPO subaccount)	0	(1)	(1)	0	0	0	0	1	1
18. Noncore Storage Balancing Account (NSBA)	200	359	559	102	183	285	(98)	(176)	(274
19. PITCO/POPCO Transition Cost Account (PPTCA)	(217)	(389)	(606)	(518)	(929)	(1,447)	(301)	(540)	(841
20. Post-Retirement Benefits Other Than Pensions (PBOPS)	(20,410)	(2,555)	(22,965)	(10)	(1)	(11)	20,400	2,554	22,954
21. Research, Development & Demonstration Expense Account (RDDEA)	(0)	(0)	(0)	0	0	0	0	0	0
22. Reseach Royalty Memorandum Account (RRMA)	(22)	(3)	(24)	(44)	(5)	(49)	(22)	(3)	(25
23. Self-Generation Program Balancing Account (SGPBA)	6,807	12,208	19,015	4,375	7,847	12,222	(2,432)	(4,361)	(6,793
24. Wheeler Ridge Firm Access Charge Memorandum Account (WRFACMA)	(3,062)	(383)	(3,446)	(855)	(107)	(962)	2,207	276	2,484
25. **Balancing Account Subtotal**	(53,809)	35,517	(18,292)	(38,387)	61,884	23,497	15,422	26,367	41,789

Notes:

1. Balances shown include franchise fees and uncollectibles expenses.

2. Includes the Baseline Memorandum Account (BMA)

Source: Southern California Gas Company

The advantage of this procedure is that it is automatic and tends to work like "clockwork." In the absence of protest, after 40 days of presenting its annual Advising Letter of the status of its balancing accounts to the California Public Utility Commission, the adjusted rates go into effect. SoCalGas has been successfully using this methodology for margin recovery for over 20 years.

Another LDC that has a similar balancing account mechanism in place for gas system cost recovery is Alabama Gas Corporation (Alagasco, A1 senior unsecured, stable outlook). Alagasco's "rate stabilization and equalization" enables the utility to earn each year within a band of its allowed rates of return in the range of 13% return on equity. This formulaic approach that has been in place in Alabama for over 20 years is just only now being adopted in states such as South Carolina.

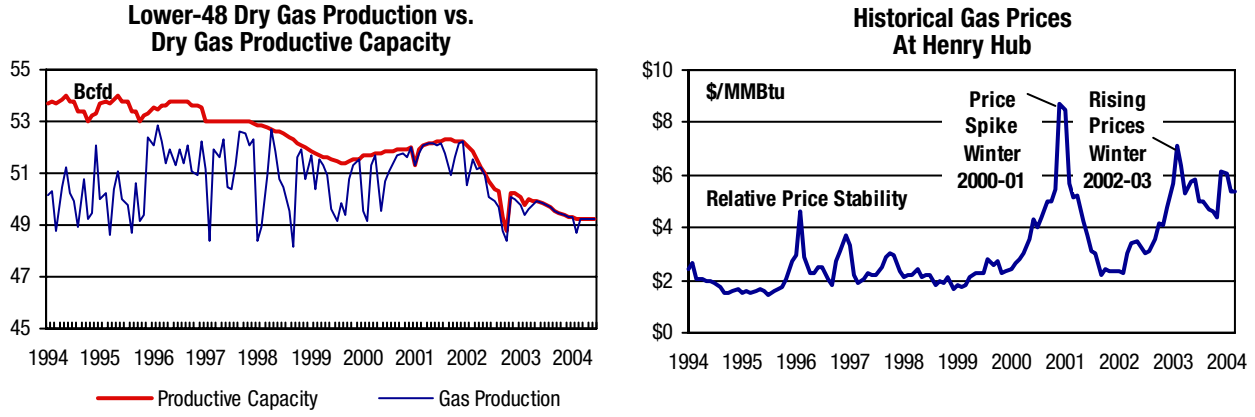
Conclusion

While declining per customer usage of gas has been occurring for many years in many parts of the country, only a handful of the 34 LDCs in our gas portfolio have ratemaking mechanisms in place to recover the utility's fixed costs on a consistent and comprehensive basis. These companies also tend to carry "A" credit ratings.

In reviewing our three examples, we observe that these mechanisms were achieved through careful coordination with interveners and with the support of environmental groups.

We expect that the decline in per customer gas usage at the residential and commercial level is a national phenomenon that is likely to persist as gas becomes more expensive and demand outstrips available supply. The charts below from the AGA and the Energy and Environmental Analysis suggests that beginning in late 1999 gas prices have become decidedly more volatile and show a generally rising trend. As noted in the case of Northwest Natural, customers are more likely to curtail their gas usage under conditions of rising gas prices.

Tightening Demand And Supply Curves = Price Volatility



Sources: (1) American Gas Association -Gas 101 Understanding All Facets of the Natural Gas Industry, (2) Energy and Environmental Analysis (EEA)

In coming months, we anticipate that more gas LDCs will be applying for these decoupling mechanisms either as stand-alone conservation tariffs as done by NWNatural or as part of an overall balancing account approach as done by SoCalGas, taking both conservation and weather factors into consideration. Companies that have announced their intention or are in the process of applying for these new ratemaking mechanisms include Cascade Natural Gas in Washington State, Piedmont Natural Gas in North Carolina and Washington Gas Light in their Maryland jurisdiction.

Finally, Moody's believes that having utility rate designs that compensate the gas LDCs for margins lost on account of variations in conservation as with variations in weather, would serve to stabilize a utility's credit metrics and credit ratings.

Related Research

Special Comments

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 #87301

Negative Rating Trend For Local Gas Companies: Impact of Diversification And Warm Weather, October 2002, #76344

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Special Acknowledgements

Moody's would like to extend special thanks to Southwest Gas Corporation, Northwest Natural Company, Southern California Gas Company, Alabama Gas Corporation, Cascade Natural Gas Corporation, Piedmont Natural Gas Company, Washington Gas Light Company and many other gas companies that have gone unmentioned in this study for sharing their findings, experience and materials that enabled our completion of this special comment. We would also like to thank the American Gas Association, Navigant Consulting, Christensen Associates Energy Consulting, American Gas Foundation, Energy and Environmental Analysis for allowing the use of their materials, which have been of great assistance in helping illustrate the commentary.

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Report Number: 92787

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Re Delmarva Power & Light Company
PSC Docket No. 06-284
Order No. 7152

Delaware Public Service Commission
March 20, 2007

Before McRae, chair and Conaway, Lester, Winslow, and Clark, commissioners.

BY THE COMMISSION:

*1 AND NOW, this 20th day of March, 2007;

WHEREAS, the Commission has received and considered the Findings and Recommendations of the Hearing Examiner ('Report') issued in the above-captioned docket, which was submitted after a duly noticed public evidentiary hearing;

AND WHEREAS, the Hearing Examiner recommends that the Proposed Settlement Agreement, dated February 15, 2007, which is endorsed by all the parties, and which is attached to the original hereto as 'Attachment B,' be approved;

AND WHEREAS, the Proposed Settlement Agreement reflects a total base rate revenue increase of $9 million, or approximately 3.9 percent of total gas revenues, based on an overall rate of return of 7.73 percent and a return on equity of 10.25 percent;

AND WHEREAS, under the terms of the Proposed Settlement Agreement, a generic statewide proceeding will be initiated for the purpose of investigating 'decoupling' mechanisms for gas and electric distribution utilities;

AND WHEREAS, the Commission finds that the proposed rates and tariff changes are just and reasonable and that adoption of the Proposed Settlement Agreement is in the public interest;

Now, therefore, IT IS ORDERED:

1. That, by and in accordance with the affirmative vote of a majority of the Commissioners, the Commission hereby adopts the March 15, 2007 Findings and Recommendations of the Hearing Examiner, appended hereto as 'Attachment A.'

2. That the Commission approves the tariff changes and rates contained within the Proposed Settlement Agreement, which is attached to the original hereto as 'Attachment B,' effective for natural gas service rendered on and after April 1, 2007.

3. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

ATTACHMENT 'A'

FINDINGS AND RECOMMENDATIONS OF THE HEARING EXAMINER

William F. O'Brien, duly appointed Hearing Examiner in this Docket pursuant to 26 Del. C. § 502 and 29 Del. C. ch. 101, by Commission Order No. 7041, dated October 3, 2006, reports to the Commission as follows:

I. APPEARANCES

On behalf of the Applicant, Delmarva Power & Light Company: ANTHONY WILSON, ESQUIRE.

On behalf of the Public Service Commission Staff: ASHBY & GEDDES BY: REGINA A. IORII, ESQUIRE.

On behalf of the Division of the Public Advocate: G. ARTHUR PADMORE, PUBLIC ADVOCATE.

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II. BACKGROUND

1. On August 31, 2006, Delmarva Power & Light Company ('Delmarva Power' or the 'Company') filed an application with the Delaware Public Service Commission ('Commission') seeking approval for an overall increase in natural gas base (delivery) rates of $14,967,000, or approximately 6.62 percent over currently approved rates. The Application also included proposed modifications to the Company's gas tariff relating to 'Reconnect' and 'Premise Collection' fees and a new Bill Stabilization Adjustment ('BSA') mechanism. The BSA, if approved, would allow the Company to adjust its base (delivery) rates to reflect actual changes to the revenue it collects on a per customer basis, thereby 'decoupling' revenues from sales.

2. On October 3, 2006, the Commission entered PSC Order No. 7041 suspending the rates proposed in the Application and appointing a Hearing Examiner and Rate Counsel to process the docket. On October 12, 2006, Delmarva Power filed with the Commission revised tariff leaves designed to increase its gas rates by $2,500,000 annually, which it is permitted to do under 26 Del. C. §306(c) (authorizing an interim rate increase of up to $2.5 million annually or 15 percent, whichever is less). On October 17, 2006, the Commission, by PSC Order No. 7035, approved the requested interim increase to become effective November 1, 2006, under bond and subject to refund.

3. On the evening of November 29, 2006, a duly noticed public comment hearing was conducted within Delmarva Power's service territory, in Wilmington, Delaware. No one from the public appeared at the public comment hearing and no member of the public submitted written comments.

4. After conducting discovery, and pursuant to the schedule set in the proceeding, Commission Staff and the Division of the Public Advocate ('DPA ') filed written direct testimony on January 19, 2007. Staff took the position that Delmarva Power should be allowed an additional revenue requirement of $6,565,000, while DPA recommended an increase of $7,917,000. The parties then engaged in additional discovery and conferred with each other in an effort to reach an agreement on the issues in the proceeding.

5. On February 20, 2007, the parties submitted a 'Proposed Settlement Agreement' dated February 15, 2007, which, if approved, would resolve (or defer) all contested issues in the case. The Proposed Settlement calls for an annual revenue increase of $9.0 million, or approximately 3.9 percent of total gas revenues, and reflects a cost of equity of 10.25 percent. It also defers consideration of the BSA until the Commission initiates a generic statewide proceeding regarding decoupling mechanisms for gas and electric distribution utilities. On March 2, 2007, the Company submitted written testimony of William R. Moore Jr. in support of the Proposed Settlement.

6. The parties met for an evidentiary hearing on March 6, 2007. [FN1]The parties introduced their pre-filed testimonies into the record, they described the terms of the Proposed Settlement, and they called witnesses to testify in support of the settlement agreement. The record, which consists of five exhibits and a 49-page verbatim transcript, was then closed. As there were no matters in dispute, briefs were deemed unnecessary. I have considered the entire record of this proceeding and, based thereon, I submit for the Commission's consideration these Findings and Recommendations.

III. SUMMARY OF THE EVIDENCE

7. Delmarva Power. With its Application, the Company filed the written testimony and schedules of nine witnesses; Mark E. Browning, Charles L. Driggs, Kathleen A. White, W. Michael Von-Steuben, Joseph F. Janocha, Kemm C. Farney, Roger A. Morin, John H. Chamberlin and Paul M. Normand. Ex. 2. The Company requested an increase in annual revenues of $14,967,000, or approximately 6.62 percent over current total gas revenues. The Company calculated its rate base to be

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$237,676,296 through the end of the test period, or March 31, 2006. The Company requested a rate of return on equity of 11.00 percent, with an overall rate of return of 8.08 percent. If the proposed BSA were rejected, then the Company requested a return on equity of 11.25 percent.

8. At the March 6, 2007 hearing, Company-witness William R. Moore, Jr. adopted all of the Company's pre-filed testimony and presented his written testimony regarding the terms of the Proposed Settlement. Ex. 2. He testified that adoption of the Proposed Settlement would be in the public interest because it balances the needs of various stakeholders and because the proposed rates will recover the Company's cost of providing service. Tr. 29. He noted that cost recovery is essential to the financial health of the Company's gas business as the Company continues to invest in system reliability. Ex. 2 (Moore) at 5.

9. Commission Staff. Susan B. Neidig, Public Utilities Analyst III, presented the prefiled testimony of four witnesses; David C. Parcell, Executive Vice President and Senior Economist with Technical Associates, Inc.; Michael J. McGarry, Sr., President and Chief executive Officer of Blue Ridge Consulting Group; Howard Solganick, Senior Technical Consultant with Blue Ridge Consulting Group; and Michael J. Majoros, Vice President of Snavely King Majoros O'Connor & Lee, Inc. Ex. 5. In its prefiled testimony, Staff recommended a $6,564,957 increase (3.16 percent) in the Company's revenue requirement, or $8,402,435 less than the Company's requested revenue requirement increase. Staff's proposed revenue requirement was based on several accounting adjustments to the Company's *pro forma* rate base and operating expenses and a recommended 9.75 percent return on equity, with an associated 7.49 percent overall rate of return. In addition, Staff recommended the use of the same five-year net salvage allowance approach for accumulated depreciation that the Commission approved in the Company's most recent electric base rate case (*i.e.* , PSC Docket No. 05-304).

10. Staff also recommended that the Commission decline to implement the Company's proposed BSA because it was not supported by appropriate financial evidence (such as 'backcasting') and would have a disproportionate impact on customers in smaller classes who reduced their consumption. In this regard, Staff recommended that the Commission open a generic proceeding to investigate whether revenue decoupling might be appropriate and, if so, the manner in which it might be implemented. In the event that the Commission approved the Company's proposed BSA, then Staff recommended that the Company's return on equity be reduced by 50 basis points to reflect the greater revenue security that would result from the BSA.

11. At the hearing, Ms. Neidig testified that adoption of the Proposed Settlement would be in the public interest because it avoids further litigation costs, yields a reasonable outcome in light of Staff's filed position, and balances the interests of all the parties. Tr. 45. Ms. Neidig noted that $1.5 million of the $2.5 million difference between Staff's filed position and the negotiated settlement can be traced to the movement from Staff's recommended 9.75 percent return on equity to the 10.25 percent from the settlement, and the associated interest synchronization adjustment. The 10.25 percent, however, is within the return-on-equity range initially recommended by Staff.

12. Division of the Public Advocate. DPA filed the testimony of Andrea C. Crane, who addressed the Company's revenue requirements and made numerous adjustments to cost of capital, rate base, operating expenses and operating income. Ex. 3. Ms. Crane recommended a rate increase for Delmarva Power of $7,916,701, based on a cost of equity of 9.70 percent and an overall cost of capital of 7.47 percent. In addition, Ms. Crane opposed the Company's proposed BSA, which would sever the relationship between the Company's revenues and its sales.

13. Ms. Crane recommended numerous adjustments to the Company's proposed rate base and operating

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income. Based on her proposed eliminations of post-test year compliance costs, construction work in progress, the prepaid pension asset, and the purchased gas cost from the Company's cash working capital, Ms. Crane recommended a rate base of $213,011,902, or approximately $24.7 million less than the Company's claim. Based on her adjustments to salaries and wages, incentive awards, severance costs, payroll taxes, facilities costs, fleet vehicle expense, injuries and damages expenses, advertising costs, gas association dues, rate case costs, disposition of sale proceeds, depreciation, allowance for funds used during construction, and interest synchronization, Ms. Crane recommended a *pro forma* operating income at present rates of $11,217,429.

14. At the evidentiary hearing, Ms. Crane testified that adoption of the Proposed Settlement would result in just and reasonable rates. Tr. 37. She noted that the proposed revenue increase from the settlement is very close to her recommended increase, after substituting the settlement's 10.25 percent cost of equity for her recommended 9.7 percent. She also noted that the increase appears to be fairly distributed among the customer classes.

15. The Proposed Settlement Agreement. On February 20, 2007, the parties submitted a 'Proposed Settlement Agreement' dated February 15, 2007, which will be attached to the proposed Order in this case as 'Attachment B.' Ex. 4. Under the Proposed Settlement, the parties agree that the total base revenue increase awarded the Company will be $9 million, or $6.5 million above the temporary $2.5 million revenue increase already in place. The increase is based on a cost of equity of 10.25 percent and a 7.73 percent overall rate of return. The parties agree to distribute the revenue increase among the customer classes in accordance with 'Exhibit 1' to the Proposed Settlement. Under the terms of the settlement, the rate increase will take effect on April 1, 2007.

16. Depreciation rates are specified in the Proposed Settlement, at 'Exhibit 3.' The depreciation rates include a revised plant-removal cost component, which is based on the last five years of actual cost of removal experience in each plant account. This methodology, along with the rates used in this case for common depreciation expense, were approved by the Commission in the Company's most recent electric base rate case, PSC Docket No. 05-304.The Proposed Settlement, however, does not prohibit the parties or the Commission from re-examining depreciation rates for removal costs in a future base rate case.

17. In addition to the changes in rates, the parties have agreed to certain changes to Delmarva Power's Rules and Regulations, as set forth in three revised Tariff leaves, which are attached to the Proposed Settlement as 'Exhibit 2.' The changes in Rules and Regulations include the proposed increases in the Reconnect and Premise Collection fees. The settlement does not, however, include the proposed BSA mechanism. Instead, the parties agree to participate in a generic statewide proceeding initiated by the Commission for the purpose of investigating decoupling mechanisms for gas and electric distribution utilities.

IV. DISCUSSION

18. The Commission has jurisdiction over this matter pursuant to 26 Del. C. § 201(a).

19. All parties to this proceeding entered into the Proposed Settlement Agreement (Ex. 4), dated February 15, 2007, which is attached to the proposed Order as 'Attachment B.' Under the Proposed Settlement, the parties stipulate to a revenue increase of $9,000,000, which represents a 3.9 percent increase over total gas revenues, or a 15.4 percent increase over gas base (delivery) revenues. Delmarva Power has not increased its gas base rates since a 5.8 percent increase was approved in 2003 (in PSC Docket No. 03-127). According to the Company, the proposed increase is necessary to cover rising operating and capital expenses, which have not been offset by increases in sales. Ex. 2 (Application) at 9-10.

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20. If the Proposed Settlement is approved, the typical 120 Ccf bill for a residential space heating customer (for base rates only) will increase from $49.43 (which includes the $1.87 interim increase that went into effect in November 2006) to $54.55 per month. If the proposed Gas Cost Rate ('GCR ') decrease is taken into account, then the current typical monthly bill, in total, will change from $177.92 to $177.38. Ex. 2 (Moore) at Schedule WRM-1. The GCR proposal (PSC Docket No. 06-285F) is scheduled for Commission consideration on March 20, 2007, the same day that the Commission will consider this case.

21. As noted above, the Company has agreed to withdraw from this case its proposal for a Bill Stabilization Adjustment mechanism, which would serve to 'decouple' revenues from sales by providing for annual rate changes that are tied to per-customer demand. Rather, the parties agree to participate in a generic statewide proceeding dealing with decoupling mechanisms for gas and electric distribution utilities. Regarding the proposed changes to the premise collection fees and reconnect fees, which were accepted as part of the settlement, such changes will increase delivery revenues by approximately $13,200 and will place these fees on the same level as those fees that are currently in place for the Company's electric tariff. Ex. 2 (Application) at 4.

22. Based upon my review of the entire record, I find that the approval of the Proposed Settlement would be in the public interest because it balances the interests of ratepayers and the Company and obviates the need to fully litigate the complex issues raised in the Company's Application. It is clear from the record that the agreement was a product of extensive negotiation between the parties, conducted after the completion of thorough investigations by Staff and DPA, and that it reflects a mutual balancing of various issues and positions. In addition, it is significant that the parties, all of whom maintain that the Proposed Settlement is in the public interest, represent a wide variety of interests. Finally, I note that settlements are encouraged under Delaware law, particularly when supported by all parties. 26 Del. C. § 512.

V. RECOMMENDATION

23. In summary, and for the reasons discussed above, I propose and recommend that the Commission adopt as reasonable and in the public interest the February 15, 2007 Proposed Settlement Agreement ('Attachment B' to the proposed Order). A proposed Order, which will implement the foregoing recommendation, is attached hereto.

Respectfully submitted,

***2** William F. O'Brien William F. O'Brien Senior Hearing Examiner

Dated: March 15, 2007

ATTACHMENT 'B'

PROPOSED SETTLEMENT

On this day, February 15, 2007, Delmarva Power & Light Company ('Delmarva' or the 'Company'), the Delaware Public Service Commission Staff (the 'Staff') and the Division of the Public Advocate ('DPA'), all of whom together are the 'Parties' or 'Settling Parties,' hereby propose a complete settlement of all issues that were raised or could have been raised in this proceeding and to establish final rates as follows.

I. INTRODUCTION AND PROCEDURAL BACKGROUND

On August 31, 2006, Delmarva filed an application with the Delaware Public Service Commission (the 'Commission'), pursuant to 26 Del. C. §§ 201, 301, 304, 306 and other applicable authorities to increase its gas base rates by $14, 967,000 along with proposed modifications to the Company's gas tariff for Reconnect and Premise Collection fees and a

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Bill Stabilization Adjustment ('BSA') mechanism. The application was accompanied by various schedules, tables, and data required by the Commission's minimum filing requirements and the pre-filed testimony of several witnesses. On October 3, 2006, by Order No. 7041, the Commission suspended the proposed rate and tariff changes for a period of seven months, required public notice through newspaper publication, established a time for interventions, and assigned the matter to Hearing Examiner William O'Brien, Esq. for evidentiary hearings and further proceedings. DPA gave notice of its intervention in this matter. Staff also participated in the case. No other entities intervened or participated. On November 1, 2006, pursuant to 26 Del. C. § 306 and Commission Order No. 7035, Delmarva put $2.5 million of its proposed rate increase into effect on November 1, 2006 subject to refund, evidentiary hearings and further proceedings. Pursuant to the Hearing Examiner's directive, a public notice through newspaper publication was made of a public hearing that was held on November 29, 2006 in Wilmington, DE. No one from the public appeared at the public hearing.

Pursuant to the procedural schedule established by the Hearing Examiner, the Parties engaged in discovery with respect to the application and accompanying testimony and other material filed with the Application. On January 19, 2007, Staff and DPA each submitted testimony. The Staff filed testimony in which it took the position that Delmarva should be allowed an additional revenue increase of $6,565,000 and the DPA filed testimony supporting a revenue increase of $7,917,000. The Parties engaged in substantial discovery with respect to their respective testimony.

The Parties desire to avoid the substantial cost which would be incurred if the case were to proceed to evidentiary hearings; and the Parties have conferred in an effort to resolve the issues raised in this proceeding.

As such, it is acknowledged that the Parties differ as to the proper resolution of many of the underlying issues in the rate proceeding and are preserving their rights to raise those issues in future proceedings; however, the Parties believe that settlement of the pending rate proceeding on the terms and conditions contained herein will serve the interest of the public as well as meet the statutory requirement that rates be both just and reasonable.

II. SETTLEMENT PROVISIONS

*3 IT IS HEREBY STIPULATED AND AGREED by Delmarva, Staff, and the DPA that the Parties will submit to the Commission for its approval the following terms and conditions for resolution of this rate proceeding:

A. Rates and Charges.

1. No refunds with respect to the interim $2.5 million revenue increase are necessary.

2. The total base rate revenue increase should be $9.0 million, or approximately 3.9% of total gas revenues. This is an incremental increase of $6.5 million or approximately 2.9% of total gas revenues above the level of rates that became effective on an interim basis on November 1, 2006.

3. The Parties have agreed to the distribution of the base rate revenue changes among all classes of customers as shown in Exhibit 1.

4. A cost of equity of 10.25% for the Company is reasonable and should be adopted for this proceeding. This produces an overall rate of return of 7.73 %.

5. The rates approved for usage on and after April 1, 2007, shall be as set forth in the tariff leafs attached as Exhibit 2.

6. The Parties agree to the depreciation rates shown in Exhibit 3. These depreciation rates are based on a rolling five-year average of actual depreciation expense for the removal cost component of depreciation but this Settlement does not prohibit the

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parties or the Commission from re-examining this issue in a future base rate case.

B. Bill Stabilization Adjustment

1. The Parties agree to participate in any generic statewide proceeding initiated by the Commission for the purpose of investigating Bill Stabilization Adjustments or decoupling mechanisms for electric and gas distribution utilities. The parties will strive to conclude any such proceeding as expeditiously as possible, recognizing there are important policy issues that need to be fully explored. The Parties reserve their rights to argue their positions on the appropriateness of a BSA or decoupling mechanism during the proceeding, which may take the form of a workshop process. The return on equity of 10.25% stated herein does not reflect the adoption of any BSA or decoupling mechanism. The parties reserve their rights to argue that a return on equity adjustment or some other adjustment may or may not be appropriate if a BSA or decoupling mechanism is adopted..

C. Miscellaneous Issues.

1. The Parties agree that the Company's proposed tariff modifications to Leaf No. 25 illustrating the proposed Reconnect and Premise Collection Fees should be approved.

D. Additional Provisions

1. The provisions of this settlement are not severable.

2. This Settlement is the product of extensive negotiations and reflects a mutual balancing of various issues and positions. This Settlement represents a compromise for the purposes of settlement and shall not be regarded as a precedent with respect to any ratemaking or any other principle in any future case. No Party to this settlement necessarily agrees or disagrees with the treatment of any particular item, any procedure followed, or the resolution of any particular issue in agreeing to this settlement other than as specified herein, except that the Parties agree that the resolution of the issues herein taken as a whole results in just and reasonable rates and that the non-rate tariff changes are reasonable and in the public interest.

3. To the extent opinions or views were expressed or issues were raised in the pre-filed testimony that are not specifically addressed in the Settlement, no findings, recommendations, or positions with respect to such opinions, views or issues should be implied or inferred. This Settlement shall not set a precedent, shall not have issue or claim preclusion effect in any future proceeding, and no party shall be prohibited from arguing a different policy or position before the Commission in any future proceeding. The purpose of this Settlement is to provide just and reasonable rates for the customers of Delmarva.

***4** IN WITNESS WHEREOF, intending to bind themselves and their successors and assigns, the undersigned Parties have caused this Proposed Settlement to be signed by their duly-authorized representatives.

J. Mack Wathen Delmarva Power & Light Company

Bruce H. Burcat Delaware Public Service Commission Staff

G. Arthur Padmore Division of the Public Advocate

FOOTNOTES

FN1 The affidavits of publication of notice for the evidentiary hearings (as well as the public comment hearings and the filing of the Application) from The News Journal are included in the record as Exhibit 1. Exhibits will be cited as 'Ex.__' and references to the hearing transcript will be cited as 'Tr. __.'

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Westlaw.

272 P.U.R.4th 339, 2009 WL 246937 (N.H.P.U.C.)

H

Re Energy Efficiency Rate Mechanisms
DE 07-064
Order No. 24,934

New Hampshire Public Utilities Commission
January 16, 2009

ORDER encouraging electric and natural gas utilities to fashion proposals for rate mechanisms and incentives that promote cost-effective investment in energy efficiency.

Commission determines that existing utility rate design and rate mechanisms can pose an obstacle to utility investment in energy efficiency. However, it identifies different rate mechanisms that could be employed to promote such investment, including shareholder incentives for energy efficiency program performance, revenue decoupling through changes in rate design, and revenue decoupling through rate reconciling adjustment mechanisms.

The best approach to implementing rate mechanisms that promote energy efficiency investment, the commission states, is a utility-by-utility approach in the context of an examination of utility-specific costs and revenues. The commission adds that energy efficiency rate mechanisms will need to be tailored to energy efficiency load loss and fixed and variable cost structure for each utility, with incentives designed to fit the potential level of energy efficiency investment for each service territory and customer class.

Commission emphasizes that it does not intend a general departure from cost-based regulation; rather, it commits to finding ways to promote energy efficiency and demand reduction for electric and natural gas utilities under the current cost-based regulatory regime.

ELECTRICITY

GAS

CONSERVATION

REVENUES

RATES

RATES

AUTOMATIC ADJUSTMENT CLAUSES

AUTOMATIC ADJUSTMENT CLAUSES

APPEARANCES: EnergyNorth Natural Gas, Inc. by Steven V. Camerino, Esq. of McLane, Graf, Raulerson & Middleton. P.A.; Campaign for Ratepayers Rights by Robert A. Backus, Esq. and Patrick J. Arnold; New Hampshire Office of Energy and Planning by Amy Ignatius, Esq.; Wal-Mart, Stores East, L.P. by Robert D. Shapiro, Esq. of Rubin and Rudman; The Way Home by Alan Linder, Esq. of New Hampshire Legal Assistance; Conservation Law Foundation by Thomas F. Irwin, Esq. and Kristine E. Draushaar, Esq.; Office of Sustainability Southern New Hampshire University by Pentti J. Aalto; The Jordan Institute by D. Dickinson Henry, Jr.; New Hampshire Department of Environmental Services by Robert R. Scott; Business & Industry Association of New Hampshire by Michael S. Giaimo; Public Service Company of New Hampshire by Gerald M. Eaton, Esq.; Granite State Electric Company d/b/a National Grid by Alexandra Blackmore, Esq.; Unitil Energy Systems, Inc. by Gary Epler, Esq.; Northern Utilities, Inc. by Patricia M. French and by Susan S. Geiger, Esq. of Orr & Reno; Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. by Lisa M. Decker, Esq.; New Hampshire Sustainable Energy Association by Carolyn A. Demorest and Paul Levielle; New Hampshire Sierra Club by Arthur B. Cunningham and Catherine M. Corkery; Environment Northeast by Roger E. Koontz, Esq. and Jeremy C. McDiarmid, Esq.; the Office of Consumer Advocate by Meredith Hatfield, Esq. on behalf of residential ratepayers; and F. Anne Ross, Esq. on behalf of Staff of the Public Utilities Com-

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mission.

Before Getz, chairman, and Morrison and Below, commissioners.

BY THE COMMISSION:

I. PROCEDURAL HISTORY

**1 On May 14, 2007, an order of notice was issued commencing this investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms that would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. The order of notice scheduled a prehearing conference for June 18, 2007.

On May 23, 2007, the Office of Consumer Advocate (OCA) entered its appearance on behalf of residential ratepayers pursuant to RSA 363:28. The following parties filed motions to intervene: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England (KeySpan); Campaign for Ratepayers' Rights (CRR); the Office of Energy and Planning (OEP); Wal-Mart Stores East L.P. (Wal-Mart); The Way Home (TWH); Southern New Hampshire University Office of Sustainability (SNHU); Conservation Law Foundation (CLF); The Jordan Institute (TJI); Department of Environmental Services (DES); Business and Industry Association (BIA); Public Service Company of New Hampshire (PSNH); Granite State Electric Company d/b/a National Grid (National Grid); Unitil Energy Systems, Inc. (UES); Northern Utilities, Inc. (NU); Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (collectively CEG Companies).

On June 21, 2007, Staff filed a letter with the Commission that: (1) recommended the scope of the proceeding be expanded to include natural gas companies; (2) proposed that any *341 party with comments on the scope of the proceeding file its recommendation by June 29, 2007; and (3) suggested that the utilities make a baseline presentation on the issues.

On June 29, 2007, UES filed a motion seeking clarification of the scope of the investigation. Comments regarding the scope of the proceeding were received from CLF, CRR, Northern, OCA, and OEP. The Commission issued Order No. 24,774 (July 12, 2007) granting all petitions to intervene, including the natural gas companies, and broadening the scope of the docket to include distributed generation and other 'displacement' technologies and practices. A baseline presentation by the utilities was set for July 30, 2007.

On July 13, 2007, SNHU filed a report by Pentti Aalto and Roy Morrison entitled 'Appropriate Rate Mechanisms for Utilities.' On August 2, 2007, Staff filed a letter indicating that the parties sought to hold a one-day presentation by several experts representing divergent interests on the application of various rate mechanisms and regulatory approaches to promoting energy efficiency. The Commission scheduled expert presentations for November 7, 2007, by Jeffrey D. Makholm, PhD of NERA Economic Consulting; David Dismukes, PhD of the LSU Center for Energy Studies; and Richard Sedano or Frederick Weston of the Regulatory Assistance Project. The presentations were made on November 7, 2007.

On August 27, 2007, the New Hampshire Sustainable Energy Association (NHSEA) filed a petition to intervene. On February 6, 2008, the New Hampshire Sierra Club (NHSC) filed a petition to intervene to which PSNH objected on February 15, 2008. On April 3, 2008, the Commission granted the petitions, determining that no party would be prejudiced by the late interventions.

**2 On March 13, 2008, the Commission requested additional comments on the issues initially raised in the Order of Notice and stated that the next step in the investigation would require the filing of information from the electric and natural gas utilities concerning whether they had experienced, or expected to experience, declining sales attributable to energy conservation, energy efficiency, or demand response programs. The Commission sought com-

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ments on: (1) whether existing utility rate treatment poses an obstacle to investment in energy efficiency; (2) whether a different rate treatment would promote such investment; (3) the procedural question of whether these issues should be pursued further in this docket, through utility-specific rate cases, as part of a rulemaking, or through some other means; and (4) whether decoupling would constitute an alternative form of regulation under RSA 374:3-a. Environment Northeast (ENE), CLF, UES, National Grid, PSNH, CRR, TWH, Northern, Wal-Mart, SNHU, OEP and OCA all filed comments.

On May 30, 2008, ENE petitioned to intervene out-of-time. On June 30, 2008, CLF filed a motion for a scheduling order, stating that there is an urgent need to reduce greenhouse gas emissions that cause global warming.

II. POSITIONS OF THE PARTIES AND STAFF

On April 11, 2007, the Parties filed comments regarding the following four questions:

A. Unitil Energy Systems

Question (1).

UES stated that, under traditional ratemaking practices, electric and gas distribution companies have a strong incentive to maintain and increase sales in order to generate the revenues ***342** necessary to offset increasing operations and maintenance (O&M) expenses and fund needed system reliability and capital expansion projects. As long as utility profits are linked to selling more electricity or natural gas, UES contended, New Hampshire is unlikely to fully realize the economic and environmental benefits from the utility's participation in reducing demand.

UES asserted that the removal of disincentives alone may not be sufficient to engage the capital resources necessary to realize the potential of energy efficiency and demand response measures. A well-designed revenue decoupling mechanism incorporating an inflation and investment cost tracker mechanism is necessary, as well as allowing the utility the opportunity to place capital investments in demand resources into rate base and earn a return on those investments. UES asserted that revenue decoupling is not a substitute for traditional ratemaking approaches and is more in the nature of a revenue recovery mechanism, rather than a cost recovery mechanism because it does not ensure that a distribution utility can recover its 'prudently incurred, just and reasonable costs' over time. While decoupling may provide increased rate stability and revenue certainty, UES stated it appears to be focused on the recovery of a target level of revenue that only grows with increases in the number of customers which, in UES's experience, is not highly correlated with increases in distribution costs and capital investments.

****3** Question (2).

UES emphasized that fully aligning a distribution utility's financial interests with the State's policy interests in energy efficiency and energy displacement technologies requires: (a) eliminating the disincentives caused by reductions in distribution revenues and earnings attributable to avoidance or displacement of energy consumption; and (b) providing a positive incentive to utilities for investing in energy efficiency and energy displacement. The result of this alignment would be that the financial interests of utilities would cause them to pursue initiatives that are preferred from a public policy standpoint. UES pointed out that the better the alignment and the stronger the incentives, the greater the level of utility investment.

UES suggested several techniques: (a) aligning rate design to provide for fixed cost recovery in fixed changes; (b) revenue requirement adjustments, an automated adjustment to revenue requirements, and corresponding rates to account for changes in costs over time; (c) performance-based ratemaking, an alternative to revenue requirement adjustments that generally provides flexibility to the distribution

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utility to increase rates annually for inflation, net of a productivity factor, without a specific revenue requirements analysis; (d) forecasted test year, addressing inflation by setting future rates based on forecasted test year cost data; (e) step increases, a method of providing for cost recovery after an abbreviated regulatory review of increases for specific items, most notably capital investment programs; (f) tracking mechanisms, an approach to providing cost recovery for highly variable cost items or reconciling rate components; (g) financial incentives for implementation of energy efficiency programs; (h) rate of return incentive, a premium on the rate of return on equity for specific investments; and (i) allowing alternative investments.

Question (3).

UES recommended that the issues raised in this docket continue to be addressed in this docket, while allowing for utility-specific dockets to accommodate the particular circumstances of that utility.

Question (4).

UES stated that it does not believe that decoupling would constitute an alternative form of regulation under the statute. De-linking profits to sales through decoupling, it contends, may be accomplished without disturbing the traditional rate of return regulation formula for arriving at a periodically established revenue requirement.

***343** *B. National Grid*

Question (1).

National Grid observed that existing rate treatment poses an obstacle to investment in energy efficiency because a utility that aggressively pursues energy efficiency may jeopardize its ability to provide excellent service to customers and the company would be working against itself financially. National Grid asserts that ratemaking should be reformed to decouple the revenues that a utility needs to serve its customers from the volume of natural gas or electricity it delivers.

****4** Question (2).

National Grid stated that it believes a different rate treatment would promote energy efficiency investment without eroding the revenues that utilities need to provide excellent customer service. National Grid contended that the link between utility sales and revenues must be broken in order to encourage investment in energy efficiency.

Question (3).

National Grid stated that decoupling utility revenues from sales is critical to the expansion of cost-effective energy efficiency opportunities in New Hampshire. National Grid indicated that decoupling should be employed at the time of a ramp-up in efficiency programs, or when a utility files its next base rate case.

Question (4).

National Grid asserted that decoupling would not necessarily constitute an alternative form of regulation under RSA 374:3-a. It theorized that decoupling can be designed based on cost of service principles using a forecasted test year rather than an historic test year, which is not an alternative form of regulation.

C. Public Service of New Hampshire

Question (1).

PSNH stated that, under current regulatory policies, the rate case process is extensive and lengthy and that 'regulatory lag' creates a disincentive for any significant increases in energy efficiency investments because the shortfall in revenue attributable to energy efficiency measures cannot be recovered until a rate case is filed and new rates are implemented. Elimination of the disincentive would remove the financial obstacle faced by utilities and is

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sound regulatory policy. PSNH asserted that utilities should not be faced with making decisions between increasing energy efficiency and maintaining profitability.

Question (2).

PSNH claimed that there are a variety of approaches that could be used to eliminate the disincentive for energy efficiency investment. The objective in selecting an approach should be to provide the greatest incentive to engage in energy efficiency while minimizing potential negative consequences. Some of the approaches PSNH suggests the Commission consider are: (a) modification of rate design; (b) incentives for engaging in energy efficiency; (c) placing energy efficiency spending on equal footing with other investments; (d) lost fixed cost recovery; and (e) revenue decoupling.

Question (3).

PSNH stated that the Commission should evaluate each utility's circumstances individually and determine the approach to be used on a utility-by-utility basis, using common approaches where feasible.

Question (4).

PSNH stated that an alternative form of regulation necessitates a divergence from 'the traditional methods which are based upon cost ***344** of service, rate base and rate of return.' Unless decoupling is combined with an incentive mechanism, it does not appear that it would be an alternative form of regulation under RSA 374:3-a.

D. Northern Utilities

Question (1).

NU stated that while growing load through the addition of new customers is consistent with public policy favoring clean-burning natural gas, incentives to grow load by current customers is at odds with other public policy goals that favor reduced energy use. Traditional rate design approaches create a relationship between a utility's cost structure and its revenue structure that is inconsistent with energy conservation. Existing rate structures promote important policy objectives that were designed to expand natural gas service to more customers. Recent industry changes contribute to heightened challenges for utilities and their customers and necessitate a reordering of public policy objectives. NU maintained that utilities are dependent upon consumption by customers in order to earn sufficient revenues to cover costs and permit a return.

****5** Question (2).

NU stated that efficiency and renewable energy resources are key to stabilizing and reducing energy costs for consumers in an environment where overall demand growth is outpacing supply deliverability. Rate design and associated revenue recovery mechanisms are important tools relied upon by regulators and stakeholders to achieve policy objectives over time. NU explained that rate design is instrumental in creating specific operating incentives for a regulated utility. NU maintained that the core objective of a decoupling mechanism is to break the link between sales volume and utility revenues. Aligning the utility's interests with increased energy efficiency through a decoupling ratemaking mechanism sets the stage for important changes, resulting in conservation and energy efficiency. NU contended that modifications to rate design to provide for decoupling would preserve the financial stability of a utility during times of shifting demand. Decoupling would afford the utility a reasonable opportunity to recover the costs to serve customers while promoting important state energy policy goals.

Question (3).

NU recommended that the Commission adopt an efficient regulatory process for considering changes such as decoupling, including issuing guidelines

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outlining its view on how ratemaking practices can promote energy efficiency investment. NU also recommended that the Commission consider alternative means of initially establishing a decoupling mechanism for an individual utility or permit one or more utilities to conduct decoupling pilot programs. NU urged that the Commission provide for design flexibility and allow for specific tailoring to each utility.

Question (1).

The OEP, DES Air Resource Division and OCA, (together, the Agencies), stated that they believe current rate design may create barriers to utility investment in energy efficiency. The Agencies theorized that decoupling utility revenue from sales volume would only remove one obstacle to investment in energy efficiency. Other obstacles faced by utilities may include lack of knowledge and capacity, uncertainty about risk and rewards, and institutional inertia. The Agencies asserted that rate mechanisms such as decoupling could be part of an important policy shift away from traditional models of rewarding utilities for selling more energy ***345** and toward selling other services such as energy efficiency. The Agencies noted that it is appropriate to distinguish between the sales impacts of energy conservation and efficiency measures and the sales impact of DSM. The Commission must ensure that any new rate treatments do not compensate utilities for taking steps that they would otherwise take for their own financial interests.

Question (2).

The Agencies stated that it is possible that a different rate treatment would promote energy efficiency investments, but that any rate design to remove barriers must be coupled with incentives to motivate such investments. The Agencies asserted that the critical issues to be resolved include: (a) ensuring that utilities are not compensated more than once for activities that are required in the normal course of business; (b) making sure accounting guidelines are in place for exogenous factors; (c) assuring that the rate treatment aligns the utility incentives for the provision of services with the customer benefit from the services; (d) setting a high standard of monitoring and verifying; (e) assuring that services are efficiently and effectively delivered; and (f) assuring that services are comprehensive to minimize lost opportunities.

****6** Question (3).

The Agencies contended that the basic issue of whether throughput-based rates impact investments in energy efficiency should be pursued through this docket, which should fully explore a range of different rate treatments. This docket should also consider removing barriers to energy efficiency and various types of incentives to increase efficiency.

Question (4).

The Agencies stated that decoupling may be part of an alternative form of regulation as defined in RSA 374:3-a.

F. The Way Home

Question (1).

TWH claimed that low-income residential households continue to face persistent market barriers to energy efficiency investment. TWH stated that substantial demand exists for energy efficiency from low-income residential households, which constitutes the consumer group most vulnerable to price volatility and to the shifting of risk from utilities to consumers. TWH opined that it is likely that decoupling can create a disincentive to the utility to operate efficiently, resulting in greater operating expenses and creating lost revenues.

Question (2).

TWH asserted that, while decoupling can remove disincentives for utilities to promote efficiency, decoupling alone does not create an incentive for energy efficiency and does not encourage investment

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in energy efficiency. Decoupling, it states, could be put in place in conjunction with a mandate for substantial energy efficiency investments and could carry with it distinct regulatory, policy and legal implications. TWH argued, however, that decoupling can expose consumers to significant market risk. TWH also contended that, even assuming energy efficiency investments increase, most low-income families, disabled persons and senior citizens, would not immediately benefit so as to offset the likely price increases. As a result, these groups will likely be exposed to increased energy prices they can little afford. TWH maintained that it is unclear at this time whether decoupling is in the best interest of consumers and whether it will in fact promote energy efficiency.

Question (3).

TWH recommended that the Commission undertake a thorough investigation of the merits of decoupling and revenue guarantee mechanisms in this docket and include in the investigation analyses of the various implementation strategies.

***346** Question (4).

TWH suggested that the parties would be better able to brief the issue of whether decoupling would constitute an alternative form of regulation under RSA 374:3-a after a thorough investigation of the issues in this docket.

G. Conservation Law Foundation

Question (1).

CLF stated that existing rate treatment poses an obstacle to investment in energy efficiency because it links utilities' revenue to the volume of electricity and natural gas sold, providing utilities with a strong incentive to increase sales in order to maximize revenues and profit. CLF claimed that an equally strong disincentive exists to promote energy efficiency or other measures that reduce the volume of electricity and gas sales, creating a situation where it is rarely in the utilities' financial best interest to implement measures that reduce demand. CLF contended that new utility regulation can help meet the challenges of maintaining a stable and reliable power grid and address adverse environmental impacts like air quality and greenhouse gas emissions that effect global warming, by aligning utility interests with the public's interest in lower cost and cleaner, more reliable power.

**7 Question (2).

CLF asserted that decoupling paired with aggressive policies to promote demand-side management (DSM) would result in increased investment in energy efficiency, and described 'decoupling' as a rate treatment that removes the disincentive for utility investment in energy efficiency by breaking the link between utility revenue and energy sales. CLF recommended the following: (a) strong DSM targets with enhanced performance incentives; (b) utility funding of additional DSM recovered through rates; (c) establishment of a preferred 'loading order' for new resources to meet New Hampshire's needs; (d) inverted block rates for some or all customer classes; and (e) update and strengthen least cost integrated planning (LCIP).

Question (3).

CLF urged the Commission to pursue these issues through this docket to a resolution of the policy questions, with the adoption of orders or rules as necessary. CFL stated that the structure for decoupling would be best handled as a compliance filing in this docket.

Question (4).

CLF contended that decoupling could, but need not, constitute an alternative form of regulation pursuant to RSA 374:3-a.

H. Campaign for Ratepayer Rights

CRR agreed with the comments submitted by CLF

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and stated that energy efficiency is the least expensive form of energy. CRR asserted that greater incentives are necessary in order to promote efficiency efforts and that significant attention must be given to additional measures for promoting efficiency. CRR stated that decoupling will remove the disincentive to efficiency, but added that the additional measures to promote efficiency through DSM or direct incentives are needed to best serve the interests of consumers.

I. Wal-Mart

Question (2).

Wal-Mart stated that it supports a well-designed decoupling mechanism in cases where the utility has invested its own capital resources in the implementation of energy efficiency measures. Wal-Mart recommended that the Commission also consider other models that may aid in the advancement of energy efficiency, such as a competitive bid process to afford utilities, businesses, and other third parties the opportunity to develop and implement energy efficiency ***347** programs for customers at the company's expense. Wal-Mart submitted that a properly designed revenue decoupling mechanism must include conditions requiring the utility to meet objectives for each energy efficiency program and should not provide utilities with special protection from decreased sales resulting from competition or variances in sales volumes due to natural causes not directly related to the promotion of energy efficiency programs.

Question (3).

Wal-Mart suggested that the Commission use a generic proceeding to develop uniform decoupling principles. Wal-Mart stated that it believes it is very important to establish a revenue adjustment mechanism and process applicable to all utilities that would involve: (a) determination of an allowed revenue per customer through utility-specific base rate proceedings; (b) a periodic reconciliation of actual and allowed revenues which takes into account deviations in sales volumes due to factors other than the impact of energy efficiency programs; and (c) an adjustment of base rate charges to recover a target level of allowed revenues in a subsequent period.

J. Southern New Hampshire University

****8** Question (1).

SNHU stated that the current regulatory process is based on the needs and values of society a century ago when the perceived need was for economic growth, based on expansion of industry and exploitation of natural resources. The regulatory system that evolved supported the maximization of investment, a utility's fundamental source of income.

Question (2).

SNHU proposed the following changes to the current regulatory procedures: (a) a rate case should establish the utility's cost of doing business and the corresponding revenue needed; (b) the revenue requirement minus customer charges would be divided by the expected kWh sales looking ahead to the following year; (c) deviations from expected revenues would be trued up quarterly within bounds of rate of change and an absolute level; (d) demand charges would be replaced by variable kWh adjustments up or down that reflect actual feeder loading; (e) the utility would be paid to maintain a larger working capital reserve to cover volatility in revenues; (f) the utility rate of return would be adjusted to reflect risk, service quality, and mutually agreed upon investment utilization targets; and (g) the utility would be expected to make investment in, and adjustments to, its system for customers feeding power to it and to optimize its operations in support of the new social needs.

K. Environment Northeast

Question (1).

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ENE stated that existing rate structures pose an obstacle to investments in energy efficiency, and that energy efficiency and DSM are under-utilized energy resources in New Hampshire. A significant contributing factor to under-investment in efficiency, ENE maintained, is the way in which utilities are compensated. Utilities have an economic incentive to sell as much energy to their customers as possible, and the more energy they sell, the more revenue they generate. UNE posits that the inverse is also true. Utilities have an economic disincentive to increase efficiency and DSM because such investments would reduce earnings. ENE emphasized that decoupling is an essential policy choice that should be accompanied by commitments to invest in all cost-effective energy efficiency.

Question (2).

ENE stated that investments in energy efficiency would be promoted by adopting a decoupling mechanism to eliminate current rate disincentives and a performance incentive mechanism. ENE suggested that, in rate proceedings for each utility, the Commission establish ***348** parameters for annual adjustments to allowed revenue requirements to reflect expected changes in costs. In addition, the Commission should determine a decoupling adjustment by comparing the billed revenues to the allowed revenue requirement for the prior period on an annual basis. ENE emphasized that performance incentives should also be adopted to support aggressive implementation of efficiency programs. ENE asserted that the interests of the utilities should be aligned with customer interests for all customers to take advantage of the substantial opportunities which exist to reduce costs through greater investments in efficiency and demand side management (DSM).

****9** Question (3).

ENE urged that the design of the decoupling mechanism be determined in this docket.

Question (4).

ENE stated that decoupling does not appear to be an alternate form of regulation pursuant to RSA 374:3-a since decoupling does not alter the revenue requirement determination.*III. COMMISSION ANALYSIS*

A. Background

The New Hampshire electric utilities administer a group of CORE energy efficiency programs for electricity customers. These programs are funded through the system benefits charge (SBC) assessed on each kWh of electricity consumed and collected as part of distribution rates. [FN1]The New Hampshire natural gas utilities also administer energy efficiency programs for their customers, which are funded through a per therm charge and included in the local distribution adjustment charge.

As part of the Commission's ongoing supervision of the CORE energy efficiency programs, the Commission contracted with a team of consulting firms to conduct a study of the technical, economic and feasible potential for additional energy efficiency savings to New Hampshire customers. This study includes an analysis of primary data (customer surveys and customer site visits), as well as analysis of existing and emerging energy efficiency technologies. The study is intended to provide a better understanding of the potential for additional energy efficiency investment in New Hampshire.

As a result of passage of the Renewable Portfolio Standard (RPS) in 2007, [FN2] the Legislature provided for the collection of alternative compliance payments to fund renewable energy projects. In addition, the Regional Greenhouse Gas Initiative (RGGI) [FN3] mandates the reduction of CO_2 emissions through a cap and trade system that will generate funds to be invested in conservation, energy efficiency and demand response. The RPS and RGGI laws require the Commission to oversee the respective Renewable Energy and Greenhouse Gas Emissions Reduction Funds. In response to these legislative initiatives, the Commission created a

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Sustainable Energy Division that will focus its efforts on administering the two funds to make appropriate investments in energy efficiency and renewable energy. It is also our expectation that significant federal funds may be available to New Hampshire in 2009 for energy efficiency and renewable energy projects as part of a broad federal economic stimulus package.

B. Implementation of Energy Efficiency

Rate Mechanisms

[1-8] We consider energy efficiency rate mechanisms in this docket against the legislative backdrop described above and with a view to the level of energy efficiency attainable in New Hampshire. We point out as well that this proceeding was opened to 'investigate the merits of instituting ...appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency' and to determine the appropriate procedural approach for implementing such rate mechanisms.

****10** Having considered the expert presentations, the utility baseline presentations and the discovery and comments by the parties, we conclude*349 that existing rate design and mechanisms, as a conceptual matter, can pose an obstacle to investment in energy efficiency. We conclude as well that there are different rate mechanisms that could be employed to further promote such investment. We also acknowledge that, as indicated by various parties, there are numerous details that would need to be addressed in order to fashion a rate mechanism that appropriately balances risks and benefits among customers and utilities while pursuing legislative policy goals.

We find, therefore, that the best approach to implementing such rate mechanisms is on a company-by-company basis in the context of an examination of company specific costs and revenues inasmuch as each utility has a unique service territory and customer mix as well as company specific operating costs and rate base investment. Energy efficiency rate mechanisms will need to be tailored to the energy efficiency load loss and fixed and variable cost structure of each company. Incentives will need to fit the potential level of investment for each service territory and customer class. As a result, we encourage the utilities to consider the following when fashioning a proposal for energy efficiency rate mechanisms and incentives in a future rate case filing.

C. Rate Mechanism Options

Energy efficiency rate mechanisms such as revenue decoupling are intended to weaken the link between sales volumes and revenue recovery and lessen the impact on utility revenues associated with reductions in sales volumes from increased efficiency and conservation. There appear to be three primary rate mechanism options: (1) performance incentives, (2) rate design, and (3) reconciling rate adjustment mechanisms.

(1) Performance Incentives

With respect to performance incentives, the Commission has already approved this mechanism in both the electric and natural gas energy efficiency programs. Currently, all electric utilities in New Hampshire participate in the CORE Energy Efficiency Programs. The participating CORE utilities are allowed to earn a shareholder incentive based upon a percentage of the total CORE program budget times a ratio based upon predicted to actual cost benefits and lifetime savings of energy efficiency measures. The CORE shareholder incentive is capped at 12% of program budgets. Natural gas utilities earn a similar shareholder incentive for their performance in the gas energy efficiency programs.

We expect that if utility participation levels increase in the CORE programs, or the natural gas efficiency programs, that utility shareholders will

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earn larger incentive payments. This formula appears to be working and does not require adjustment at this time. However, should any party propose changes to the incentive formula, those changes should be thoroughly documented and should include an analysis of declining energy use and related revenue impacts due to energy efficiency programs as well as an analysis of projected energy use and related revenue impacts.

(2) Rate Design

**11 Revenue decoupling could be also be implemented through changes in rate design. That is, the Commission could consider changes to the fixed charge component of the rate design to more accurately align cost causation of the utility's actual fixed costs with the fixed charge component of the rate design. Any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes. Consistent with its traditional practice, the Commission would consider rate design changes in the context of a rate case.

(3) Reconciling Rate Adjustments

Another option that can be used to implement revenue decoupling is a rate reconciling adjustment mechanism. This model can be either targeted or comprehensive. If revenue *350 decoupling were to reflect a targeted approach, it would pertain only to specific sales volume reductions, such as volume reductions associated with the implementation of energy efficiency programs.

In the alternative, if revenue decoupling were to reflect a comprehensive model, it would pertain to all or nearly all sales volume fluctuations, such as volume fluctuations associated with energy efficiency programs, price changes, weather changes, economic fluctuations, etc. Under this scenario, the utility should provide a reconciliation of actual revenues against target revenues, [FN4] along with detailed explanations of the methodology used to reconcile actual revenues against target revenues.

Regardless of the model used, it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking. Further, depending on the specific company proposal, there could be a potential to inappropriately shift risks. That is, revenue decoupling could enhance the utility's revenue stability and reduce earnings volatility; hence, revenue decoupling may result in a shift of risk away from the utility and toward the customer. Therefore, any revenue decoupling model proposed should be in the context of a rate case so that a utility's return on equity (ROE) can be thoroughly analyzed.

D. Future Energy Efficiency Investments

As discussed above, we expect to learn more about likely future energy efficiency investments in the current energy efficiency study. In considering proposed utility investments we will also look at other available funding sources for such investments including customer initiatives and RGGI funds. We invite utilities in the context of future rate filings to propose energy efficiency investments that are both cost effective and not duplicative of investments of customers or other third parties.

We will analyze each utility proposal and consider implementing appropriate energy efficiency rate mechanisms for New Hampshire utilities in order to promote cost effective energy efficiency measures. We will use the results of the energy efficiency study to assess the potential for additional energy efficiency investment in New Hampshire. We will also consider appropriate utility incentives to the extent that energy efficiency spending has not occurred. We will determine on a case-by-case basis whether utility specific energy efficiency rate mechanisms or incentives constitute alternative regulation pursuant to RSA 374:3-a and will apply appropriate standards of review to proposals that fall within RSA 374:3-a. We do not intend a general departure from cost-based regulation, but commit to

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finding ways to promote energy efficiency and demand reduction for the electric and natural gas utilities under the current cost-based regulatory re- gime.

E. ENE Petition to Intervene Out of Time

**12 ENE describes itself as a non-profit organization that addresses large scale environmental challenges and examines threats to regional ecosystems. ENE has a policy focus relevant to this docket and, as a result, we conclude that it has a substantial interest which may be affected by this docket. We therefore grant ENE's request for intervention.

F. CLF Motion for Scheduling Order

In its motion, CLF asks the Commission to: (1) allow comment on an optimal rate design for promoting energy efficiency in New Hampshire; (2) provide for additional proceedings to implement such a rate design; and (3) issue a final order in this docket. The order we issue today is a final order that addresses the issues outlined by CLF and allows the electric and natural gas utilities to propose rate mechanism to promote energy efficiency in future rate case filings.

Based upon the foregoing, it is hereby

ORDERED, that this investigation is closed.

By order of the Public Utilities Commission of New Hampshire this sixteenth day of January, 2009.

*351 FOOTNOTES

NH

NH.P.U.C. 2009

ELECTRIC UTILITIES

272 P.U.R.4th 339, 2009 WL 246937 (N.H.P.U.C.)

END OF DOCUMENT

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June 2006

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Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings

Summary Opinion

- With natural gas prices expected to remain at high levels, local gas distribution companies (LDCs) face earnings and cash flow pressures as their customers increase conservation efforts. In addition, bad debt expense has increased as more customers face increasing difficulties in paying their bills. Furthermore, LDC volumes remain subject to weather conditions.
- Moody's analyzed its gas LDCs (local distribution companies) and notes that weather normalized winter gas consumption in per customer usage has declined at an increased pace since 2003. This decline coincides with a period of steadily rising natural gas prices for the LDCs and steadily falling heating degree days.
- Had gross margins (gas revenues less cost of gas and associated gas taxes) been fully protected against gas consumption declines on account of customer conservation during the past five winters, they would have been higher by an average of $5.2 million in 2004 and $4.6 million in 2005. One company would have increased its profits by $18.3 and $11.6 million in those two years (3% and 2% of gas margins, respectively).
- Bad debt expense has shown a steady average increase in each of the past four winters, tracking the increase in natural gas prices during the same period.
- Despite the general increase in working capital and natural gas prices, LDC short-term debt has remained relatively flat from 2003-2005.
- Except for a handful of jurisdictions that employ full revenue decoupling (RD) through a mechanism akin to "balancing accounts" (California, Maryland and North Carolina), most companies prefer to keep the weather normalization clause (WNC) rate design separate from the conservation margin tracker.
- While some jurisdictions permit the application for RD to be requested outside the procedural norms of a full rate case, most would prefer a full rate case or rate review.
- LDCs pursuing a full or partial RD feel that it is an important aspect of their rate design requirements and most companies indicated that they would continue filing for it until their regulators gave final approval.
- Moody's observes that in the face of volatile natural gas prices, volatile weather patterns and other exogenous forces that would prompt gas customers to curtail gas consumption volumes from their utilities, LDC earnings and credit metrics will come under pressure.
- LDCs that have, or soon expect to have, RD stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.

Introduction

At this time last year, Moody's published its first study dedicated to the question of gas conservation and its impact on gas LDC earnings and credit ratings (see Moody's June 2005 Special Comment titled *Impact of Conservation on Gas Margins and Financial Stability in The Gas LDC Sector)*. We found that while many companies were aware of the conservation factor and 18 of the 34 gas LDCs followed by Moody's could quantify the loss in their per customer volume consumption, only a handful of companies had taken the step to incorporate it into their rate design so that their gross margins would be unaffected. Last year we also discussed how three companies were approaching this rate design feature through slightly different decoupling mechanisms. While the approach may be different, the concept and end result are not. Companies in the gas utility business are increasingly interested in not only protecting themselves against gross margin variations caused by customer conservation (partial decoupling), but also by weather variations (full decoupling).

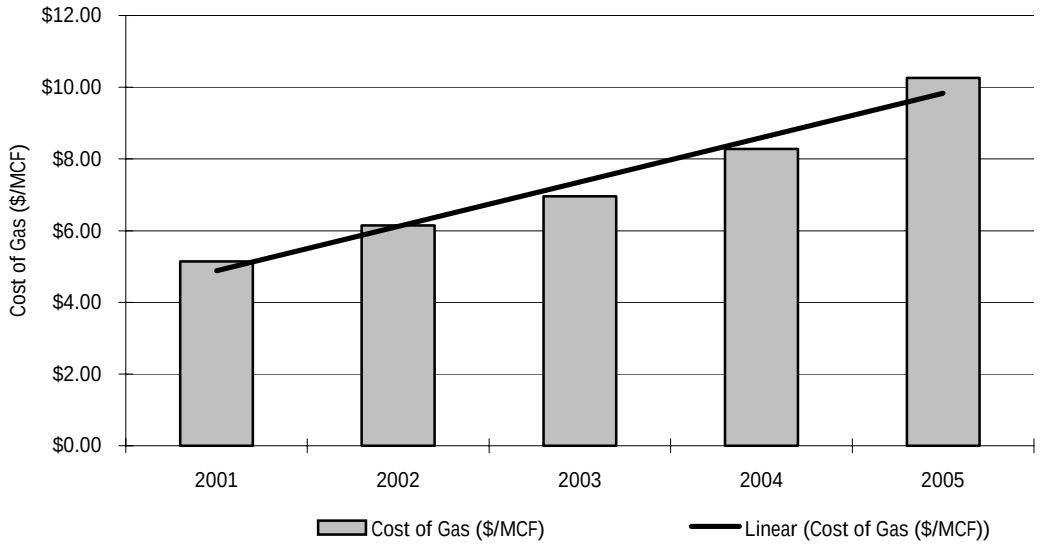
In keeping with the evolving convention, we will refer to these mechanisms as revenue decoupling (RD) in general terms and to "partial decoupling" to mean rate design protection for conservation or "full decoupling" to mean rate design protection for both conservation and weather variations. When a company only has weather normalization clause protection, we refer to the rate design as WNC. Fewer companies have conservation rate design protection without also having WNC as permanent features of their ratemaking.

As with our previous study, we define "conservation" as any technical advancement that improves home heating or gas appliance efficiencies as well as the curtailment of consumption on account of high gas commodity prices. Twenty three of the 34 gas LDCs followed by Moody's responded to various questions posed by Moody's and their results have been tabulated and presented in this paper in aggregate form in order to protect the confidentiality of information submitted.

Nationwide Trend of Rising Gas Prices and Falling Heating Degree Days

Companies overall responded that they were experiencing rising natural gas prices during the past five winter heating seasons, with their average gas purchase prices depicted in the graph below and labeled Increase in Cost of Gas (Fig.1). Natural gas prices rose by a compounded average growth rate of 17% during this period, with the sharpest rise occurring in the winter of 2005 (most recent winter heating season) where it registered an average price increase of 24% over 2004. The highest price recorded by an LDC during this past winter was $13.31/mcf and lowest $6.73/mcf with $10.70 being the median. While only half the respondents provided natural gas price estimates for 2006, those that did resulted in an average price of $10.71/mcf with $13.87/mcf being the highest, $8.61/mcf being the lowest and $10.59/mcf being the median. Most LDCs expect future natural gas prices to moderate, but the trend is still in an upwards direction and this has been found to be the prime driver for the conservation factor on the part of customers.

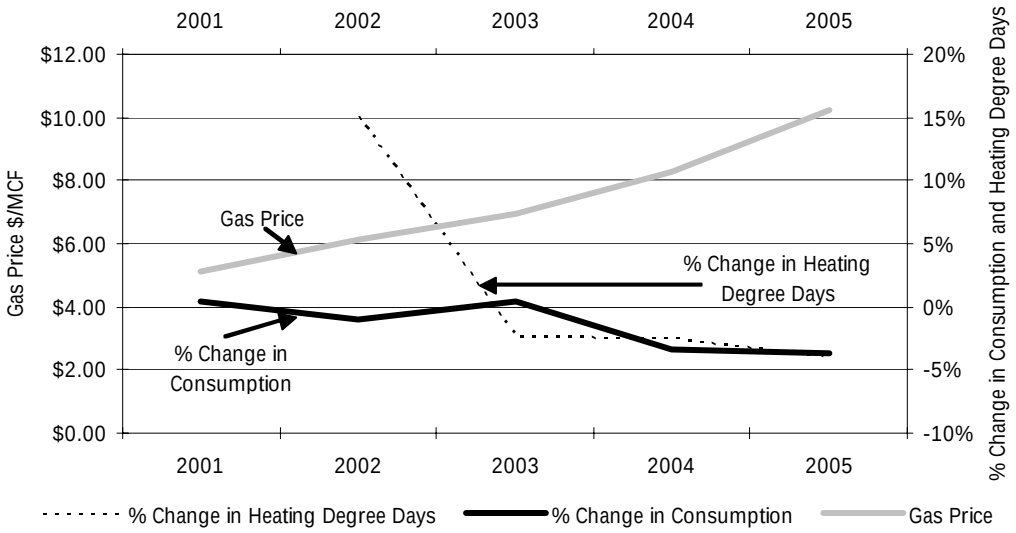
Figure 1
Increase in Cost of Gas to LDCs



The other noticeable trend is that of falling heating degree days since the winter of 2002 among the responding LDCs. On average, the winter of 2002 appears to have been a fairly cold winter, but the number of heating degree days has since fallen by an average of 3-5% in each of the winter heating seasons since that year. LDCs lacking a WNC or full decoupling mechanism would have suffered in their gas consumption and gross margins when faced with the strong combination of warmer than normal winters and declining gas consumption on account of customer conservation.

Finally, except for a period in 2003 when the average customer consumption increased by .5%, the per customer consumption for residential and commercial users has fallen by 3-4% in each of the last two winter heating seasons on a weather normalized basis, representing that portion of loss in gas consumption resulting from conservation. Changes in gas prices are plotted against percentage changes in per customer consumption and heating degree days in Fig. 2. We note that while the change in per customer consumption on account of conservation has been declining since the 2003 winter heating season at a rate of 3-4% p.a., gas prices have continued to rise much more rapidly.

Figure 2
Gas Price vs. % Change in Consumption and Heating Degree Days



The winter of 2005 saw the most dramatic rise in both natural gas prices and also per customer gas consumption decline on account of conservation (4% average decline). The weather normalized consumption decline for the last winter ranges from 9.1% in the case of one LDC to a gain of 3.1% in another, as it had colder winter weather in 2005 compared with 2004. With the exception of another LDC that had no loss in consumption, all the other respondents had declines in gas consumption. Similarly, except for one LDC which experienced an increase in per customer consumption in 2004 of 1.2%, all others saw declines in per customer consumption from 2003 which ranged from -0.2% to -9.6%.

Impact of Conservation on Losses in Gross Margin

When LDCs were asked how much higher would their gross margins (gas revenues less cost of gas purchased and associated gas taxes) have been had they been fully protected against declines in gas consumption resulting from conservation, all indicated higher gross margins for the last two winter heating seasons. The average gross margins would have increased from a low of $2.4 million in 2003 to a high of $5.2 million in 2004, with one company indicating that they would have gained $18.3 million in 2004 alone and $11.6 million in 2005, where the average company stood to gain an additional $4.6 million in gross margin.

The problem of declining gross margins on account of per customer conservation is explained by the various rate filings and testimonies being offered by consultants on the subject. Symptomatic of the LDC conservation problem is

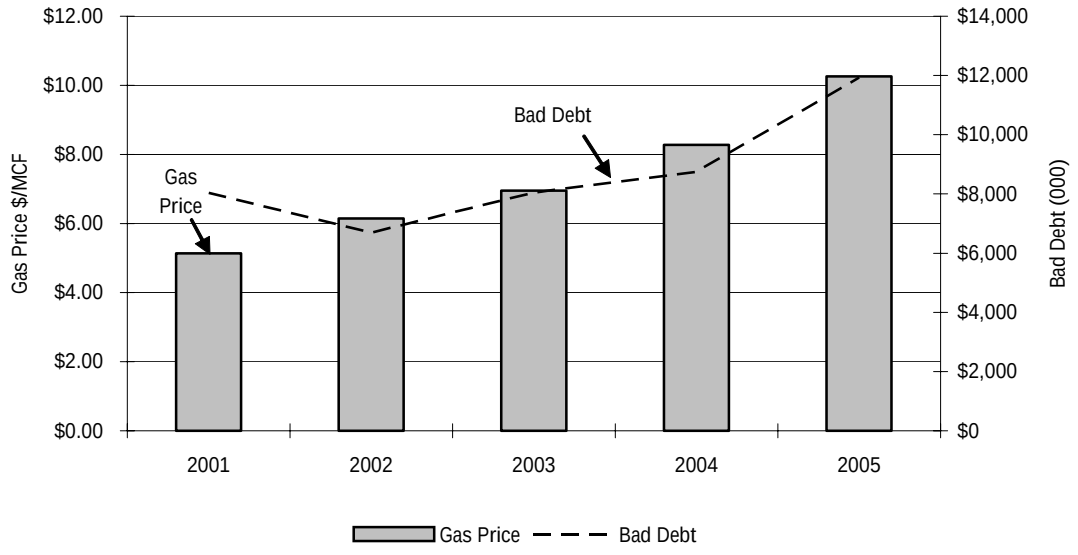
the argument for incorporating a conservation protection design. For example, Questar Gas Company believes that earning its authorized return has been very difficult due to the combination of declining average consumption over time, the use of a historical test year in general rate cases, and the fact that most of its fixed-non-fuel costs are recovered through a volumetric charge. The upshot has been revenues that in normal weather years have fallen short of their own non-gas costs---because average-customer sales in the rate-effective years fell short of the (historical) test-year figures that were used to set rates. Questar would like to decouple its non-gas revenues from year-to-year movements in the per-customer average consumption levels. The mechanics of the decoupling would employ a balancing account to recover non-gas related revenues lost/gained when average consumption drops/rises above the projected average.[1]

In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear therefore, that unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return.

Bad Debt Expense and Increases in Working Capital

One consequence of rising natural gas prices purchased by LDCs and passed onto their customers is the higher level of bad debt expense and increases in working capital that these companies must now contend with. In the winter of 2005 for example, one LDC reported a doubling of their bad debt expense which increased by an average of 17% for all respondents. LDCs in some states such as those located in North Carolina, had the good fortune of being able to recover the gas component of bad debt expense through their purchase gas adjustment (PGA) mechanism, thereby reducing the level of bad debt expense that the company had to absorb on their own. Fig. 3 depicts the close correlation between rising average bad debt expenses and rising gas prices.

Figure 3
Gas Price vs. Bad Debt

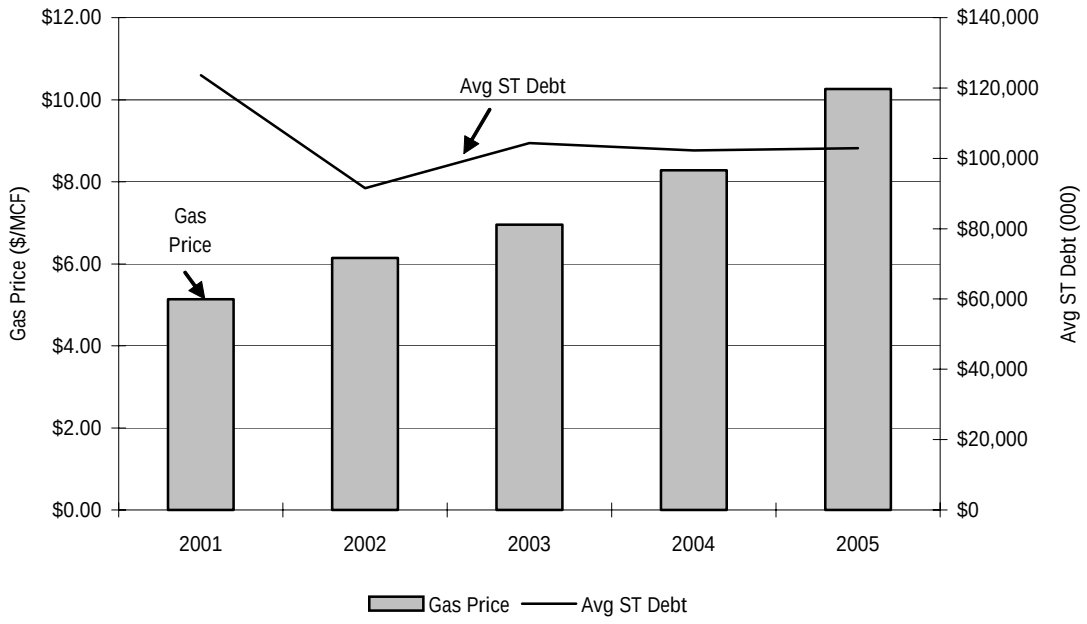


1. *Prefiled Direct Testimony of George R. Compton, Ph.D., for the Division of Public Utilities of the Utah Department of Commerce, Before the Public Service Commission of Utah, January 23, 2006, Docket No. 05-057-T01*

As one would expect, with the higher level of gas commodity prices that customers had to pay and the rise in bad debt expense experienced during the past three winter heating seasons, most LDCs incurred higher levels of working capital. The winter of 2005 witnessed one of the sharpest increases in seasonal working capital on account of accounts receivables and inventory build-ups related to higher natural gas prices, rising 136% over 2004 levels among those LDCs responding to affirmative increases in working capital levels. One large LDC reported a 185% increase in their 2005 working capital level over the prior year. Some companies however, were able to match their increases in accounts receivables and inventory with accounts payable by structuring their gas purchase transactions to more closely match their gas payments for inventory and timing these closer to the anticipated cash receipts from customers, so that they had less working capital to finance.

It is also interesting to note, as depicted in Fig. 4, that on average, LDC short term debt remained relatively flat after 2003 despite the continuing rise in the cost of natural gas prices. Some companies indicated that they were deliberately refinancing short-term debt through medium term notes or through other means of long-term debt by locking in the cost of financing under favorable interest rates, while others were able to contain the increases in their 2005 working capital levels and did not need to borrow as much for their seasonal needs. In fact, approximately half the LDCs indicating having higher levels of working capital in 2005 compared with prior years were able to reduce their short-term debt levels by refinancing via long-term debt or issuance of new equity.

Figure 4
Gas Price Vs. Avg Short Term Debt Outstanding



LDCs Take Varied Approaches in Integrating WNC with RD

It appears that LDCs that already have full RD similar to the "balancing accounts" including revenue normalization adjustments or customer utilization trackers being employed in certain jurisdictions such as California, Maryland and North Carolina, prefer to keep their rate designs intact as they are easily administered and allow for full recovery of their authorized margins. Most other companies that currently have WNC in some of their jurisdictions however, prefer to keep the conservation margin tracker or tariff separate, for the reason that their current WNC provide real time cash flow and earnings adjustments whereas the conservation trackers typically provide after-the-fact cash flow adjustments through deferral accounts that are collected over a subsequent 12-month period.

While some public utility commissions would permit the filing of RD outside the procedural norm of a full rate case, most would clearly prefer a full rate case to be filed in connection with a rate design alteration or at least to review a general rate case after-the-fact in short order. It also appears that the great majority of respondents experiencing customer gas consumption declines on account of conservation would be inclined to file and re-file for some form of RD if denied the first time by their regulators. For many, this is a long but necessary trek to take as a means of curing a rate design deficiency that appears to be increasingly untenable.

Conclusion

In our comment last year, we mentioned several LDCs that had the ability to correct for margin losses on account of conservation or weather variables through their rate design mechanisms, or had RD filing plans or extension plans. Among these, Alabama Gas Corporation (Alagasco) advises that their "rate stabilization and equalization" mechanism will continue through at least 2008 and Southern California Gas Company (SoCal Gas) appears to be satisfied with how their "balancing accounts" have been implemented previously and have requested that the regulatory commission continue with them going forward. Following the completion of an independent study to measure the effectiveness of its conservation mechanism, Northwest Natural Gas Company was able to obtain approval of the Oregon Public Utility Commission in 2005 to continue its conservation tariff for an additional four years through September 30, 2009, and increase the mechanism's coverage from a partial decoupling of 90% of residential and commercial gas usage to a full decoupling of 100%. It also maintains a separate weather normalization mechanism that was extended through September 2008.

In April of 2006, Cascade Natural Gas Corporation in Washington State obtained approval from the Oregon Public Utility Commission to implement a decoupling mechanism to track changes in margin due to conservation (variations in weather-normalized usage) and to track changes in margin due to weather variations from normal for residential and commercial customers. Cascade's RD application for Washington State is still pending.

Piedmont Natural Gas in North Carolina obtained approval for a full RD mechanism for a three-year trial period, with the state's Attorney General appealing the decision in the courts. The appeal has been initiated and the court has taken no action. In the meantime, the company has implemented the mechanism effective November 1 of 2005.

Washington Gas Light Company obtained a full RD (Revenue Normalization Adjustment) in its Maryland jurisdiction which went into effect on October 1, 2005. It has previously attempted to introduce at least partial RD in its Virginia and Washington D.C. jurisdictions.

Southwest Gas Corporation did not fare as well in its Arizona RD application where it generates 54% of its gross margin. The company's credit metrics were already weaker than its Baa utility peers and it badly needed an effective RD mechanism across all its jurisdictions to protect its gross margins. While the Arizona Corporation Commission finally granted it a partial rate increase after over one-year in the application process and brought current recent cost and customer usage factors in Arizona, it denied the company its request for RD through "balancing accounts" as it has in California. The company also lacks RD in its Nevada jurisdiction (37% of gross margins) and the company lost gross margins in 2005 when it experienced one of the 10 warmest years on record, which followed a warm 2003, one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather continued into the company's quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin. Moody's took action in May 2006 to downgrade the company's senior unsecured debt to Baa3 from Baa2 where it is currently under stable outlook.

In the meantime, the list of LDCs applying for RD continues to expand with Atmos Energy Corporation attempting to add conservation riders in key jurisdictions where it already has WNC, Indiana Gas Company and Southern Indiana Gas and Electric Company (utility subsidiaries of Vectren Utility Holdings) both applying for conservation margin protection in Indiana to supplement their recently approved WNC, and Questar Gas Corporation seeking a conservation tariff in Utah. New Jersey Natural Gas and South Jersey Gas Company filed for a joint RD application in New Jersey, requesting a full decoupling mechanism. Both of these New Jersey utilities already have WNC.

Moody's believes that the LDCs successful in their RD initiatives will stand a better chance than others in protecting their gross margins and overall credit metrics from the negative impacts of increasing volatility of natural gas prices and climatic changes. Stronger margins and earnings would also serve to cushion the blows inflicted by increases in bad debt expense that tend to accompany rising gas prices. As gas customers step up their conservation efforts in response to these rising commodity prices, it will become increasingly important for LDCs to switch from a gas volumetric cost recovery methodology to one of RD. While RD may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore.

Related Research

Special Comments:

Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, June 2005 (92798)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversifications and Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Report Number: 98022

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Re Southwest Gas Corporation
Docket No. G-01551A-07-0504
Decision No. 70665

Arizona Corporation Commission
December 24, 2008

OPINION and ORDER authorizing a natural gas local distribution company (LDC) to increase its gross revenues by $33.533 million, reflecting a cost of common equity of 10% and a fair value rate of return (FVROR) of 7.02%. The adopted FVROR is determined based on the application of a weighted average cost of capital to a fair value rate base capital structure and application of an inflation-adjusted, risk-free rate to the increment between original cost rate base and fair value rate base.

Commission approves a rate design that allows the LDC to recover more of its fixed costs through fixed customer charges, while minimizing the burden on any individual rate class. The approved rate design also flattens volumetric charges into a single rate for all usage, eliminating the current declining block rate structure.

The purchased gas adjustor mechanism (PGA) bandwidth is increased to recognize that the LDC needs additional flexibility to respond to volatility in the gas markets. However, the increase in the bandwidth is limited to $0.15 per therm to insulate customers from drastic and sudden increases in gas prices. Revisions to the thresholds for under-collected and over-collected PGA bank balances also are revised to provide the LDC with greater flexibility in dealing with market volatility, while providing a measure of protection to customers from sudden price increases.

Commission disallows from rate base costs associated with the expedited replacement of pipeline, where the evidence indicated that the expedited replacement would not have been necessary but for the improper actions of an employee of the LDC. However, the commission declines to permanently disallow the entire replacement cost in recognition of system betterment.

The LDC is found to have failed to have met its burden of proof with respect to the reasonableness of all of the various miscellaneous expenses for which it sought recovery. However, recognizing that many of the various miscellaneous expenses claimed by the LDC may be legitimate and reasonable business expenses, the commission allows the utility to recover a portion of the claimed costs. The commission rejects the contention that expense items must be presumed reasonable, explaining that the legal test of reasonableness is based on a host of considerations contained in the record and may not be reduced to a simple pass-through of costs claimed by the utility.

Commission disallows from cost of service 40% of the dues paid by the LDC to the American Gas Association (AGA), finding that 40% of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit.

The costs of a supplemental executive retirement plan (SERP) that provides to high-ranking employees pension benefits in excess of the limits placed by Internal Revenue Service regulations are disallowed. The commission finds that the LDC may provide SERP benefits at the expense of its shareholders but that it would not be reasonable to burden ratepayers with the costs.

Commission allows 50% of the management incentive compensation program costs of the LDC on the basis that the program provides approximately equal benefits to shareholders and ratepayers.

Commission declines to approve revenue decoupling mechanisms proposed by the LDC, ruling that the mechanisms first should be fully explored and evaluated as part of a generic docket. It adds that it remains concerned that decoupling could provide a disincentive to customers to undertake conservation efforts by requiring them to pay for gas they did not use. Moreover, the commission states that it appears that, first and foremost, revenue decoupling is a means of providing the LDC with what is effectively a guaranteed method of recovering authorized revenues, thereby shifting a signi-

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ficant portion of the LDC's risk to ratepayers. Nonetheless, the commission expresses the belief that the LDC raised valid 'potential' customer benefits and savings associated with full revenue decoupling. Therefore, to assist in its evaluation of the potential benefits of decoupling, the commission directs the LDC to submit a report showing how the full revenue decoupling mechanisms proposed in this case would have affected customers, if the mechanisms had been in effect for the historical period covering January 1, 2003 through December 31, 2008.

Commission also declines to approve a proposed alternative volumetric rate design, finding that it would shift risk from the LDC to ratepayers and remove the ability of customer to reduce their bills through decreased usage.

P.U.R. Headnote and Classification

1.
VALUATION

s87
Az.C.C. 2008
[ARIZ.] Pipeline replacement - Expedited replacement due to improper actions by employee - Cost disallowance - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

2.
VALUATION

s81
Az.C.C. 2008
[ARIZ.] Natural gas rate base - Pipeline replacement - Expedited replacement due to improper actions by employee - Cost disallowance - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

3.
VALUATION

s70
Az.C.C. 2008
[ARIZ.] System betterment associated with premature pipeline replacement - Potential*467 rate base recognition - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

4.
VALUATION

s87
Az.C.C. 2008
[ARIZ.] Premature pipeline replacement - System betterment - Potential rate base recognition - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

5.
VALUATION

s81
Az.C.C. 2008
[ARIZ.] Natural gas rate base - Premature pipeline replacement - Potential recognition of system betterment - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

6.
VALUATION

s7
Az.C.C. 2008
[ARIZ.] Value for ratemaking - Measures of value - Adjusted original cost rate base - Reconstruction cost new depreciated - Fair value rate base.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

7.
VALUATION

s81
Az.C.C. 2008
[ARIZ.] Natural gas - Total fair value rate base - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

8.
REVENUES

s
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Operating income - Test-year revenues.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

9.
EXPENSES

s5
Az.C.C. 2008
[ARIZ.] Post-test-year general wage increase - Grounds for allowance - Known and measurable expense being incurred on going-forward basis - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

10.
EXPENSES

s8
Az.C.C. 2008
[ARIZ.] Trade association dues - Membership in American Gas Association - Disallowance of 40% - Basis for disallowance - Reasonable approximation of amount for which ratepayers receive no supportable benefit - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

11.
EXPENSES

s0
Az.C.C. 2008
[ARIZ.] Injuries and damages - Method of calculation - 10-year normalization - Exclusion of abnormal expense - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

12.
EXPENSES

s1
Az.C.C. 2008
[ARIZ.] Abnormal expense - Costs not likely to be experience on a going-forward basis - Exclusion from cost of service.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

13.
EXPENSES

s05
Az.C.C. 2008
[ARIZ.] Management incentive compensation - Disallowance of 50% of costs - Recognition of equal benefits to shareholders and ratepayers - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

14.
EXPENSES

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s05
Az.C.C. 2008
[ARIZ.] Extra benefits - Supplemental executive retirement plan - Grounds for disallowance - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

15.
EXPENSES

s9
Az.C.C. 2008
[ARIZ.] Pensions - Supplemental executive retirement plan - Grounds for disallowance - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

16.
EXPENSES

s9
Az.C.C. 2008
[ARIZ.] Miscellaneous expenses - Partial disallowance - Grounds - Failure to provide sufficient justification of inclusion in entirety - Recognition that many miscellaneous expenses may nonetheless be legitimate business expenses - Natural gas rate case.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

***468** 17.
EXPENSES

s
Az.C.C. 2008
[ARIZ.] Ascertainment - Treatment of miscellaneous expenses - Effect of failure to provide sufficient justification for inclusion in entirety - Partial disallowance.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

18.
EXPENSES

s5
Az.C.C. 2008
[ARIZ.] Reasonableness - Standard of review - Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

19.
EXPENSES

s
Az.C.C. 2008
[ARIZ.] Jurisdiction and powers - State commission - As to particular expenses - Power to determine reasonableness - Legal standard.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

20.
EXPENSES

s25
Az.C.C. 2008
[ARIZ.] Natural gas - Adjusted test year operating expenses - Return on fair value rate base - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

21.
RETURN

s6.2
Az.C.C. 2008
[ARIZ.] Reasonableness - Cost of long-term debt - Natural gas local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

22.
RETURN

s6.3
Az.C.C. 2008
[ARIZ.] Reasonableness - Cost of preferred stock - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

23.
RETURN

s6.4
Az.C.C. 2008
[ARIZ.] Reasonableness - Cost of common equity - Estimation methodology - Discounted cash flow models - Risk premium models - Capital asset pricing models - Comparable earnings models - Positions of the parties - Natural gas rate proceeding.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

24.
RETURN

s6.4
Az.C.C. 2008
[ARIZ.] Reasonableness - Cost of common equity - Estimation methodology - Appropriate proxy groups - Natural gas rate proceeding.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

25.
RETURN

s6.4
Az.C.C. 2008
[ARIZ.] Reasonableness - Cost of common equity - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

26.
RETURN

s
Az.C.C. 2008
[ARIZ.] Jurisdiction and powers - State commission - Authority under state constitution.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

27.
RETURN

s
Az.C.C. 2008
[ARIZ.] Basis for computation - State constitutional standard - Fair return on fair value of property.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

28.
RETURN

s5
Az.C.C. 2008
[ARIZ.] Reasonableness - Legal standard - State constitutional provisions - *Hope* and *Bluefield* cases.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

29.
RETURN

s4
Az.C.C. 2008
[ARIZ.] Reasonableness - Factors considered - Sufficiency to maintain credit under efficient management.

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Re Southwest Gas Corporation

P.U.R. Headnote and Classification

30.
RETURN

s5
Az.C.C. 2008
[ARIZ.] Reasonableness - Factors considered - Returns of other enterprises of similar risk.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

31.
RETURN

s6.1
Az.C.C. 2008
[ARIZ.] Reasonableness - Capital structure - Use of actual test year structure - Removal of burden imposed on ratepayers by employment of hypothetical structure - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

*469 32.
RETURN

s6.1
Az.C.C. 2008
[ARIZ.] Reasonableness - Actual test year capital structure - Restructuring for purposes of determining weighted average cost of capital applied to fair value rate base - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

33.
RETURN

s6
Az.C.C. 2008
[ARIZ.] Reasonableness - Fair value rate base cost of capital - Method of determination - Treatment of increment between original cost rate base and fair value rate base - Accounting for effects of inflation - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

34.
RETURN

s2
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Fair value rate of return - Method of determination.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

35.
RATES

s73
Az.C.C. 2008
[ARIZ.] Natural gas - Authorized gross revenue increase - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

36.
REVENUES

s
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Proposed decoupling mechanisms - Concern over disincentive to customer conservation efforts and shifting of risk to ratepayers - Need for further consideration in pending generic docket.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

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37.
CONSERVATION

s
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Proposed decoupling of revenues from gas consumption - Need for further consideration in pending generic docket.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

38.
GAS

s
Az.C.C. 2008
[ARIZ.] Conservation and energy efficiency programs - Proposed decoupling of revenues from gas consumption - Need for further consideration in pending generic docket.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

39.
RATES

s80
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Special factors - Proposed decoupling of revenues from gas consumption - Need for further consideration in pending generic docket.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

40.
AUTOMATIC ADJUSTMENT CLAUSES

s4
Az.C.C. 2008
[ARIZ.] Proposed revenue decoupling adjustment provision - Need for further consideration in pending generic docket - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

41.
AUTOMATIC ADJUSTMENT CLAUSES

s5
Az.C.C. 2008
[ARIZ.] Proposed revenue decoupling adjustment provision - Need for further consideration in pending generic docket - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

42.
REVENUES

s
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Proposed decoupling mechanisms - Need for further study - Report required on how customers would have been affected had full revenue decoupling been in effect for historical period.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

43.
RATES

s80
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Special factors - Pro posed decoupling of revenues from gas consumption - Need for further study - Report required on how customers would have been affected had full revenue decoupling been in effect for historical period.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

44.
RATES

s74
Az.C.C. 2008
[ARIZ.] Natural gas - Proposed volumetric rate design - Grounds for denial - Shifting of risks to ratepayers - Removal of ability ***470** of customers to reduce bills through decreased usage.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

45.
RATES

s43
Az.C.C. 2008
[ARIZ.] Reasonableness - Factors considered - Costs of service - Balancing with principles of gradualism, fairness, and encouraging conservation - Natural gas rate design.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

46.
RATES

s51
Az.C.C. 2008
[ARIZ.] Reasonableness - Factors considered - Gradualism.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

47.
RATES

s73
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Factors considered - Costs of service - Balancing with principles of gradualism, fairness, and encouraging conservation.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

48.
RATES

s78
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Customer charges - Movement toward cost of service - Increased recovery of fixed costs - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

49.
RATES

s73
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Volumetric charges - Flattening into single rate for all usage - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

50.
RATES

s74
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Volumetric charges - Discontinuance of declining block structure - Flattening into single rate for all usage - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

51.
RATES

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s25
Az.C.C. 2008
[ARIZ.] Reasonableness - Low-income customers - Basic monthly charge - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

52.
RATES

s84
Az.C.C. 2008
[ARIZ.] Natural gas rate design - Kinds and classes of service - Monthly increases by class - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

53.
CONSERVATION

s
Az.C.C. 2008
[ARIZ.] Natural gas local distribution company - Energy efficiency and demand-side management - Program analysis and modification - Development of new programs - Increase to authorized budget - Data collection and reporting requirements.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

54.
GAS

s
Az.C.C. 2008
[ARIZ.] Interstate pipeline capacity portfolio - Management by local distribution company - Reasonableness of penalties incurred - Acceptance of commission staff recommendations.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

55.
GAS

s
Az.C.C. 2008
[ARIZ.] Procurement - Policies, practices, and procedures - Local distribution company - Prudence - Best practices - Adoption modified recommendations of commission staff.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

56.
SERVICE

s99
Az.C.C. 2008
[ARIZ] Natural gas extensions - Line extension policy and hookup fees - Incremental contribution model - Need for explanation with sample calculations and documentation - Commission directive to local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

57.
AUTOMATIC ADJUSTMENT CLAUSES

s1
Az.C.C. 2008
[ARIZ.] Purchased gas adjustor mechanism - Modest increase in bandwidth - Balancing of interests - Additional flexibility to respond to market volatility - Protection of customers from drastic and sudden increases - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

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*471 58.
AUTOMATIC ADJUSTMENT CLAUSES

s1
Az.C.C. 2008
[ARIZ.] Purchased gas adjustor mechanism - Revisions to thresholds for under- and over-collected bank balances - Additional flexibility to respond to market volatility - Protection of customers from sudden price increases - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

59.
AUTOMATIC ADJUSTMENT CLAUSES

s3
Az.C.C. 2008
[ARIZ.] Over- and under-collections - Purchased gas adjustor mechanism - Revisions to threshold bank balance levels - Additional flexibility to respond to market volatility - Protection of customers from sudden price increases - Local distribution company.

Re Southwest Gas Corporation

APPEARANCES: Ms. Karen S. Haller, Mr. Justin Lee Brown, and Ms. Meridith J. Strand, on behalf of Southwest Gas Corporation; Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of the Arizona Investment Council; Mr. Timothy Hogan, Arizona Center For Law In The Public Interest, on behalf of Southwest Energy Efficiency Project; and Ms. Maureen Scott, Senior Staff Counsel, and Mr. Charles Hains and Mr. Kevin Torrey, Staff Attorneys, Legal Division, on behalf of the Arizona Corporation Commission.

Before Gleason, chairman, Mundell, Hatch-Miller, Mayes, and Pierce, Commissioners, and Nodes, administrative law judge.

BY THE COMMISSION:

**1 *INTRODUCTION*

On August 31, 2007, Southwest Gas Corporation ('Southwest Gas' or 'Company ') filed with the Arizona Corporation Commission ('Commission') an application for a rate increase. In addition to its rate case schedules, the Company submitted the Direct Testimony of Roger C. Montgomery; Robert A. Mashas; Randi L. Aldridge; Laura Lopez Hobbs; Theodore K. Wood; Frank J. Hanley; James L. Cattanach; Frank J. Maglietti, Jr.; Ralph E. Miller; and A. Brooks Congdon.

On September 25, 2007, Southwest Gas filed revised Supporting Schedule A-2 to its Application.

On October 1, 2007, the Commission's Utilities Division Staff ('Staff') filed a letter stating that the application was found sufficient and classifying Southwest Gas as a Class A utility.

On October 16, 2007, the Residential Utility Consumer Office ('RUCO') filed an Application to Intervene.

On October 23, 2007, a Procedural Order was issued scheduling the hearing in this matter to commence on June 16, 2008; establishing various other filing deadlines; and directing the Company to mail and publish notice of the application and hearing date. RUCO was granted intervention by this same Procedural Order.

On December 11, 2007, Staff filed a Request for Procedural Order seeking amendment to certain of the filing deadlines set forth in the October 23, 2007, Procedural Order.

On December 11, 2007, a Procedural Order was issued granting Staff's request to change certain filing dates contained in the prior Procedural Order. However, the original June 16, 2008, hearing date remained intact as previously scheduled.

On February 1, 2008, Southwest Energy Efficiency Project ('SWEEP') filed a Motion to Intervene.

On March 14, 2008, the Arizona Investment Council ('AIC') filed a Motion to Intervene.

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On March 20, 2008, Mr. Joseph Banchy, on behalf of the Meadows Homeowner's Association filed a Motion to Intervene.

On March 28, 2008, Staff filed the Direct Testimony of Corky Hansen, Frank W. Radigan, David C. Parcell, Phillip S. Teumim, ***472** Robert G. Gray, Rita R. Beale, and Stephen L. Thumb.

On March 28, 2008, RUCO filed the Direct Testimony of William A. Rigsby and Rodney L. Moore.

On April 11, 2008, Staff filed Mr. Radigan's Direct Testimony regarding cost of service and rate design issues.

On April 11, 2008, RUCO filed the Direct Testimony of Mr. Rigsby and Mr. Moore regarding rate design issues.

By Procedural Order issued April 11, 2008, intervention was granted to SWEEP, AIC and Mr. Banchy.

On May 9, 2008, Southwest Gas filed the Rebuttal Testimony of Mr. Montgomery, Ms. Aldridge, Mr. Mashas, Ms. Hobbs, Mr. Wood, Mr. Hanley, Mr. Maglietti, Mr. Miller, Mr. Cattanach, Mr. Congdon, Jerome T. Schmitz, and William N. Moody.

On May 27, 2008, Staff filed the Surrebuttal Testimony of Mr. Smith, Mr. Hanson, Mr. Radigan, Mr. Parcell, Mr. Teumim, Mr. Gray, Ms. Beale, and Mr. Thumb.

On May 27, 2008, RUCO filed the Surrebuttal Testimony of Mr. Rigsby, Mr. Moore, and Marylee Diaz Cortez.

****2** On June 2, 2008, Southwest Gas filed a Motion and Consent of Local Counsel for *Pro Hac Vice* Admission of attorneys Justin Lee Brown and Meridith J. Strand. The Motion was granted at the June 13, 2008, pre-hearing conference.

On June 9, 2008, Southwest Gas filed the Rejoinder Testimony of Ms. Aldridge, Mr. Mashas, Mr. Schmitz, Ms. Hobbs, Mr. Wood, Mr. Hanley, Mr. Moody, Mr. Maglietti, Mr. Miller, and Mr. Congdon.

On June 13, 2008, the Company filed its Certification of Mailing and Publication of the required Public Notice regarding the application and hearing.

On June 13, 2008, a pre-hearing conference was conducted to discuss scheduling of witnesses and other procedural matters.

On June 16, 2008, the hearing in this matter commenced with the taking of public comment and opening statements. The presentation of witnesses for cross-examination also began on June 16, 2008, and continued on June 17, 18, 20, 24, 25, and 26, 2008.

At the conclusion of the hearing, a briefing schedule was established. Initial Briefs were filed on August 8, 2008, by Southwest Gas, Staff, RUCO, AIC, and SWEEP. Final revenue requirement schedules were filed on August 8, 2008, by the Company and Staff and on August 11, 2008, by RUCO.

On August 14, 2008, Southwest Gas filed Revenue Allocation and Rate Design Schedules With and Without any Revenue Increase to Low-Income Residential Customers.

On August 18, 2008, the Company filed an Erratum to Post-Hearing Brief setting forth corrections to the Brief.

On August 21, 2008, Staff filed an Unopposed Request for Extension of Time to File Reply Briefs. Staff's request was granted by Procedural Order issued August 22, 2008, and Reply Briefs were ordered to be filed no later than August 25, 2008.

Reply Briefs were filed on August 22, 2008, by RUCO and SWEEP and on August 25, 2008, by Southwest Gas, Staff and AIC.

On August 28, 2008, Staff filed a substitute Reply Brief that contained non-substantive corrections to the Reply Brief.

Rate Application

In its application, Southwest Gas proposed a net revenue increase of $50,219,828, based on a return of 9.45 percent on Original Cost Rate Base ('OCRB') and a re-

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turn on Fair Value Rate Base ('FVRB') of 7.04 percent. As modified in its final schedules, in the test year ended April 30, 2007, Southwest Gas claimed adjusted operating income of $73,115,474 on OCRB of $1,069,743,402. The Company proposed a FVRB of $1,392,895,487, based on a 50/50 weighting of OCRB and Reconstruction Cost New Depreciated ('RCND') rate base of $1,716,047,572. In its Initial Brief and Final Schedules, the Company suggests, for the first time, that a revenue increase of $57,546,205, based on a FVRB rate of return of 7.74 percent, is 'fair, required by the Arizona Constitution, and necessary to afford the Company a reasonable*473 opportunity to earn its authorized rate of return.' [FN1] (SW Gas Initial Brief at 40.)

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	$1,069,743,402	$1,065,561,602	$1,089,082,745
Rate of Return	9.45%	8.86%	8.83%
Req'd Operating Inc.	101,091,821	94,376,024	96,205,213
Op. Income Available	73,115,474	77,267,330	76,939,110
Operating Inc. Def.	27,976,347	17,108,694	19,266,103
Rev, Conver. Factor	1.6586	1.6586	1.6634
Gross Rev. Increase	46,402,924	28,376,480	32,046,846
FAIR VALUE			
Adjusted Rate Base	$1,392,895,487	$1,388,713,687	$1,463,404,389
Rate of Return	7.74%	6.79%	6.57%
Req'd Operating Inc.	107,810,111	94,293,659	96,205,213
Op. Income Available	73,115,474	77,267,330	76,939,110
Operating Inc. Def.	34,694,637	17,026329	19,266,103
Rev, Conver. Factor	1.6586	1.6586	1.6634
Gross Rev. Increase	57,546,205	28,239,870	32,046,846

REVENUE REQUIREMENT Rate Base Issues

Yuma Manors Pipeline Replacement

[1-5] The only disputed rate base issue involves a pipe replacement project undertaken by Southwest Gas in the Yuma Manors subdivision in Yuma, Arizona. Staff recommends a revenue increase of $28,376,480 based on an OCRB of $1,065,561,602, or alternatively a revenue increase of $28,239,870 based on FVRB of $1,388,713,687. A second FVRB option offered by Staff would result in a revenue increase of $34,919,500. RUCO recommends a gross revenue increase of $32,046,846, with OCRB and FVRB recommendations of $1,089,082,745 and $1,463,404,389, respectively.

**3 A summary of the parties' revenue requirement positions follows:

Pipeline Safety Inspector, Corky Hanson, recommended that Southwest Gas's request for rate base inclusion of costs associated with the replacement of pipe in Yuma Manors be disallowed. Mr. Hanson testified that the Yuma Manors pipeline was replaced prior to the end of its useful life due to improper actions taken by a Southwest Gas employee. (Ex. S-3 at 2.)

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As explained by Staff, pipe corrosion is one the leading causes of pipeline failure. In order to protect underground pipe from corrosion, companies are required to apply cathodic protection ('CP') to metallic pipe. Mr. Hanson stated that CP is accomplished by impressing direct current onto the pipe by use of a 'sacrificial anode' or 'rectifier.' Yearly inspections are required to ensure that CP is being maintained. (*Id.* at 3.)

According to Staff, during Southwest Gas's 2006 annual code compliance audit, it was discovered that the Company had not taken prompt remedial action regarding CP deficiencies identified in 2004 on the Yuma Manors system. After the Company installed a new anode bed and reinitialized the rectifier, the Yuma Manors pipeline experienced approximately 110 leaks, resulting in approximately 20 evacuations. (Tr. at 985.) Most of the leaks occurred in January 2007, at which time Southwest Gas decided to replace the Yuma Manors system. Mr. Hanson testified that the Southwest Gas ***474** technician responsible for making repairs to the CP rectifier system connected the wiring backwards, causing the pipeline to corrode at an accelerated rate. He stated that the pipeline corrosion failures necessitated the immediate replacement of the steel pipeline system and that the Company did not discover the mistake until the system failures occurred. (Ex. S-3 at 2.)

Mr. Hanson conceded that the Yuma Manors pipeline had been in service for approximately 50 years. However, he indicated that, had the reverse CP wiring not occurred, the pipeline system could have lasted for many more years with proper cathodic protection. (Ex. S-8 at 2-3.) Staff recommends that the entire $1,092,448 cost of the Yuma Manors pipe replacement be disallowed from rate base for this case and any future cases.

****4** Southwest Gas contends that the evidence does not support Staff's recommendation to completely disallow the replacement cost of the pipeline. In response to the concerns raised by Staff, the Company agreed to withdraw $320,779 of the replacement costs related to overtime, shift premiums, and other costs caused by undertaking the replacement over a short period of time compared to a more routine replacement schedule. (Ex. A-16 at 13.) Southwest Gas witness Jerome Schmitz testified that Staff's recommendation fails to properly recognize: (1) the age of the replaced pipe (over 50 years old), compared to the 43-year average useful life of steel pipe in Arizona; (2) that the Yuma Manors system did not have CP until 1982, more than half-way through the useful life of the pipe; (3) that not all of the pipe was replaced in the Yuma Manors subdivision, and the leaks were confined to the Manors 3 section of the subdivision; (4) that other factors could have contributed to the pipeline deterioration, such as soil and other environmental conditions; and (5) that the Company made a proactive and cost-effective decision to replace the entire distribution system despite the leaks' being confined to a small area. (Ex. A-13 at 5-10; Ex. A-14 at 2-6.)

Based on all of these factors, Southwest Gas claims that it is reasonable to conclude that the Yuma Manors steel pipeline would have needed to be replaced in the near future. Southwest Gas also asserts that the replacement of the pipe resulted in a better distribution system that benefits the Company's customers. Company witness Robert Mashas stated that Staff's recommendation for a total disallowance is inconsistent with prior Commission Orders that recognized a 'betterment' from the replacement of pipeline, even in instances where the replacement was due to company error. (Ex. A-16 at 8-14.) According to Southwest Gas, the Yuma Manors system had far exceeded its useful life, and the new system is safe and more reliable and will remain in service longer with lower maintenance and repair costs. The Company points out that the Commission's Office of Pipeline Safety has not cited or fined Southwest Gas for the employee error. The Company argued that Staff's recommended 100 percent disallowance is punitive in nature and that adoption of the proposed partial disallowance would achieve a more reasonable result that recognizes betterment of the system and the Company's prudent action to replace the pipeline due to the numerous leaks that occurred.

In its Brief, Staff suggests that the Commission could adopt an outcome somewhere between full disallowance and the Company's proposed partial disallowance to prevent Southwest Gas from benefiting from its employee's error. Alternatively, Staff indicates that the

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Commission could defer inclusion of the costs in this case but allow them in the Company's next rate case. Staff asserts that, at a minimum, the Commission should disallow the $320,779 cost associated with expedited replacement of the pipeline. However, Staff recommends that if the Commission adopts the Company's partial disallowance position, it would be appropriate to assess an additional penalty to reflect the lack of prior fines for the numerous leaks and evacuations caused by the error of a Company employee.

**5 We agree with Staff that the costs incurred by Southwest Gas for expediting the Yuma Manors pipe replacement should be disallowed. We disagree, however, that the entire replacement cost should be disallowed. Southwest Gas *475 raises a valid point that some recognition for system betterment should be allowed to reflect the benefit received by ratepayers from replacement of pipe that had exceeded its average useful life with a newer system that should have fewer leaks and will require less maintenance. On the other hand, the evidence shows that but for the actions of the Company's employee, it is likely that the Yuma Manors system would not have experienced the multitude of leaks that occurred and that the system could have remained in service for a number of additional years.

Based on all of the evidence and arguments presented by the parties, we find that in this proceeding $546,224 should be removed from rate base of which the cost for expediting the Yuma Manors pipeline replacement ($320,779) should be permanently disallowed from inclusion in the Company's rate base. The remaining $225,445 will be potentially included in rate base in the Company's next general rate case. We believe this disallowance gives appropriate recognition and weighting to the competing arguments presented by the Company and Staff and presents a reasonable resolution of this issue. [FN2]

Summary of Rate Base Adjustments

[6, 7] Based on the foregoing discussion, we adopt an adjusted OCRB of $1,066,107,826 and a FVRB of $1,389,259,911.

5p

ORIGINAL COST RATE BASE:	
Gas Plant in Service	$2,052,881,488
Less: Accumulated Depreciation	751,995,287
Net Plant in Service	1,300,886,201
Deductions:	
CIAC	49,194,789
Customer Meter Deposits	34,402,771
Deferred Income Tax Credits	151,878,975
Additions:	
Working Capital	698,160
Total OCRB	1,066,107,826

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RCND RATE BASE:

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Gas Plant in Service	$3,223,228,365
Less: Accumulated Depreciation	1,173,651,142
Net Plant in Service	2,049,577,223
Deductions:	
CIAC	49,194,789
Customer Meter Deposits	34,402,771
Deferred Income Tax Credits	254,265,827
Additions:	
Working Capital	698,160
Total RCND	1,712,411,996
FAIR VALUE RATE BASE:	
Gas Plant in Service	$2,638,054,926
Less: Accumulated Depreciation	962,823,214
Net Plant in Service	1,675,231,712
Deductions:	
CIAC	49,194,789
Customer Meter Deposits	34,402,771
Deferred Income Tax Credits	203,072,401
Additions:	
Working Capital	698,160
Total FVRB	1,389,259,911

5p

Operating Income Issues

In the test year, the Company's adjusted operating revenues were $399,234,678. In its Final Schedules, Southwest Gas reported adjusted test year operating expenses of $326,119,204 and test year net operating income of $73,115,474. As reported in its Final Schedules, Staff's proposed adjusted test year operating expenses are $321,967,348, resulting in test year operating income of $77,267,330. RUCO's Schedules show recommended adjusted operating revenues of $399,234,678, and proposed adjusted test year total operating expenses of $322,295,568, yielding net operating income of $76,939,110. The disputed expense adjustments are discussed below.

***476 Revenues*

6 **[8] There was no dispute between the parties regarding the Company's revenues during the test year. We therefore adopt test year revenues in this proceeding

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of $399,234,678.*Operating Expenses*

2008 Wage Increase

[9] In this proceeding, Southwest Gas has included in proposed test year expenses a 3 percent general wage increase that was given to employees in 2008, in addition to a wage increase given in 2007. Staff does not oppose recognition of the 2008 wage increase because it is a known and measurable post-test-year event. RUCO does not object to inclusion of the 2007 wage increases that became effective in May and June 2007 (after the end of the test year), but proposes to disallow the 2008 increases on the basis that they are too far removed from the end of the test year and would create a mismatch between rate base, revenues, and expenses at the end of the test year. (RUCO Ex. 3 at 23.)

Company witness Randi Aldridge testified that, contrary to RUCO's assertion, the Company included only wage increases for employees who were employed as of the end of the test year, to avoid a mismatch. (Ex. A-10 at 6-7.) She stated that the 2008 wage increase did not apply to any employee hired after the end of the test year (April 30, 2007); therefore, the number of employees at the end of the test year is synchronized with customers served during the test year. (*Id.* at 7.)

We agree with the Company and Staff that the 2008 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by Southwest Gas on a going-forward basis. Because the post-test-year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenues and expenses. Our conclusion is consistent with the treatment accorded this issue in the Company's prior rate case. (*See* Decision No. 68487 at 12-13.)

American Gas Association Dues

[10] The American Gas Association ('AGA') is a national trade association for natural gas distribution and transmission companies. During 2007, Southwest Gas paid to the AGA dues of $401,795, with the Arizona jurisdictional amount being 56.70 percent of the total ($227,920). (Staff Final Sched. C-6.) The AGA provides services to its members in the following categories: Advertising; Public Affairs; Corporate Affairs; General Counsel; General & Administrative Expense; Policy, Planning and Regulatory Affairs; Operations & Engineering Management; Policy & Analysis; and Industry Finance & Administrative Programs. (Ex. A-11, RLA-2.)

In the Company's last rate case. Southwest Gas requested recovery of 96.36 percent of the AGA dues, excluding 3.64 percent of the dues related to the AGA's marketing and lobbying functions. In that case, Staff did not oppose the Company's request, but RUCO proposed disallowance of 39.09 percent of the AGA dues, to exclude the Communications and Public Affairs expense categories. The Commission rejected RUCO's proposed disallowance and adopted the Company's inclusion of 96.36 percent of the AGA dues, finding that '[a]lthough the descriptions of AGA activities provided by the Company [were] somewhat nebulous,' Southwest Gas had satisfied its burden of showing that the AGA functions provide a benefit to the Company and its customers. (Decision No. 68487 at 14.) However, the Commission directed Southwest Gas to provide in its next rate case filing 'a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers. '(*Id.*)

****7** In this case, Southwest Gas seeks recovery of 94.52 percent of its AGA dues, excluding 5.48 percent of the dues as related to marketing and lobbying functions. To satisfy the Commission's directive in the prior Decision, Company witness Aldridge provided testimony describing the AGA's functions, as well as several attachments extolling the virtues of various AGA activities. (Ex. A-10 at 21-24; Ex. A-11, RLA-1 ***477** and RLA-2.) The Company contends that it has provided ample support for the functions provided by the AGA and the benefits that accrue to the Company and its ratepayers as a result of the AGA's activities. Southwest Gas argues that the documentation provided comes directly from the AGA and that there is no better source of information for analyzing the appropriateness of the AGA's activities. The

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Company cites to the testimony of Ms. Aldridge who claimed that AGA member benefits amounted to $479 million, compared to only $18 million in total membership dues. (Ex. A-11 at 9.)

RUCO did not oppose the Company's proposed recovery of AGA dues in this proceeding. However, Staff recommends disallowance of 40 percent of AGA dues on the basis that Southwest Gas has not demonstrated how the AGA's activities provide specific benefits to ratepayers. Staff witness Ralph Smith stated that Southwest Gas failed to substantiate its claims that AGA membership resulted in $479 million in member savings in 2006, and that it is not clear if the claimed benefits have ever been audited or verified. (Ex. S-12 at 40; Ex. S-13 at 33.) Mr. Smith testified that the Company failed to demonstrate why ratepayers should fund activities through membership in an industry organization that would likely be disallowed if they were performed by the Company itself. (*Id.*) Staff's 40-percent disallowance recommendation is based on decisions by other state regulatory commissions and audits of the AGA by the National Association of Regulatory Utility Commissioners ('NARUC '). Mr. Smith cited to orders issued by other commissions in which AGA dues were disallowed in the following percentages: Michigan (16.17 percent), California (25 percent), and Florida (40 percent). (*See* Ex. S-12 at 41-45.) He also cited a 1999 NARUC-sponsored audit of AGA expenditures that stated, 'these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit.' (*Id.* at 43.)

Staff claims that its recommended 40-percent disallowance is consistent with a March 2005 NARUC Audit Report that quantified AGA function categories that Staff believes should not be paid by ratepayers. The categories cited by Staff are: Public Affairs (24.13 percent); Corporate Affairs and International (10.54 percent); half of General Counsel and Corporate Secretary (2.6 percent); and Marketing (2.37 percent).(*Id.* at RCS-2, Sched. C-6.) Staff contends that the 39.64-percent total represented by these activities supports its recommended disallowance. Moreover, according to Mr. Smith, based on the 2007 and 2008 AGA budgets, the recommended dues disallowance would be 43.29 percent and 46.19 percent, respectively (*Id.*;Ex. S-14 at 33-34.)

****8** We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit. The documentation offered by the Company to justify the AGA dues, including the alleged monetary savings to members, consists primarily of information provided by the AGA itself and must be viewed in that context. As Staff witness Ralph Smith indicated, several other states have disallowed AGA dues in substantially higher amounts than the amount proposed by Southwest Gas. Mr. Smith also pointed out that Staff's recommended disallowance is approximately the same percentage as that attained by totaling up AGA activities for Public Affairs, Corporate Affairs, half of General Counsel expenses, and marketing under a 2005 NARUC audit. Further, application of the 2007 and 2008 AGA dues would result in even greater disallowances under these categories. We therefore adopt Staff's recommendation to disallow 40 percent of the Company's AGA dues.

Injuries and Damages Expenses

[11, 12] Southwest Gas and Staff continue to dispute the appropriate amount to be allocated for injuries and damages expenses. The Company has proposed an increase in this expense of approximately $2,490,000, for a total of $8,169,000. Staff recommends reducing the Company's proposed increase to $1,638,000, for a total injuries and damages expense allowance of $7,317,000.

***478** Southwest Gas contends that its proposal is consistent with the methodology agreed to by the parties, and adopted by the Commission, in the Company's last rate case. The Company's proposal utilizes claims in all jurisdictions over a 10-year period and includes recognition of a change in the Company's self-insurance limits during that period. Company witness Mashas testified that from January 1998 through July 2004, the Company's insurance policies provided that Southwest

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Gas was self-insured for up to $1 million of expenses related to a single claim. From August 2004 through July 2005, the Company provided self-insurance for the first $1 million per claim, and also for *aggregate* claims up to $10 million. In August 2005, Southwest Gas acquired an additional policy that covers aggregate claims for amounts between $5 million and $10 million. (Ex. A-16 at 3-4.)

According to Mr. Mashas, Southwest Gas has experienced only one incident since August 2004 in which the claim exceeded the $1 million per incident self-insured amount. The incident in question occurred in May 2005 when a leaking gas fire in Tucson caused several people to be severely burned, and Southwest Gas paid $10 million in a settlement of claims related to the incident. Southwest Gas argues that Staff's removal of this amount from its 10-year average is inappropriate because prior to August 2004, injuries and damages claims over $1 million would have been indemnified by the Company's insurer and would therefore not have been recorded on the Company's books. (*Id.* at 5.) Mr. Mashas claims that Staff's 10-year average is therefore skewed and is inconsistent with the treatment afforded injuries and damages expenses in the last rate case. Southwest Gas argues that Staff's exclusion of the $10 million claim does not reflect the level of self-insurance that the Company expects to experience during the period rates from this case are in effect.

****9** Staff asserts that the $10 million payment related to the 2005 incident should be excluded because it represents an abnormal expense that is not likely to be experienced on a going-forward basis. Staff witness Ralph Smith stated that the leaking gas incident in 2005 was an abnormal event and that Southwest Gas did not demonstrate the leaking gas incident in 2005 was not due to its own negligence; therefore, ratepayers should not bear the burden of the $10 million self-insurance payment. (Ex. S-12 at 62.) Mr. Smith conceded that the Company's proposed methodology in this case is consistent with the resolution of the issue in the last Southwest Gas case, but asserts that the result in the prior case should not dictate the outcome in this case where a different set of facts is presented. (Ex. S-14 at 39.)

Staff contends that the Company's proposed methodology would overstate significantly the amounts recorded on its books for 2006 and 2007 and would far exceed the pro forma expenses allowed in the Company's last rate case. (*Id.* at 41.)Staff claims that there is no single correct method for calculating this expense and that the method used in the last case should not continue to be used if it produces unreasonable results that are not reflective of expected pro forma expenses. Staff points out that its 10-year normalization recommendation, excluding the $10 million for the 2005 incident, still results in an injuries and damages expense allowance that is $1.638 million more than the actual amount recorded for the test year. Staff therefore requests that the Commission adopt its recommendation to reduce the Company's proposal by $851,717, to a total Arizona jurisdictional injuries and damages expense allowance of $7.317 million. (*Id.*, Attach. RCS-7, Sched. C-12.)

We agree with Staff that the 10-year normalization of recorded injuries and damages expenses for Southwest Gas is an appropriate means of calculating the Company's likely pro forma expenses for the period rates will be in effect from this case. We believe Staff has presented a reasonable analysis of the issue by excluding the costs for what appears to be an extraordinary event that occurred in 2005, but is not likely to occur on a going-forward basis. As Staff points out, even under its 10-year normalization recommendation, the Company's allowable injuries and damages expense, for purposes of setting rates in this case, is 29-percent higher than the actual recorded expenses during the ***479** test year. This issue was resolved between the parties in the Company's last rate case, and was therefore not raised as a litigated issue for the Commission to decide. Based upon the evidence presented in this case, we find that the injuries and damages expense calculated by Staff represents a reasonable resolution of this issue. Staff's recommendation is therefore adopted.

Management Incentive Program

[13] Southwest Gas provides compensation in addition to base salaries to certain eligible management employees through its Management Incentive Program ('MIP')

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based on achievement of the following five factors: (1) an improved customer-to-employee ratio; (2) a comparison of the Company's customer-to-employee ratio to its peer utilities; (3) the results of customer satisfaction surveys; (4) three-year weighted return on equity ('ROE'); and (5) a comparison of the Company's ROE to peer utilities. (Ex. S-12 at 27.) In this proceeding, the Company seeks $3.223 million for costs related to the MIP. Staff and RUCO recommend allowing only 50 percent of the MIP expenses, consistent with the Company's last rate case and other more recent decisions by the Commission.

**10 Company witness Laura Hobbs claims that these five factors are directly related to the provision of natural gas service. Southwest Gas contends that achieving these goals helps the Company to attract, retain, and motivate quality employees. (Ex. A-7 at 2-3; Ex. A-8 at 1-2.) She also indicated that annual variable pay for management employees is standard in the industry and that the Company's total executive compensation is less than the market average compared to other western utilities, including Pinnacle West and UniSource.(*Id.*) Southwest Gas argues that the 50-percent disallowance proposed by Staff and RUCO is not based on comparative compensation studies but is based entirely on prior Commission decisions. The Company contends that neither Staff nor RUCO presented any substantive analysis showing that the Company's incentive compensation is unreasonable or imprudent.

Staff and RUCO propose to reduce MIP expenses by 50 percent to recognize that both shareholders and ratepayers receive benefits through achievement of the MIP performance targets, especially between rate cases. Staff witness Smith stated that shareholders and ratepayers stand to benefit from the performance goals, but added that there is no assurance that the award levels achieved during the test year will be repeated in future years. (Ex. S-4, at 9-10).

RUCO witness Rodney Moore testified that the MIP criteria include elements related to financial performance and cost containment goals, which are goals that primarily benefit shareholders. He stated that consistent with a number of prior Commission decisions on this issue, RUCO proposes disallowing 50 percent of MIP costs to recognize that both shareholders and customers receive a benefit from the performance goals included in the MIP. (RUCO Ex. 3 at 29.)

In the last Southwest Gas rate case, as well as several subsequent cases, [FN3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program *480 should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

**11 (*Id.*) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs. [FN4]

Supplemental Executive Retirement Plan

[14, 15] Southwest Gas also offers a Supplemental Executive Retirement Plan ('SERP') to select executives. The SERP provides supplemental benefits for high-ranking employees in excess of the limits placed by Internal Revenue Service ('IRS') regulations on pension plan calculations for salaries above specified amounts. (Ex. S-12 at 30-31.) We explained in the last Southwest Gas case:

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IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service. In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that 'maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees.'

[Decision No. 68487 at 18 (citations omitted).]

Company witness Hobbs testified that the MIP, SIP and SERP are 'key components of [the Company's] prudently managed total executive compensation expense and are vital to the Company's attraction and retention of highly-skilled employees, which ultimately benefits customers.' (Ex. A-8 at 7-8.) She explained that the SERP is an 'unqualified plan,' and therefore payments are not guaranteed. She also stated that contrary to the testimony provided by Staff and RUCO, virtually every other gas and electric utility offers such employees a SERP, and the costs of the SERP are reasonable. (*Id.*)

Staff witness Smith and RUCO witness Moore recommend a total disallowance of SERP expenses. Mr. Smith cites to the prior Southwest Gas rate case, as well as the subsequent UNS Gas, APS, and UNS Electric cases, wherein the Commission disallowed SERP costs. Mr. Moore stated that SERP costs are not a necessary cost for providing service and indicated that the high-ranking officers covered by the SERP are already fairly compensated for their work and are provided a comprehensive array of benefits in addition to salaries. (RUCO Ex. 3 at 30.)

We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

[W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

**12 (Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:

***481** [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[*Id.* at 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Miscellaneous 'Unnecessary' Expenses

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[16-19] Based on his review of data requests, RUCO witness Rodney Moore proposed a disallowance of $185,210 from test year expenses for various miscellaneous expenses that RUCO deems unnecessary for the provision of service to the Company's customers. Mr. Moore testified that RUCO adjusted the Company's proposed operating expenses to remove payments to chambers of commerce and non-profit organizations; donations; club memberships; gifts; awards; extravagant corporate events; advertising; and various meals, lodging, and refreshments. (RUCO Ex. 3 at 27.) In his Surrebuttal Testimony, Mr. Moore cites the following specific miscellaneous expenses as examples of items that should not be recoverable: (1) massages ($2,160); (2) gift certificates to theaters, restaurants, and shopping malls ($18,230); (3) water, ice, coffee, beverages and refreshments for Company offices ($66,422); (4) breakfast, lunch, and dinner for meetings ($71,358); (5) off-site management meetings at various resorts ($8,835); and (6) a Board of Directors meeting at a golf course ($5,365).(*Id.* at 28; RUCO Ex. 6 at 7.)

Through her testimony, Company witness Randi Aldridge stated that RUCO had failed to justify the exclusion of the various miscellaneous expenses identified by Mr. Moore. Ms. Aldridge claimed that the vast majority of the expenditures are reasonable, recurring, and necessary business expenses and should remain in cost of service. (Ex. A-11 at 9-13; Ex. A-12 at 5-8.) Southwest Gas contends that RUCO did not provide specific testimony or evidence regarding its proposed disallowances other than claiming a philosophical difference with the Company regarding such expenditures.

Although Ms. Aldridge accepted exclusion of a portion ($13,904) of RUCO's proposed disallowance, she provided the following additional detail to support the Company's expenses: (1) gift certificates for employee awards and recognition are appropriate expenditures to enhance performance; (2) office refreshments help improve productivity and employee morale; (3) meals provided at meetings outside normal business hours or during training enhance cost-effective operations; and (4) off-site meetings are cost-effective because it allows the Company to avoid owning and maintaining facilities needed to accommodate occasional meetings. (Ex. A-11 at 12-13.) Southwest Gas argues that RUCO has not found the Company's expenditures related to gifts and awards to be excessive or imprudent and the Commission should reject RUCO's proposed disallowances.

****13** In her Rejoinder testimony, Ms. Aldridge claimed that RUCO has not raised a 'reasonable doubt' that the expense items identified by Mr. Moore should be excluded from rates. Rather, she indicates that RUCO simply relies on a 'philosophical difference' with the Company as a basis for the disallowance. (Ex. A-12 at 7.) Ms. Aldridge asserts that she has offered explanations as to how these expenses provide customer benefits or cost savings, and she therefore believes the Company has met its 'burden of proof' on this issue. (*Id.* at 8.)

We do not believe that the Company has met its burden of proving the reasonableness of all of the miscellaneous expenses for which it seeks recovery. Ms. Aldridge offered some ***482** broad, self-serving descriptions of how, in her opinion, ratepayers are provided a benefit from the Company giving gift certificates and awards to its employees, providing meals and refreshments in the office, and holding off-site meetings at resorts. Although gifts, awards, meals, refreshments, and off-site meetings at resorts may offer some employees a benefit, we do not believe Southwest Gas has provided sufficient justification for inclusion of such costs in their entirety. The issue is not just whether employees are happier because they may be a recipient of gifts, but whether those costs are truly necessary for the provision of gas service and thus whether ratepayers should bear the costs of those gifts. As RUCO points out, the Company has yet to explain adequately why the cost of massages, gift certificates, and various meals and refreshments should be the responsibility of ratepayers.

Therefore, because we find that the Company failed to sustain its burden of proof on this issue, but also recognizing that many of these miscellaneous expenses may be legitimate and reasonable business expenses, consistent with the last Southwest Gas rate case, we will disallow half of RUCO's proposed disallowance ($185,210 X 50% = $92,605 disallowance).

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Southwest Gas Legal Argument on Expenses

In its Brief, Southwest Gas cites the case of *West Ohio Gas v. Public Utilities Commission of Ohio*, 294 U.S. 63 (1935), to support its contention that specific expense items, including advertising and promotional costs, must be presumed reasonable. While the *West Ohio Gas* case indicates that 'good faith' should be presumed on the part of a company's managers with respect to the prudence of expenditures, we disagree with the position, advocated by Southwest Gas, that our consideration of the reasonableness of any particular expense may not include recognition of the relative benefits that may be derived from such costs. As we stated in the Company's last rate case, the test of reasonableness is based on a host of considerations presented in the record and may not be reduced to a simple pass-through of costs claimed by the Company in order to pass legal muster. The Commission's ratemaking authority allows precisely the type of analysis that has been conducted with respect to these expense items and is consistent with case law interpreting that authority. (*See* Decision No. 68487 at 21-22.)

Summary of Operating Expense Adjustments

****14 [20]** Consistent with the foregoing discussion, we determine that the Company's allowable test year operating expenses were $321,926,794.

Net Operating Income

Based on the findings above, we will allow adjusted test year operating expenses of $321,926,794, which based on test year revenues of $399,234,678, results in test year adjusted operating income of $77,307,884, a 5.56 percent rate of return on FVRB.

COST OF CAPITAL

As amended at the hearing, Southwest Gas recommends that the Commission determine the Company's cost of common equity to be 11.25 percent. Assuming adoption of a hypothetical 45-percent common equity component in its capital structure, this results in a weighted average cost of capital of 9.45 percent. Staff recommends a cost of common equity rate of 10.0 percent with an overall weighted average cost of capital determination of 8.86 percent. (Ex. S-18, DCP-1.) RUCO proposes adoption of a cost of common equity of 9.88 percent and a weighted average cost of capital of 8.83 percent. (RUCO Ex. 3, RLM-18.)

Cost of Debt and Preferred Stock

[21, 22] There is no dispute between the parties regarding Southwest Gas's cost of long-term debt and preferred stock. Both Staff and RUCO accepted the Company's proposal to ***483** adopt a 7.96-percent cost of long-term debt and a rate of 8.20 percent for preferred stock. (Ex. S-17 at 3; RUCO Ex. 7 at 46-7.)

Cost of Common Equity

[23] Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimation that is both art and science. As evidenced by the competing methodologies employed by the cost-of-capital witnesses in this case, there is no clear-cut answer as to which formula should be used for reaching the appropriate outcome. Rather, the three expert witnesses, Hanley, Parcell, and Rigsby, each rely on various analyses for their recommendations.

Southwest Gas

Southwest Gas's expert witness, Frank Hanley, based his common equity cost recommendation of 11.25 percent on the results of his common equity models, namely, the Discounted Cash Flow ('DCF'), Risk Premium Model ('RPM'), Capital Asset Pricing Model ('CAPM'), and Comparable Earnings Model ('CEM'). According to Mr. Hanley, use of these models is consistent with the Efficient Market Hypothesis ('EMH'), which is based on the premise that investors are aware of all relevant publicly available information in making their investment decisions. (Ex. A-33 at 17-22.) Mr. Hanley stated that, absent evidence to the contrary, it must be assumed that investors are aware of all of the

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models he used in his analysis and that those investors take the models into account in making their decisions. (*Id.*)

In his analysis. Mr. Hanley developed a proxy group of eight comparable gas distribution companies. Based on a historical comparison of financial data for the proxy group and Southwest Gas, Mr. Hanley found that Southwest Gas has earned returns well below those of the other companies in the proxy groups. According to the Company, during the 10-year period ending 2006, Southwest Gas achieved an average return on actual book common equity of 5.72 percent in Arizona, compared to the 11.83 percent average ROE realized by the rest of the proxy group. (*Id.* at 12, FJH-1.)

**15 The Company argues that there is an even greater disparity with the proxy group ROEs if Southwest Gas's greater level of business risk is taken into account, as evidenced by the Standard & Poor's ('S&P') business profile of 'strong' for Southwest Gas compared to the proxy group average profiles of 'excellent.' (Ex. A-34, at 4-5, FJH-15.) The Company also claims its ROE request is reasonable compared to other litigated cases for local distribution companies ('LDCs') across the country over the past year, where the average ROE granted was 10.33 percent, for companies with a common equity ratio of 52.42 percent. (*Id.* at 36, FJH-30.) The Company argues that these comparisons support the need for a higher ROE because Southwest Gas is more risky, from both business and financial risk perspect- ives.

Southwest Gas points out that Staff's recommended ROE is well below the 10.75 percent authorized ROE for APS in Decision No. 69663 (June 28, 2007). (*See* Tr. at 33.) The Company also points out that Southwest Gas has bond ratings from Moody's and S&P of BAA-3 and BBB-minus, respectively, whereas APS has bond ratings from Moody's and S&P of BAA-2 and BBB-minus. Similarly, the Company claims that the business risk and financial risk assigned to both Southwest Gas and APS are 'strong' and 'aggressive,' respectively, indicating that the cost of equity for Southwest Gas should be at least as high as was adopted for APS.(*Id.*) The Company also cites to the *Hope* and *Bluefield* cases, [FN5] for the proposition that the Commission must consider Southwest Gas's greater risk relative to other LDCs when determining an appropriate common equity cost rate.

RUCO

RUCO contends that its proposed 9.88-percent cost of common equity is appropriate given the Company's actual capital structure, the current environment of relatively low inflation and interest rates, and the Company's relatively higher financial risk compared to other ***484** similar LDCs. RUCO witness Rigsby employed both a DCF analysis and his CAPM to reach his recommendation. His DCF analysis yielded a 9.73 percent cost of equity ('COE ') result, while the CAPM resulted in a range of 9.20 to 10.83 percent. (RUCO Ex. 7 at 28.) In reaching his 9.88 percent COE recommendation, Mr. Rigsby took the mean average of his DCF (9.73) and CAPM (10.02) results, and then averaged the DCF and CAPM estimates. (*Id.* at 29.)

RUCO argues that Mr. Rigsby took into account the additional financial risks faced by Southwest Gas and the current economic environment. RUCO points to Mr. Rigsby's testimony that his COE recommendation takes into account anticipated interest rate increases by the Federal Reserve and the impact of such increases on utility stocks. RUCO contends that Mr. Rigsby's analysis of investor views of utility stocks was confirmed by financial analysts and financial reports discussed in his testimony. RUCO asserts that Mr. Rigsby's use of DCF and CAPM models is consistent with prior Commission decisions that have relied on those methodologies. RUCO also claims that the Company's analysis arbitrarily excluded companies from its proxy group based solely on such companies' COE falling below a certain minimum. RUCO argues that its recommended COE of 9.88 percent reasonably reflects a return that is fair to both Southwest Gas and its ratepayers.

Staff

**16 In determining Staff's cost of common equity recommendation in this proceeding, Staff witness David

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Parcell employed three methodologies: DCF, CAPM and CEM. Each of the models was applied to two groups of proxy utility companies, one comprised of the LDCs followed by *Value Line*, except for those companies that have not paid cash dividends, and the second group consisting of the same eight companies used by the Company. (Ex. S-17 at 21-22.)

In his analysis, Mr. Parcell used a constant growth DCF model that resulted in a range for the proxy groups of 9.3 to 10.4 percent. (*Id.* at 25.)His CAPM calculations were based on the three-month average yield for 20-year U.S. Treasury bonds compared to actual returns on equity for the S&P 500 from 1978 through 2006. Mr. Parcell calculated mean and median risk premiums, both arithmetic and geometric, and determined a CAPM range of 9.5 to 9.8 percent for the two proxy groups. (*Id* . at 27-28.)Finally, Mr. Parcell used the CEM methodology by looking at realized returns on equity for several groups of companies (1992-2006) and evaluating investor acceptance of the returns based on the resulting market-to-book ratios. Based on his CEM analysis, Mr. Parcell concluded that an earned return of 10.0 to 10.5 percent should result in a market-to-book ratio over 100 percent and reflect current market conditions. The three methodologies employed by Mr. Parcell produced a 9.3-to 10.5-percent range for cost of equity of the proxy groups, with a mid-point of 9.9 percent. For Southwest Gas, he recommends that the Commission adopt a slightly higher cost of equity of 10.0 percent to reflect the lower equity ratio and lower debt ratings of Southwest Gas compared to those of the proxy groups. (Ex. S-17 at 30-34.) In his Surrebuttal Testimony, Mr. Parcell updated his results based on more recent data and indicated that there was a slight increase in his DCF results, a slight decrease in his CAPM results, and no change in the CEM results. He concluded that the updated data would not change his 10.0-percent recommendation. (Ex. S-18 at 24.)

Staff criticizes the Company's exclusion from its proxy group companies that had a DCF-determined ROE below 9.60 percent, which was based on the Company's claim that such returns are not indicative of those required by reasonable investors investing in an LDC's stock. With respect to the CEM, Mr. Parcell stated that i t is 'designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises.'(*Id.* at 28.)Staff claims that the Company has not supported its argument that Southwest Gas is riskier than other LDCs. Staff contends that the reason for the Company's lower bond ratings, relative to comparable LDCs, is the lower ***485** equity ratio historically maintained by Southwest Gas, which requires the Company to incur higher debt costs. Staff asserts that Southwest Gas should not be rewarded with the higher COE determination based on the Company's historically undercapitalized equity structure. Staff also argues that, with respect to the CAPM, the Company's use of only the arithmetic mean fails to recognize that investors have access to both arithmetic and geometric means information and therefore both should be used for analyzing Southwest Gas's COE. Staff cites to the recent UNS Electric case (Decision No. 70360 at 43), wherein the Commission agreed with Staff that both means analyses are appropriate in determining a company's COE.

Conclusion on Cost of Equity

****17 [24-30]** We believe that Staff's recommended cost of equity capital in this proceeding achieves an appropriate result that is supported by the evidence in the record. Staff witness Parcell's use of the DCF, CEM, and CAPM for the two proxy groups provides a broad range of results that is useful for assessing the reasonableness of Staff's COE recommendation. We agree with Staff that the Company's arbitrary elimination in its DCF calculation of all but two of the companies in its proxy group, based solely on Mr. Hanley's subjective opinion that their ROEs were too low, undermines the results achieved by Southwest Gas's DCF analysis.

As Mr. Parcell explained in his testimony, the COE calculation attempts to estimate the return on investment required by investors taking into account all available information regarding relative risk and alternatives. He stated that although the Company's COE cannot be precisely quantified, through his use of two proxy groups, including the group selected by the Company's witness, Staff has given recognition to Southwest Gas's selected

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proxy companies. (Ex. S-17 at 20-21.)

After reviewing the various proposals summarized herein, and as further described in the testimony prepared by the parties' expert witnesses, we believe Staff's cost of equity capital recommendation is appropriate for determining the Company's overall cost of capital in this proceeding. Staff's overall COE calculation of 9.90 percent, with an upward adjustment of 10 basis points to 10.0 percent, gives recognition to Southwest Gas's lower equity ratio and debt ratings compared to those of comparable companies.

We are not persuaded by the Company's legal arguments that adoption of Staff's cost of equity recommendation would constitute a violation of the Commission's authority under the Arizona Constitution, the case law interpreting that authority, or the *Hope* and *Bluefield* decisions. Article 15, Section 3 of the Arizona Constitution provides, in relevant part, that the Commission 'shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein.' In determining just and reasonable rates, the Commission has broad discretion, subject to the obligation to ascertain the fair value of the utility's property and to establish rates that 'meet the overall operating costs of the utility and produce a reasonable rate of return.' *Scates, et al. v. Arizona Corp. Comm'n*, 118 Ariz. 531, 534, 578 P.2d 612 (Ariz. Ct. App. 1978). Under the Arizona Constitution, a utility company is entitled to a fair rate of return on the fair value of its properties, 'no more and no less.' *Litchfield Park Service Co. v. Arizona Corp. Comm'n*, 178 Ariz. 431, 434, 874 P.2d 988 (Ariz. Ct. App. 1994) (citing *Arizona Corp. Comm'n v. Citizens Utilities Co.*, 120 Ariz. 184 (Ariz. Ct. App. 1978)). The oft-cited *Hope* and *Bluefield* cases provide that the return determined by the Commission must be equal to that from an investment with similar risks made at generally the same time and should be sufficient under efficient management to enable the Company to maintain its credit standing and raise funds needed for the proper discharge of its duties. We believe adoption of Staff's recommendation satisfies this obligation.

Capital Structure

****18 [31-34]** During the test year, Southwest Gas had an average actual capital structure consisting of 43.44 percent common equity, 4.48***486** percent preferred stock, and 52.08 percent long-term debt. (Ex. S-17 at 2-3.) The Company and RUCO agree that the Commission should employ a hypothetical capital structure consisting of 45 percent common equity, 4 percent preferred equity, and 51 percent long-term debt. (Ex. A-30 at 3-13; RUCO Ex. 7 at 50). However, Staff disagrees and recommends that the Commission employ the Company's actual test year capital structure for setting rates in this case.

Southwest Gas supports adoption of a hypothetical capital structure because: (1) its actual capital structure as of March 31, 2008, was 45.1 percent equity; (2) the Company's proposed capital structure contains less common equity than the average common equity ratio of the proxy companies used by Staff; and (3) the Company's proposed hypothetical capital structure contains less common equity than the average common equity of the proxy companies employed by Southwest Gas and RUCO. (Ex. A-31 at 3.)

According to Southwest Gas, the Company has improved its actual common equity ratio from 31.1 percent in 1995 to 45.1 percent as of March 31, 2008, an improvement that is consistent with the Commission's directive in the last rate case for the Company to continue to improve its equity ratio. Southwest Gas also cites to the UNS Gas rate case wherein the Commission adopted a hypothetical 50/50 capital structure, compared to test year equity of 44.67, to recognize and encourage continued improvement of UNS's equity component. (Decision No. 70011 at 36-7.) Southwest Gas argues that its equity ratio improvement should be recognized in a like manner by the adoption of its proposed 45 percent equity component in this case.

The Company also contends that its proposed hypothetical capital structure, consisting of 45 percent equity, is

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significantly below the equity component for recent litigated cases of the Company's proxy companies (52.42 percent) and projected equity ratios for the Company's and Staff's proxy groups (57.5 and 57.8 percent, respectively). (Ex. A-33 at 36; Ex. A-31, TKW-4.) Southwest Gas claims that its proposed capital structure is consistent with the standards set forth in *Bluefield,* which the Company asserts mandates that rates must permit a utility company to earn a return equal to that generally made at the same time, in the same general area, on investments with similar risks. Southwest Gas requests that the Commission approve the hypothetical capital structure recommended by the Company and RUCO.

Although RUCO disagrees with Southwest Gas' overall cost of capital recommendation, it agrees with the Company's hypothetical capital structure proposal. RUCO witness William Rigsby stated that he adopted the Company's hypothetical structure in his analysis because Southwest Gas is close to the average debt and equity percentages in his sample group of LDCs. The capital structures for his sample group averaged 45.9 percent long-term debt, 0.20 percent preferred equity, and 53.9 percent common equity. (RUCO Ex. 7 at 48-9.) Mr. Rigsby stated that RUCO's proposed hypothetical structure would provide Southwest Gas with 'additional operating income and cash flows that will offset any perceived financial risk.'(*Id.* at 50.)RUCO therefore recommends that the Commission adopt the hypothetical capital structure proposed by Southwest Gas.

****19** Staff recommends that the Commission adopt the Company's actual test year capital structure, which consists of 43.44 percent common equity, 4.48 percent preferred stock, and 52.08 percent long-term debt, for purposes of determining Southwest Gas's overall cost of capital in this proceeding. Staff witness David Parcell testified that the equity ratio of Southwest Gas has been consistently lower than that of other LDCs. Mr. Parcell cited to the Company's last rate case in which the Commission adopted a hypothetical capital structure of 40 percent common equity, 5 percent preferred equity, and 55 percent long-term debt, but required Southwest Gas to submit a 'recapitalization plan' to explain how the Company intended to achieve an actual 40 percent equity ratio. Staff asserts that because Southwest Gas has now exceeded the prior hypothetical equity ratio, and has achieved an equity component 'more in line with that of other gas utilities,' ***487** there is no need to employ a hypothetical capital structure in this case. (Ex. S-17 at 18-19.) Staff cites to Decision No. 68487 to support its position. In that case, the Commission granted Southwest Gas's 40 percent equity ratio, but warned the Company: 'At some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure. '(*Id.* at 25.)

We agree with Staff that use of the Company's actual test year capital structure is appropriate in this proceeding. As the passage quoted above indicates, there was clearly an expectation that we would hold Southwest Gas to its actual capital structure so that its ratepayers would be relieved of the burden imposed by employment of a hypothetical capital structure. Southwest Gas is to be commended for the progress it has made over the past decade to improve its equity position relative to debt, and we recognize that the Company has now surpassed the target equity ratio that was employed in the last case to, in part, provide a continuing incentive to improve its capital structure.

We are not persuaded by the Company's argument that we should adopt a hypothetical structure in this case because the UNS Gas case employed a hypothetical equity component. As Staff witness Parcell pointed out, ratepayers have for many years been burdened with an authorized return set using a hypothetical capital structure far greater than the Company's actual equity ratio, and Southwest Gas was admonished in its last case that it must improve its equity ratio or 'live with the results of its actual capital structure. '(*Id.* at 25.)We wish to make clear that Southwest Gas's equity improvements are commendable. However, we do not believe that the 'hypothetical equity bar' should continue to be raised in perpetuity with ratepayers consigned, like Tantalus, to see the 'fruit' of an actual capital structure forever just beyond their reach. Rather, the time has come for

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Southwest Gas to live with its actual test year capital structure.

**20 We are mindful of the Company's argument that a hypothetical capital structure was employed for UNS Gas in its last rate case and the Company's claim that there is no distinction that merits different treatment for Southwest Gas in this case. Although we adopted an equity ratio for UNS Gas that was higher than the ratio in its actual test year capital structure, we also indicated that 'it is likely that use of [UNS Gas's] actual capital structure in future rate cases would produce a reasonable cost of capital result.' (Decision No. 70011 at 39.) Thus, UNS Gas was also given a warning that, absent extraordinary circumstances, its actual capital structure would likely be used in its next rate case. We believe the treatment of both companies is consistent. Accordingly, we adopt Staff's recommended capital structure. [FN6]

Chaparral City Decision and Fair Value Rate of Return

On July 28, 2008, the Commission issued Decision No. 70441, which addressed a Remand Order by the Arizona Court of Appeals [FN7] for the Chaparral City Water Company ('Chaparral City'). In Decision No. 70441, the Commission observed that Arizona appears to be the only state that continues to have a FVRB requirement and that most other states use OCRB for determining rate base and setting rates. (*Id.* at 33.)The Commission pointed out that the methodologies commonly applied for estimating a company's cost of equity and weighted cost of capital are typically applied to OCRB and reflect inflation that indirectly compensates companies for that component. The *Chaparral City* Decision went on to state that because the FVRB also includes inflation, it is necessary to exclude an inflation component from the overall rate of return to avoid overstatement of that component. (*Id.*) The Commission concluded:

Because the weighted average cost of capital includes inflation, if the Commission were to apply that cost of capital as the FVROR [Fair Value Rate of Return] to the FVRB (which includes inflation in the RCND portion), then the impact of inflation would be overstated, and the resulting revenues would compensate *488 the utility for more than the fair value of its property, resulting in rates and charges that were not just and reasonable.

(*Id.*)

The Commission went on to state that although the FVRB methodologies proposed by both Staff and RUCO would result in a fair value rate of return on FVRB, a modified version of RUCO's method was appropriate in that case. (*Id.* at 34.)In setting the authorized FVROR for Chaparral City, the Commission agreed with RUCO that the weighted average cost of capital ('WACC') should be adjusted to remove inflation from the cost-of-equity component but not from the debt component. Accordingly, the Commission continued to apply the previously adopted weighted cost of debt (2.11 percent), but subtracted 2 percent from Chaparral City's cost of equity (from 9.3 percent to 7.3 percent). When applied to the equity portion of the capital structure, this resulted in a fair value weighted cost of equity, 'excluding inflation,' of 4.29 percent. By adding the weighted costs of equity and debt, the Commission concluded that a total adjusted WACC of 6.40 percent was an appropriate rate of return on FVRB for Chaparral City. (*Id.* at 36-38.)

**21 The hearing in this matter concluded before the issuance of Decision No. 70441. Therefore, no party had the opportunity to present evidence based on the Commission's analysis of the FVRB issue in that Decision. However, in this case, Staff recommended that the Commission use a fair value capital structure to determine the weighted average cost of capital to be applied to the FVRB. Specifically, Staff recommended that, in determining the rate of return, the Commission assign a zero value to the 'fair value increment' (*i.e.*, the difference between FVRB and OCRB) on the basis that applying the cost of capital to the Company's FVRB would result in a windfall to shareholders because the fair value increment is not financed with investor-supplied funds. (Ex. S-17 at 42-44.) Mr. Parcell proposed (as modified in Staff's Final Schedules) that, for purposes of determining the WACC to be applied to FVRB, the Company's capital structure be restructured with 39.96 percent assigned to long-term debt, 3.44 percent

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assigned to preferred stock, 33.33 percent assigned to common equity, and 23.27 percent assigned to the fair value increment. Applying these percentages to the same cost factors proposed by Staff, and adopted above (and a 0.00 percent cost for the fair value increment), would result in a total FVRB cost of capital of 6.70 percent.(*Id.* at 44; Staff Final Sched. D.)

Staff presented an alternative proposal in the event 'the Commission determine [s] that there should be a specific return (greater than zero) applied to the FVRB Increment.'(*Id.* at 45.)Mr. Parcell's alternative proposal would apply a 1.25 percent value to the fair value increment, if the Commission is persuaded 'that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost.'(*Id.*) Staff's alternative proposal was calculated by taking the 'risk-free return' (the return on an investment that carries little or no risk) of 4.5 percent, [FN8] less an inflation rate of 2.0 percent, to achieve a real risk-free rate of 2.50 percent. Mr. Parcell then advocated that if the Commission chooses to adopt this alternative, it should award no more than half of the real risk-free rate (1.25 percent) to recognize that any amount above zero effectively represents a bonus on the return already earned by investors. Applying the 1.25 percent cost to the fair value increment would result in an overall FVRB cost of capital for Southwest Gas of 7.08 percent. (*Id.* at 47-48; Staff Final Sched. D.)

Southwest Gas disagrees with Staff's recommendation to apply a zero value to the fair value increment Company witness Hanley conceded that 'it has long been established in regulatory ratemaking that application of [WACC to OCRB] provides for a fair and reasonable opportunity to earn a return.' (Ex. A-34 at 38.) However, Mr. Hanley testified that using Staff's primary recommendation to apply a zero value in this case would result in a dollar return that is $80,215 *less* than under a strict OCRB calculation, which he claims is illogical. (Ex. A-35 at 17.) Southwest Gas agrees in concept with ***489** Staff's alternative proposal, that applying a net of inflation risk-free rate to the fair value increment is appropriate, but Mr. Hanley believes that Staff's reduction of the calculated risk-free rate to 1.25 percent is arbitrary and should be rejected. (Ex. A-34 at 39-40.) According to Mr. Hanley, the 4.50 percent risk-free rate determined by Mr. Parcell should instead be reduced by 2.45 percent, to account for expected inflation, with the remainder of 2.05 percent applied to the fair value increment. (*Id.* at 40.)Applying the 2.05 percent risk-free rate advocated by the Company to the fair value increment under the alternative suggested by Staff would produce a total FVRB cost of capital of 7.28 percent. (*See* Ex. S-17 at 48.)

Conclusion on Fair Value Rate Base Issue

****22** Based on the record before us, we believe that Staff's alternative FVRB recommendation is appropriate, with a slight modification. Although we agree with Staff that it should not be necessary to provide the Company with any additional return on the increment between OCRB and FVRB, because that increment is not financed with investor-supplied funds, we find that applying a 1.00 percent return on the fair value increment is appropriate under the facts of this case and properly accounts for the effect of inflation. Applying the adjusted WACC to the FVRB results in a fair value rate of return of 7.02 percent.

As Staff witness Parcell points out, the nominal risk-free rate represented by long-term U.S. Treasury Securities is approximately 4.5 percent. When the inflation factor is removed from the risk-free rate, which inflation rate was determined by the Company's witness to be 2.45 percent, the resulting inflation-adjusted risk-free rate is 2.05 percent. According to Mr. Parcell's alternative recommendation, if the Commission chooses to modify the Company's fair value rate of return, the adjustment should be within the range of zero to the inflation-adjusted risk-free rate (2.05 percent according to the Company). Mr. Parcell recommended that such an adjustment should be at the low end of the range and under no circumstances greater than the mid-point of the range because returns on the fair value increment represent a bonus or windfall to investors beyond the return that is already provided for under a traditional weighted cost-of-capital calculation. Even the Com-

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pany's witness concedes that application of the WACC to OCRB provides a fair and reasonable opportunity to earn a return. The Company's witness, Mr. Hanley, disagrees only with Staff's quantification of the risk-free rate, on the basis that once inflation is removed, no additional adjustment should be made. We agree with Staff, however, that an adjustment in the range identified by Mr. Parcell is within our discretion. Setting the rate at the approximate mid-point of the inflation-adjusted risk-free rate is a reasonable determination in this case.

We recognize that the methodology employed in this case differs from that used by the Commission in the *Chaparral City* Remand Order (Decision No. 70441). This is because the facts and arguments before us differ. In this case, Southwest Gas and Staff do not dispute that the weighted cost of capital is applicable only to the OCRB and that it is appropriate to recognize an inflation factor when calculating the FVROR. As set forth above, we adopted in *Chaparral City* a modified version of RUCO's proposal and deducted directly from the established cost of equity a 2.0 percent inflation factor to arrive at the overall fair value rate of return. In the instant proceeding, no similar proposal was set forth by RUCO or any other party, and we do not have a record before us to make an adjustment on the same basis as that made in *Chaparral City*. Instead, we have a record that reflects agreement between the Company and Staff (as an alternative recommendation) that it may be appropriate to determine the FVROR based on the application of a WACC adjusted to a FVRB capital structure and application of an inflation-adjusted risk-free rate to the increment between the Company's OCRB and FVRB.

**23 We find that a FVROR based upon the WACC derived by using a 1.00 percent adjusted risk-free rate applied to the fair value increment complies with the constitutional fair value requirement and satisfies the concerns expressed by the Court of Appeals in the remanded*490 *Chaparral City* case, is an appropriate methodology identified in Decision No. 70441 to determine the fair value rate of return without overstating the effects of inflation, and will result in just and reasonable rates. For these reasons, we believe that adoption of Staff's alternative recommendation for a 10.0 percent cost of equity capital, and an overall 7.02 percent FVRB cost of capital comply with these obligations.

5p

	Percentage	Cost	FVRB Weighted Cost
Common Equity	33.33%	10.0%	3.33%
Preferred Equity	3.44%	8.20%	0.28%
Long-Term Debt	39.96%	7.96%	3.18%
FVRB Increment	23.27%	1.00%	0.23%
			7.02%

AUTHORIZED INCREASE $33,533,844.

[35] Based on our findings herein, we determine that Southwest Gas is entitled to a gross revenue increase of

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5p

Fair Value Rate Base	$1,389,259,911
Adjusted Operating Income	77,307,884
Required Rate of Return	7.02%
Required Operating Income	97,526,046
Operating Income Deficiency	20,218,162
Gross Revenue Conversion Factor	1.6586
Gross Revenue Increase	33,533,844

RATE DESIGN ISSUES

In its application, Southwest Gas proposed four separate rate design changes that it asserts would help address the financial instability experienced by the Company over a number of years due to declining per customer usage and year-to-year weather variations. The Company's four proposals are: (1) increase the monthly customer charge from $9.70 to $12.80; (2) implement its proposed volumetric rate design ('VRD'), a partial 'decoupling' mechanism that would separate revenue from gas sales; (3) implement a weather normalization adjustment provision ('WNAP'), a provision that would hold revenues at a constant rate between rate cases despite weather variations affecting usage; and (4) implement a revenue decoupling adjustment provision ('RDAP') either independently or in combination with the other rate design proposals.

Proposed Decoupling Mechanisms

[36-43] In the last Southwest Gas rate case, the Company proposed adoption of a 'decoupling mechanism' it called a Conservation Margin Tracker ('CMT') to address the Company's ongoing inability to achieve its authorized rate of return, due in part to declining per customer usage. A decoupling mechanism is intended to separate revenues from earnings on a per class basis and 'true-up' revenues through a surcharge or credit if the Company does not recover its baseline fixed costs in subsequent periods. In Decision No. 68487, the Commission declined to implement the CMT and indicated that 'the issue should be fully explored as part of usage volatility and margin recovery.' (*Id.* at 34.)The Commission directed Southwest Gas to 'coordinate its efforts to pursue implementation of a decoupling mechanism' through discussions with other stakeholders in the demand-side management ('DSM') policy process and in its next rate case. (*Id.*)

Southwest Gas

****24** The Company indicated that although it participated in the DSM collaborative process, no agreement was reached with RUCO or Staff regarding a supportable decoupling mechanism. Company witness Congdon stated that Southwest Gas attempted to address the concerns raised by RUCO in the collaborative process by proposing two separate tariffs - one to recover the non-gas portion of customer bills based on weather-adjusted volumes (WNAP) and the other to recover or refund differences between actual and weather-adjusted non-gas revenues (RDAP). (Ex. A-25 at 9-10.)

***491** For Southwest Gas, adoption of its proposed decoupling mechanisms is the most important issue in this case. The Company claims that its ongoing revenue instability is due primarily to two factors - declining usage per residential customer and variations in margin due to weather. Southwest Gas asserts that full revenue decoupling, through implementation of the RDAP and WNAP, would offer the following benefits: (1) removing the Company's inherent incentive to increase usage and discourage energy efficiency that exists under the current rate design structure; (2) increasing the savings potential for customers who would save more per therm the more they conserve; and (3) enabling Southwest Gas

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and the Commission to develop cost-effective energy efficiency programs without the risk of harm to the Company.

As described by Mr. Congdon, the RDAP is based on a program approved in Utah for Questar Gas Company. (Ex. A-24 at 5.) The RDAP would allow Southwest Gas to recover 'non-weather related dollar differences between actual and authorized non-gas revenue by recording monthly differences in non-gas revenue in a deferred account and recovering the balance annually through a rate adjustment (surcharge).'(*Id.*)The WNAP proposal is also based on the Questar Gas tariff, as well as a program approved in Oregon for Northwest Natural Gas.(*Id.* at 7.) Mr. Congdon described the WNAP as 'a tariff mechanism that removes weather-related volatility from the non-gas component of customer bills for each winter season billing cycle.'(*Id.*)

Southwest Gas contends that there is currently no mechanism in place that protects the Company and its customers from weather variations that deviate from weather normalized volumes used to establish rates in a rate case. According to Southwest Gas, the WNAP would protect the Company from warmer-than-normal weather variations and would protect customers from colder-than-normal variations. The Company also suggests that the RDAP should be implemented with the WNAP in order to isolate weather-related variations from non-weather related variations in margin recovery. At a minimum, the Company proposes that the WNAP and RDAP be implemented on a three-year pilot basis, or until the Company's next rate case, whichever occurs first, with a cap at the revenue amount necessary to yield the Company's authorized rate of return.

Southwest Gas argues that adoption of revenue decoupling would not transfer risk from the Company to customers, but would simply ensure that the Company could recover the amount of margin per customer authorized by the Commission. The Company claims that customer usage and weather variations are beyond its control and that, even with revenue decoupling, Southwest Gas would continue to be responsible for effectively managing its costs. With respect to its authorized return on equity, the Company asserts that no downward adjustment would be appropriate if revenue decoupling were implemented in this proceeding. According to the Company, the proxy companies used in its cost-of-capital analysis have some measure of revenue stabilization in place, and therefore, the proxy group baseline already incorporates a decoupling assumption.

AIC

****25** AIC supports the Company's WNAP and RDAP proposals. Dr. Daniel Hansen testified that the WNAP would reduce weather-related variations in the Company's revenues, while the RDAP would eliminate the Company's disincentive to support conservation and energy efficiency programs, preserve customer incentives to conserve, improve the Company's ability to attract capital at reasonable rates, and reduce regulatory effort and expenses. (AIC Ex. 2 at 2-3.)
AIC argues that LDCs such as Southwest Gas incur high fixed costs in serving customers, which costs do not vary significantly based on usage. According to Company witness Ralph Miller, 99 percent of Southwest Gas's ongoing non-gas costs are fixed, yet the current rate structure collects a majority of those costs through variable commodity charges. (Tr. at 629.) As a result, AIC asserts, less usage per customer or warmer-than-normal weather will ***492** result in Southwest Gas's being unable to recover its fixed costs regardless of the Company's efficiency in controlling costs.

AIC points out that Southwest Gas's credit ratings are only one step above 'junk' status according to Moody's and S&P, and that the Company has consistently been unable to earn its authorized return due to declining usage per customer. AIC contends that if the Company's credit ratings dip below junk status, access to capital will be more difficult and more costly and could ultimately harm customers. AIC also claims that at least 20 states have adopted some form of weather normalization adjustor and that the WNAP proposed by Southwest Gas is identical to the mechanism approved by the Utah Commission for Questar Gas. AIC asserts that such a mechanism would result in a more stable revenue stream for the Company and that, according to Company witness Congdon, had a WNAP been in effect over

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the last 10 years, Southwest Gas's customers would have paid $5.8 million less than they actually paid. (Ex. A-25 at ABC-1.)

According to Dr. Hansen, the surcharges or refunds that usually occur through a revenue decoupling mechanism are historically not large amounts. He points to Northwest Natural Gas in Oregon where, after the first adjustment, the following rate change was approximately 0.2 to 0.5 percent. (Tr. at 574.) AIC contends that the RDAP has the added benefit of producing gradualism in rates, which benefits the Company, ratepayers, and the Commission. Finally, AIC argues that implementation of the RDAP would remove the inherent disincentive for Southwest Gas to engage in energy efficiency programs. Dr. Hansen testified that DSM efforts by Questar Gas and Northwest Natural Gas improved noticeably after decoupling was adopted.

SWEEP

SWEEP fully supports implementation of the proposed WNAP and RDAP proposals as a means of encouraging a significant increase of DSM expenditures by Southwest Gas. SWEEP witness Jeff Schlegel testified that current DSM funding of $4.4 million should be increased to $12 million by 2010, with a ramp-up in spending in 2009. (SWEEP Ex. 1 at 2-3.) Mr. Schlegel indicated that implementation of revenue decoupling would remove the disincentive that currently exists for Southwest Gas to pursue cost-effective DSM and to support energy efficiency standards, building energy codes, and other measures that encourage reductions in energy usage. (*Id.* at 4.)

**26 SWEEP states that its objective is to decrease customer gas usage and save customers money. It contends that to achieve these objectives, DSM and energy efficiency efforts must reach more customers, and that support from the utility company is an important factor in those efforts. According to SWEEP, without decoupling, utilities like Southwest Gas only have an incentive to sell more gas in order to increase revenues.

Mr. Schlegel supports implementation of the WNAP and RDAP as three-year pilot programs, with annual tracking and evaluation at the end of the pilot. (SWEEP Ex. 2 at 3.) He claims that pilot implementation will assist in resolving the differences between the parties on the decoupling issue, by providing data regarding the programs. However, SWEEP believes that adoption of the decoupling programs should be conditioned on a substantial increase, to $12 million per year, in cost-effective DSM programs.

SWEEP also argues that implementation of the decoupling pilot should not be delayed by the Commission's recently opened generic investigation into regulatory and rate incentives for natural gas and electric companies (Docket Nos. G-00000C-08-0314 and E-00000J-08-0314). SWEEP asserts that the WNAP/RDAP pilot proposed in this case would provide useful, real-world information that could be reviewed as part of the generic investigation.

RUCO

RUCO argues that although Southwest Gas participated in collaborative efforts regarding rate design alternatives, no consensus was achieved with the participating stakeholders, including RUCO and Staff. RUCO contends *493 that the proposed RDAP differs little from the CMP rejected in the Company's last rate case because it would effectively provide South-west Gas a guaranteed method of recovering revenues.

RUCO asserts that a revenue decoupling tariff would require customers to pay for a level of gas service that they do not use and, citing the Company's last rate case Decision, 'could result in disincentives for such customers to undertake conservation efforts.' (Decision No. 68487 at 34.) RUCO disagrees with the Company's claim that the RDAP would encourage conservation and claims that the RDAP could be counterproductive to conservation efforts because customers that reduce their demand would receive diluted price signals. (RUCO Ex. 8 at 8.) RUCO argues that if the Commission's goal is to promote conservation, it should not adopt decoupling mechanisms that provide a guaranteed level of revenue recovery.

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RUCO also claims that the RDAP should be rejected because declining usage is a normal risk faced by utility companies. According to Mr. Rigsby, a number of variables exist between rate cases including customer growth, inflation, weather, and interest rates. (*Id.* at 5.) RUCO contends that regulatory lag between cases is common to all utilities and that lag may provide benefits that counter the detrimental effects of declining usage. RUCO claims that the proposed RDAP and WNAP are simply an attempt by Southwest Gas to shift shareholder risk to ratepayers and that the RDAP is a form of single-issue ratemaking that would be inconsistent with the holding of *Scates v. Arizona Corporation Commission*, 118 Ariz. 531 (Ariz. Ct. App. 1978). According to RUCO, adoption of the RDAP would expand the definition of a permissible automatic adjustment clause under *Scates* to include not only costs incurred by the Company, but also adjustments for specifically defined sales volumes.

**27 With respect to the WNAP specifically, RUCO points out that weather, like other variable components inherent in regulatory lag, is a risk faced by all utilities and that such fluctuations are reflected in stock prices and returns expected by investors. (RUCO Ex. 8 at 11-12.) As with the RDAP, RUCO contends that ratepayers would be required to pay for a level of gas service they do not receive, because the WNAP would be calculated for each customer, during each winter billing cycle, to reflect the difference between the customer's actual usage and usage assuming normal weather. RUCO points out that the Company's rate case revenues are annualized over a ten-year period to smooth out year-to-year fluctuation and determine a weather normalized amount of revenues.

Staff

Staff opposes the Company's decoupling proposals for many of the same reasons described by RUCO. Staff argues that the RDAP and WNAP would together achieve the same result as the CMT proposed by Southwest Gas in its last rate case (*i.e.*, to ensure a guaranteed stream to offset declining usage caused by many factors).

Staff witness Frank Radigan testified that 'the only thing the Company wants to achieve through its proposed rate design is avoidance of financial risk, nothing more nothing less.' (Ex. S-11 at 4.) According to Mr. Radigan, the Company's various rate design proposals would result in shifting almost all shareholder risk onto ratepayers. He indicated that the Commission is obligated only to allow the Company an opportunity to earn a reasonable return, not a guarantee. (*Id.*)

Staff also contends that adoption of the proposed decoupling mechanisms is premature because the Company's DSM programs are relatively new, and the $4.4 million budget authorized through a DSM surcharge in the last rate case has not yet been reached. In addition, Staff witness Robert Gray stated that the Commission recently opened a generic docket to evaluate regulatory and rate incentives for both gas and electric companies, which could encompass consideration of decoupling mechanisms. (Tr. at 966-67.) Mr. Gray testified that the generic docket was initiated in response to a letter by Commissioner Mundell asking Staff to look into alignment of utility incentives with energy-efficient investments. (*Id.*) Mr. Gray also **494 pointed to the Energy Independence and Security Act of 2007, through which Congress directed states to look into rate designs that encourage energy efficiency, as a reason for allowing the Commission to evaluate revenue decoupling on a generic basis.(*Id.*)

With respect to the conservation benefits touted by Southwest Gas, Staff claims the Company has not demonstrated that lack of decoupling has impeded its DSM efforts. Staff contends that the Company's decoupling proposals are overly broad with respect to the definition of conservation because, as described by Mr. Radigan, declining usage could be related to economic downturns, changes in customer conditions, collapse of the housing market, and other factors. (Tr. at 871.)

**28 Staff also asserts that Southwest Gas has not demonstrated that a traditional rate design jeopardizes its ability to earn its authorized return. Staff claims that the Company did not isolate and exclude important variables, such as choice differences between old and new customers, and did not demonstrate that declining aver-

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age usage threatens the Company's revenues under traditional rate design methods. According to Staff, it was this type of information the Commission indicated it was seeking when it stated in the last rate case that '[t]here is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future.' (Decision No. 68487 at 34.)

Staff also expressed concern with the effect of the proposed decoupling mechanisms on low-income and low-usage customers, who may be required to pay more through fixed costs, with little or no ability to save through reduced usage. With respect to the risk factor, Staff argues that the shift of risk from shareholders to ratepayers, if decoupling were to be adopted, would necessitate a downward adjustment to the authorized return on equity. Finally, Staff claims that it is unclear what changes would need to be made to the Company's purchased gas adjustor ('PGA') mechanism if the decoupling proposals were adopted.

Resolution

We are not persuaded that the decoupling mechanisms proposed by Southwest Gas in this proceeding should be adopted. Both Staff and RUCO have raised valid concerns regarding the Company's proposals, and we believe that consideration of revenue decoupling through the pending generic docket is the appropriate method of addressing those issues. As indicated in the Company's last rate case, '[decoupling mechanisms] should be fully explored as part of a broader investigation of usage volatility and margin recovery.' (Decision No. 68487 at 34.)

We remain concerned that the decoupling proposals could provide a disincentive to customers to undertake conservation efforts, because they would be required to pay for gas they did not use. It appears that, first and foremost, revenue decoupling is a means of providing the Company with what is effectively a guaranteed method of recovering authorized revenues, thereby shifting a significant portion of the Company's risk to ratepayers.

Although we appreciate that SWEEP and AIC support revenue decoupling as a means of providing substantial increases to Southwest Gas's DSM budget, the generic docket will provide an opportunity to evaluate a number of potentially viable energy efficiency alternatives in addition to revenue decoupling. We expect the generic docket will enable stakeholders to bring forth a comprehensive array of options that could be employed by gas and electric companies to encourage greater participation in efficiency programs, while minimizing the rate impact on participating and non-participating customers alike.

We expect that the consideration of decoupling mechanisms and other related rate design proposals within the pending generic docket will also include an Integrated Resource Planning ('IRP') process to better enable the Commission and affected stakeholders to review capacity additions, energy efficiency programs, and decoupling measures in a comprehensive manner. Staff should continue to take comments and conduct workshops to ensure that all relevant factors are considered prior to making recommendations***495** with respect to the generic docket.

****29** However, we believe Southwest Gas has raised valid 'potential' customer benefits and savings associated with full revenue decoupling. Therefore, we would like the full revenue decoupling mechanisms proposed by Southwest Gas in this proceeding to be more thoroughly and precisely evaluated for Commission consideration. In order to accomplish this and provide the Commission with as much empirical (as opposed to speculative or theoretical) information as possible before imposing such mechanisms that have only a 'potential' for customer benefits and savings, we will require Southwest Gas to submit data based on Southwest Gas' historical usage. We will require Southwest Gas to submit a report showing exactly how the full revenue decoupling mechanisms proposed in this case would have affected customers if the mechanisms had been in effect for the historical period covering January 1, 2003, through December 31, 2008. AS a compliance item in this docket, we will require Southwest Gas to submit a report no later than April 3, 2009, containing the fol-

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lowing information:

1. The amount of the monthly bill for the average residential customer in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

2. The amount of the monthly bill for the median residential customer in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

3. The amount of the monthly bill for the residential customer using twice the average in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

4. The amount of the monthly bill for the residential customer using twice the median in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

5. The amount of the monthly bill for the residential customer using fifty percent (50%) of the average in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

6. The amount of the monthly bill for the residential customer using fifty percent (50%) of the median in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

7. A detail of all the benefits, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

8. A detail of all the savings, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

9. A detail of all the detriments, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

**30 10. A detail of all the costs, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

11. Any other full revenue decoupling data that Southwest Gas believes would be beneficial to the Commission in adequately and properly assessing Southwest Gas' proposed full revenue decoupling mechanisms.

Volumetric Rate Design

[44] In the event the Commission rejects its RDAP and WNAP proposals, Southwest Gas requests that an alternative volumetric rate design ('VRD') be adopted. Under the VRD proposal, smaller users would pay a greater percentage of non-gas costs and a smaller percentage of gas costs than under traditional rate design. Larger users, on the other hand, would pay a smaller percentage of non-gas costs and a ***496** greater percentage of gas costs. The Company claims that the VRD is a form of revenue decoupling and reflects a more accurate cost-based rate design. Company witness Congdon indicated that the VRD is revenue neutral to customers because it has the same effective rate per therm for all gas consumed compared to a traditional rate design. (Ex. A-26 at 4.)

As described by RUCO witness Marylee Diaz Cortez, the VRD would include 'a higher than normal non-gas commodity charge in the first tier and a $0.00 non-gas commodity charge in the second tier.' (RUCO Ex. 2 at 10.) Ms. Diaz Cortez disputes the Company's claim that this rate design proposal is revenue neutral to customers stating that it would shift a portion of non-gas costs from large users to small users. (*Id.* at 11.)RUCO claims that the VRD would cause customers with less than 55 therms of usage to pay more than under a traditional rate design and that the Company would be guaranteed a level of revenue recovery from the lower usage blocks. RUCO asserts that the VRD is simply a different method of guaranteeing the Company revenue recovery due to declining usage. (*Id.*)

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Staff also opposes adoption of the Company's VRD proposal for the same reasons it objects to the RDAP and WNAP. Staff witness Radigan testified that the Company's proposed rate design would flatten rates charged to customers, by allocating recovery of revenue between rate blocks of the commodity charge and gas cost, but not the overall rate collected by the Company. Mr. Radigan states that, contrary to the Company's claim that the VRD would encourage conservation, the real goal is full margin recovery. According to Mr. Radigan, Southwest Gas currently collects 80 percent of its margin through the customer charge and the first block of the commodity charge. Under the VRD proposal, however, he claims that the Company would collect 100 percent of margin costs through the customer charge and first tier commodity block, thereby removing any ability by customers with lower usage to benefit by conservation efforts. (Ex. S-10 at 5-7.)

We agree with Staff and RUCO that the VRD proposed by Southwest Gas is simply an alternative method of enabling the Company to collect more of its margin costs through a shifting of risk from the Company to ratepayers. Although the Company's stated intent with the VRD is to encourage conservation efforts by sending better price signals to customers, as Staff points out the VRD would have the opposite effect by removing the ability of customers to reduce their bills through decreased usage. For lower use customers, the variable commodity charge would have a lesser effect on overall bills, and for customers with usage solely in the first tier there would be virtually no incentive to reduce usage. We therefore decline to adopt the Company's proposed volumetric rate design.

Basic Service Charge

Southwest Gas

**31 [45-52] In the event that the Commission does not adopt its decoupling rate design tariffs, Southwest Gas witness Congdon proposes that the Commission adopt an increase in the residential single-family basic monthly service charge from the current $9.70 to $12.80, as well as increases for the basic monthly charge for other customer classes, as a means of allowing the Company to recover a larger percentage of its fixed costs through the basic monthly service fee. (Ex. A-24 at 9.) Mr. Congdon stated that the current monthly charge recovers approximately 40 percent of the Company's fixed costs, with the balance recovered through commodity charges. He indicated that the proposed increase would enable Southwest Gas to increase its recovery of fixed costs through the customer charge to approximately 45 percent. (*Id.*)

The Company opposes the more modest customer charge increases proposed by Staff and RUCO, which would raise the fixed monthly charge to $10.70 and $11.52, respectively. Southwest Gas contends that adoption of these smaller increases would not address the ongoing problem related to declining per customer consumption because too much of the Company's revenues would remain tied to commodity charges. According to Company witness *497 James Cattanach, usage per residential customer has declined from 332 therms during the test year to 319 therms as of March 31, 2008. (Ex. A-22 at 3.) Mr. Congdon testified that if the rates approved in this case are based on the test year usage per customer, rather than the lower usage after the test year, Southwest Gas would experience an immediate annual revenue shortfall of $6.7 million. (Ex. A-25 at 16-17.)

Southwest Gas argues that even if the Commission adopts its proposed $12.80 per month customer charge, the Company still needs approval of rate design measures that separate revenues from weather fluctuations and declining usage. Otherwise, according to the Company, it will continue to experience an inability to earn its authorized return on a going-forward basis. However, the Company claims that if the Commission grants full revenue decoupling, it would not be opposed to a smaller customer charge increase or retaining the customer charge at its current level.

SWEEP

SWEEP opposes any increase to the monthly customer charge, but supports full revenue decoupling for Southwest Gas. SWEEP witness Jeff Schlegel testified that

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SWEEP opposes higher fixed charges because an increase to fixed charges (*i.e.*, the monthly service charge) would reduce the price signal customers receive from reducing their energy usage and becoming more efficient. (SWEEP Ex. 1 at 6; SWEEP Ex. 2 at 4.)

RUCO

RUCO does not dispute that Southwest Gas is experiencing declining per customer usage, but believes the situation is not as dire as suggested by the Company. Mr. Rigsby stated that utilities operate in a dynamic environment in which there is constant fluctuation in revenues and expenses between rate cases. He points out that during these interim periods, utility companies may see inflation, increased revenues due to customer growth, decreased revenues due to warmer weather or declining usage per customer, returns that may increase or decrease due to plant additions and depreciation, and changes in interest rates. (RUCO Ex. 8 at 5-6.) Mr. Rigsby testified that RUCO's proposed rate design would mirror the Company's current rate design except for allowing slightly more revenues to be recovered through the fixed monthly charge rather than variable commodity charges. (*Id.* at 13-14.)RUCO asserts that its rate design would allow the Company to recover more of its fixed costs and that it therefore is a better alternative than Southwest Gas's various decoupling mechanisms.

Staff

****32** With respect to the single-family residential monthly customer charge, Staff witness Frank Radigan recommends increasing the customer charge by approximately 10 percent, from $9.70 to $10.70 per month. (Ex. S-10 at 9-10.) The multi-family residential customer charge would also be increased by $1.00 per month, from $8.70 to $9.70, and low-income customers' customer charge would be increased from $7.00 to $7.50 per month. Mr. Radigan's rate design methodology was intended to minimize rate shock concerns by employing a two-step process. The first step of Staff's revenue allocation was to bring the rate of return for each class within 10 percent of the overall rate of return, while the second step would mitigate the increase to be borne by any individual class by limiting each class increase to no more than one percent of the overall increase. (*Id.* at 3-4.)

Staff disagrees with the Company regarding the proper allocation of revenues between various customer classes. Staff witness Radigan contends that the Company's proposed allocation methodology, which is intended to bring the rate of return for classes closer to the overall rate of return, was not applied in a consistent manner. Staff asserts that its proposed rate design is consistent with the Decision in the last Southwest Gas rate case, in which the Commission stated its goal of using rate designs that follow cost of service principles and encourage gradualism, fairness, and conservation. (Decision No. 68487 at 38.) According to Mr. Radigan, ***498** Staff's recommended rate design would eliminate the declining block rate structure so as to encourage conservation, while at the same time avoiding large increases to the fixed customer charge which could send an improper price signal that discourages conservation.(*Id.*)

Resolution

We agree with Staff's rate design recommendation because it balances the objectives of allowing Southwest Gas to continue to recover more of its fixed costs through the customer charge while, at the same time, minimizing the burden on any individual rate class. We also agree with Staff's proposal to flatten the volumetric charge into a single rate for all usage, rather than continuing the current declining block rate structure. As Staff's witness stated, eliminating the declining rate block structure will send customers price signals that are more appropriate and should encourage greater conservation efforts.

Although the Company contends that Staff's recommendation fails to allow recovery of fixed costs through the fixed customer charge, we believe the approximately 10 percent increase of the monthly residential customer charge (from $9.70 to $10.70) provides adequate

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movement in the direction of fixed cost recovery. The Company's proposed 32-percent increase in the residential customer charge would diminish the ability of many customers to control their gas bills by engaging in conservation and would undermine the gradualism concept in setting rates. As we stated in the Company's last rate case, '[w]e agree with all parties that movement closer to cost-based rates is in principle a laudable goal. However, that goal must be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation. ' (Decision No. 68487 at 38.)

**33 We will therefore adopt Staff's recommended customer charges for all customer classes and volumetric commodity charges commensurate with Staff's rate design, as modified by the revenue requirement adopted hereinabove. For rate class G-5 (single-family residential), the basic monthly charge will be set at $10.70 per month with a single block commodity base rate of $0.57070 per therm. For rate class G-6 (multi-family residential), the basic monthly charge will be increased to $9.70 per month with a commodity base rate of $0.55343 per therm. Low-income-customer basic monthly charges will increase to $7.50 with the same $0.55343 commodity base rate.

Based on the rate design adopted in this case, residential customers in the G-5 rate class with average summer monthly usage of 16 therms would experience an overall monthly increase of $1.46, from $33.36 to $34.82 (4.38 percent). [FN9] G-5 rate class customers with average winter usage of 56 therms per month would see an overall monthly increase of $3.47, from $91.66 to $95.13 (3.79 percent). Multi-family residential customers (G-6) with average summer usage of 12 therms would experience an overall monthly increase of $1.13, from $26.45 to $27.58 (4.27 percent). G-6 customers with average winter usage of 30 therms per month would experience a monthly increase of $1.34, from $53.07 to $54.41 (2.52 percent).

For small general service commercial customers (G-25S), average winter usage of 39 therms would increase monthly customer bills by $2.83, from $83.45 to $86.28 (3.39 percent). For medium general service commercial customers (G-25M), average winter usage of 315 therms would increase monthly customer bills by $6.24, from $451.94 to $458.18 (1.38 percent). For large general service commercial customers (G-25L), average winter usage of 2,220 therms would increase monthly customer bills by $56.58, from $2,823.16 to $2,879.74 (2.00 percent). Other rate classes would experience varying percentage increases depending on the time of year and individual customer usage.

MISCELLANEOUS ISSUES

Demand-Side Management

[53] In the Company's last rate case, the Commission authorized $4.4 million for Commission-approved energy efficiency and DSM programs, to be collected through a DSM *499 surcharge and held and disbursed through a balancing account. (Decision No. 68487 at 61-63.) Southwest Gas claims that it did not request an increase to the current DSM budget because it is continuing to ramp up its DSM programs, and has not received Commission approval to spend the entire authorized amount. The Company also asserts that absent approval of revenue decoupling, it would be unfair to increase Southwest Gas's energy efficiency and DSM obligations because additional declines in usage could exacerbate the Company's financial situation. The Company states in its brief that it is willing to investigate and pursue aggressive promotion of DSM if the Commission grants full revenue decoupling. The Company also attached to its brief a plan of action for pursuing additional DSM, but only on the condition that decoupling is approved. (SW Gas Initial Brief at 74-77.)

**34 As described above, SWEEP witness Jeff Schlegel advocates an increase in the Company's DSM budget to $12 million annually. Although SWEEP supports the Company's decoupling proposals, Mr. Schlegel recommends the DSM budget increase regardless of the Commission's adoption of decoupling. (SWEEP Ex. 1 at 5.)

Staff does not support SWEEP's proposal to increase the Company's DSM budget to $12 million, but does recommend an increase in the current $4.4 million budget. Staff witness Phillip Teumim testified that a reasonable

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approach would be to increase the DSM budget by $1 million per year for the years 2010 through 2012. He stated that this recommended increase would allow for continuing analysis of the existing programs, modifications if necessary, and reasonable development of new programs. (Ex. S-6 at 3-4.) Mr. Teumim points out that Southwest Gas's DSM budget has increased from $750,000 to over $3 million since 2006, but that the data collected by the Company does not provide a payback period for the programs and utilizes a cost-benefit analysis premised on the ratio between total resource costs and lifetime energy savings. He recommends that the Company be required to record and report estimated and actual dollar benefit analyses and payback periods and to segregate direct cost and benefit information. (Ex. S-5 at 12-13.) However, Staff's recommendation would apply only to new DSM measures and not to existing Energy Star Home and Low-Income Energy Conservation Programs. (*Id.* at 14.)

We agree with Staff's recommendations regarding the appropriate level of Southwest Gas's DSM budget. As the Staff witness stated, the Company's DSM programs are still in a startup phase, with full implementation and evaluation expected at the end of 2008. Since the 2008 budget was just over $3 million, it is reasonable to assume that the current $4.4 million will be achieved in 2009 and that additional $1 million incremental increases for the following three years will provide a reasonable level of DSM revenues over that period of time. We also agree with Staff that Southwest Gas should adopt the data collection and reporting requirements recommended by the Staff witness for new DSM programs.*Gas Pipeline and Procurement Issues*

Interstate Pipeline Capacity Portfolio

[54] Staff witness Stephen Thumb conducted an analysis of Southwest Gas's interstate pipeline capacity portfolio, the Company's management of its pipeline capacity, and penalties incurred by the Company from September 2004 through April 2007. (Ex. S-3.) Based on his review, Mr. Thumb concluded:

1. The El Paso Natural Gas ('EPNG') pipeline tariff (*i.e.*, EPNG tariff effective January 1, 2006, subject to revision) enacted during this time frame represented a total and complete restructuring of interstate pipeline services for Southwest Gas.

2. As a result of this new EPNG tariff, the annual fixed charges paid by Southwest Gas for interstate pipeline capacity increased appreciably.

****35** 3. Southwest Gas, under this new EPNG tariff, did incur additional charges and penalties,***500** but ...these additional charges and penalties [appear] to have been reasonable.

4. Southwest Gas is attempting to diversify its interstate pipeline capacity portfolio and Southwest Gas should continue seeking access to storage capacity, particularly market-area storage capacity. Concerning the latter, it is suggested that the Commission may want to consider taking an active role in promoting the development of market-area storage in Arizona.

5. Additionally, Southwest Gas should increase the documentation and requirements for its transportation-only customers. Also, Southwest Gas should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity.

(*Id.* at 2-3.)

Through the testimony of Company witness William Moody, Southwest Gas accepted all of Mr. Thumb's recommendations. (Ex. A-6 at 2.) As a result, there is no remaining dispute regarding this issue, and we direct the Company to abide by Staff's recommendations.

Gas Procurement Policies, Practices, and Procedures

[55] Staff witness Rita Beale conducted an evaluation of Southwest Gas's gas procurement strategies, prices, policies, and procedures and performed audits of the Company's monthly bank balance statements. Based on her analysis, Ms. Beale concluded that Southwest Gas's supply strategies and transactions were prudent and effective at stabilizing supply and price and reducing price volatility. (Ex. S-1 at 3.) She also indicated that

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the premium paid to EPNG was prudent in the context of the changes to the EPNG tariff and that such penalties are unlikely to be repeated in the future. Ms. Beale concluded that Southwest Gas did a good job of following its policies and procedures, but made the following total of ten management recommendations related to the Company's policies, practices, procedures, and gas supply transactions:

1. Consolidate all strategies, policies, and procedures into a minimal number of official company documents with sufficient detail such that new employees could read them and immediately perform the bulk of their work.

2. Clarify the APSP [Southwest Gas's Arizona Price Stabilization Plan] supply element by documenting expected volumes and timing for the next one to two years forward.

3. Clarify the precise nature of the APSP strategy. Is it a programmatic hedge, a judgmental hedge, or a hybrid of the two? The precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC oversight.

4. Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures.

5. Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies and the potential consequences, should be reevaluated, and then explicitly documented in official policies and procedures.

**36 6. Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates.

7. Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to authorized signature.

8. Considerably shorten the time lapsed between deal execution and deal confirmation with gas suppliers.

9. Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.

10. Update old master supply agreements that limit the buyers' liquidated damages at 50 cents per mmBtu into supply ***501** agreements that are based on true-up to actual market during non-performance.

(*Id.* at 6-7.)

At the time of the hearing, Southwest Gas accepted all but two of Ms. Beale's recommendations, numbers (1) and (4) listed above. (Ex. A-6 at 2.) At the hearing, Ms. Beale proposed a modification to her first recommendation, which would require the Company to compile a listing of its gas procurement policies, practices, and strategies indicating the names, ownership, and location of documents. (Tr. at 665.) In its brief, Southwest Gas states that it does not oppose this modified recommendation. (SW Gas Initial Brief at 68.)

The only remaining issue in dispute is Staff's recommendation that the *Arizona Dispatch Guidelines* be designated as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures. Company witness Moody stated that Southwest Gas opposes this recommendation because the Company uses a 'system generated report from its Gas Transaction System to produce a daily/monthly economic dispatch list of available contracts ... .[and] 'Gas Day' provides a system generated daily load forecast multiple times a day to identify load limits.' (Ex. A-6 at 5.) Mr. Moody indicated that Staff's recommendation is unnecessary because its current documents are used for the same purpose that Ms. Beale suggested for the *Arizona Dispatch Guidelines*. (*Id.*) At the hearing, Ms. Beale testified that the alternative document used by Southwest Gas is insufficient because it is 'not a limits and control document.' (Tr. at 666.) However, in its brief, Staff proposes a 'revised recommendation (4) that would require the Company to create

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a new limits and control document that would be in line with industry best practices.' (Staff Initial Brief at 48.) It is not clear whether Southwest Gas is in agreement with this latest revised Staff recommendation, but it appears to be a reasonable compromise of the positions taken by Staff and the Company as of the date of the hearing.

We will therefore adopt Staff's recommendations, as modified in accordance with the discussion above. With respect to the final disputed issue, Southwest Gas should develop, within 60 days from the effective date of this Decision, in a form acceptable to Staff, a new limits and control document that would be in line with industry best practices.

Line Extension Policy and Hookup Fees

**37 [56] The Company's current line extension policy allows a certain distance of 'free footage' before assessing a new customer for the additional mains and service lines necessary to connect the customer to the system. Staff witness Phillip Teumim explained that 'line extension fees' are intended to compensate utilities for costs of extending mains and service lines to customers beyond a free footage allowance, whereas 'hookup fees' are intended to compensate utilities for all other costs of connecting a new customer, other than specific main and service line costs, where the incremental cost of the new customer exceeds the embedded cost of existing customers. (Ex. S-5 at 2.)

Mr. Teumim stated that under 'Rule 6' of the Company's tariff, the allowable investment in line extensions is determined based on the following criteria: (1) application of an Incremental Contribution Model ('ICM'); (2) the customer must provide a return equal to the Company's allowed rate of return; and (3) the customer must pay for additional amounts. (Ex. S-5 at 7.) He indicated that '[c]onceptually, this is a reasonable methodology,' but stated that because the ICM and Rule 6 of the tariff have not been evaluated for a substantial period of time, Southwest Gas should be required in its next rate case to file 'an explanation, with sample calculations, of how it has been implementing those tariff provisions.' (*Id.* at 8.) He also indicated that the pending generic hookup fee docket (Docket Nos. E-00000K-07-0052 and G-00000E-07-0052) may generate useful information on this issue. (*Id.*)

Company witness Robert Mashas responded with Rebuttal Testimony that explained ***502** the Company's line extension policy and stated that no party expressed concerns with the Company's policies when Southwest Gas provided testimony and documentation regarding the line extension policies in its last rate case. (Ex. A-16 at 17-25.) He also described the mechanics of the ICM and how the Company incorporates its most recent cost data. (*Id.* at 20-23.)In his Rejoinder Testimony, Mr. Mashas indicated that any changes to the Company's line extension policy that may result from the generic hookup fee docket will be incorporated into its tariff and that Southwest Gas is willing to meet with Staff on an informal basis at any time to explain the line extension policy. (Ex. A-17 at 1516.) The Company contends that because this is the third consecutive rate case in which its line extension policies have been analyzed, Staff's recommendation on this issue is unnecessary and should be rejected.

We believe Staff's recommendation is reasonable and should be adopted. Although the Company's offer to meet with Staff on a informal basis regarding the tariff is commendable, it does not alter the underlying concern expressed by the Staff witness that the Company has not submitted the Rule 6 portion of its tariff for Staff or Commission review in nearly 10 years, despite the Company's indication that it has made significant changes to the ICM during that period. We therefore direct Southwest Gas, in its next rate case application, to provide an explanation, with sample calculations and documentation, of how it has been implementing the ICM and Rule 6 tariff provisions.

Purchased Gas Adjustor Mechanism

**38 [57-59] Southwest Gas's PGA mechanism was initially implemented in 1999, following a period of relative price stability in the natural gas markets. Subsequently, gas prices became much more volatile, which

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has created difficulties in determining the best, most equitable means of flowing through to ratepayers the rising gas costs incurred by utilities.

Staff witness Robert Gray explained that, as currently configured, the Company's PGA bandwidth of $0.13 per therm limits the movement of the monthly PGA rate over a 12-month period. This means that when the new PGA rate is calculated each month, the new rate may not be more than $0.13 different than the monthly PGA rate in any of the prior 12 months. (Ex. S-15 at 1-2.)

In the last Southwest Gas rate case, the Commission expanded the bandwidth from $0.10 to $0.13 per therm, increased the PGA 'trigger level' (the amount to be carried by the Company in the PGA bank balance before collection is triggered) from $22.4 million to $29.2 million, and set the base cost of gas at zero. (Decision No. 68487 at 51-55.) In a more recent case involving UNS Gas, the Commission increased that company's PGA bandwidth to $0.15 per therm, finding that the 50 percent increase balanced appropriately the interests of UNS Gas and its customers. (Decision No. 70011 at 81-82.)

In this case, Southwest Gas proposed to increase the PGA bandwidth to $0.24 per therm. According to Company witness Frank Maglietti, the proposed increase would set the bandwidth limit, as a percent of market gas prices, at the same level established in 1999 of $0.07 per therm. (Ex. A-18 at 6-7.) Southwest Gas contends that increasing the bandwidth to $0.24 would allow the PGA rate to more closely track the natural gas market, would send more accurate price signals to customers, and would reduce the need for future surcharge rate adjustments. (*Id.*)

The Company also argues that its proposed bandwidth increase would not affect Commission oversight of the PGA because the Company is obligated to file monthly gas purchase information and an annual report. Southwest Gas claims that it is also subjected to regular PGA reviews when the Commission evaluates the prudence of its gas purchases during rate case audits. (Ex. A-20 at 2.) The Company asserts that its bandwidth proposal promotes customer interests by smoothing out the peaks and valleys of the PGA bank balancing account, thereby reducing price volatility and sending customers more accurate price signals.(*Id.* at 3.)

***503** Staff witness Gray testified that although Staff understands the Company's desire for greater flexibility in the PGA bandwidth, Staff believes that an increase to $0.15 per therm would provide a reasonable balance of Company and customer interests and is consistent with the Commission's decision in the recent UNS Gas case. (Ex. S-15 at 5.)

Mr. Gray also recommended that the current PGA bank balance threshold for under-collected balances be eliminated. He explained that the threshold 'identifies the bank balance level, whether over-collected or under-collected, where [the Company] is required to take action at the Commission to either address the over- or under-collection, or explain why they should not do so at that given point in time.'(*Id.* at 6.) Mr. Gray stated that given the high and volatile natural gas prices that are likely to continue in the near future, it is appropriate to eliminate the PGA bank balance threshold for under-collected balances in order to allow the Company discretion to apply for a PGA surcharge, if warranted, and provide flexibility for the Company to avoid a surcharge if it believes changing market conditions do not require such a request. (*Id.* at 8-9.)

****39** Staff's final recommendation [FN10] regarding the Southwest Gas PGA is that the threshold on the PGA bank balance for over-collected balances be set at $55.78 million. Mr. Gray stated that the over-collection threshold for UNS Gas was recently set at $10 million, which represents a level of approximately $0.09 per therm based on 2006 gas sales volume for UNS Gas. He indicated that application of the same $0.09 per therm standard to gas sales for Southwest Gas results in an over-collection threshold of $55.78 million. (Ex. S-15 at 10.) Mr. Gray claims that an increase of the over-collection threshold to this level is reasonable, considering the Company's size and ongoing volatility in the gas markets. (*Id.*) Southwest Gas does not oppose Staff's recommendations regarding the PGA bank balance thresholds for either under- or over-collection. (Ex. A-19 at 4.)

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We find that Staff's recommendations regarding Southwest Gas's PGA should be implemented. With respect to increasing the bandwidth, we believe Staff's more modest proposal for an increase to $0.15 per therm provides recognition that additional flexibility is needed for the Company to respond to volatility in the gas markets, while at the same time insulating customers from drastic and sudden increases in gas prices. Southwest Gas's proposal to increase the bandwidth to $0.24 per therm could leave a number of customers exposed to an unacceptable level of automatic rate increases without any formal Commission review or approval. Staff's concurrent recommendation to eliminate the threshold for under-collected bank balances, and to increase the over-collection threshold to $55.78 million, are also reasonable measures that should be adopted. These measures will allow Southwest Gas greater flexibility in dealing with market volatility, while providing a measure of protection to customers from sudden price increases. Adoption of the Staff recommendations is also consistent with the PGA mechanism approved recently for UNS Gas. Accordingly, Staff's recommendations are approved.

SemStream Arizona (Service to Payson)

During the hearing, Commissioner Mayes questioned Southwest Gas regarding available options for extending natural gas infrastructure to the Payson area. Commissioner Mayes referred to a Staff Report regarding SemStream, Arizona, and asked whether Southwest Gas had investigated the possibility of serving the Payson area. (Tr. at 443.)

Southwest Gas recalled William Moody to the witness stand to respond to the Report. Mr. Moody indicated that the Company generally agreed with Section 7 of the Report and offered to update Staff with cost estimates for serving the Payson area. (Tr. at 1217.) Commissioner Mayes subsequently asked Company witness Roger Montgomery whether Southwest Gas would be willing to prepare a study regarding providing service to Payson. (Tr. at 1348.)

In its brief, Southwest Gas states that it is willing to submit, within 180 days from the Commission's Decision in this case, a study regarding the potential for extending service to ***504** the Payson area. The Company indicated that the potential provision of service to Payson would depend on the results of the study. (SW Gas Initial Brief at 74.)

****40** Given the Company's willingness to prepare and submit a study regarding providing service to the Payson area, we find that Southwest Gas shall file such a study or report within 180 days of the effective date of this Decision.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On August 31, 2007, Southwest Gas filed an application with the Commission for an increase in rates.

2. On September 25, 2007, Southwest Gas filed revised Supporting Schedule A-2 to its Application.

3. On October 1, 2007, the Commission's Utilities Division Staff filed a Sufficiency Letter, notifying the Company that its application met the sufficiency requirements and classifying Southwest Gas as a Class A utility.

4. By Procedural Order issued October 23, 2007, procedural timeframes were established and a hearing was scheduled to commence on June 16, 2008.

5. Intervention was granted to RUCO, Southwest Energy Efficiency Project, the Arizona Investment Council, and Mr. Banchy.

6. Southwest Gas filed Direct Testimony with its application on August 31, 2007.

7. Direct testimony was filed on March 28, 2008, by Staff, RUCO, AIC, and SWEEP. Additional Direct Testimony on rate design issues was filed by Staff and

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RUCO on April 11, 2008.

8. Rebuttal testimony was filed by Southwest Gas on May 9, 2008. Surrebuttal testimony was filed on May 27, 2008, by Staff, RUCO, and SWEEP. Rejoinder testimony was filed by the Company and AIC on June 9, 2008.

9. An evidentiary hearing was conducted at the Commission's offices in Phoenix, Arizona, commencing with public comment and opening statements on June 16, 2008, and concluding on June 26, 2008.

10. Initial Post-Hearing Briefs were filed on August 8, 2008, by Southwest Gas, Staff RUCO, AIC, and SWEEP. Southwest Gas filed an Erratum to its Initial Brief on August 18, 2008.

11. Reply Briefs were filed on August 22, 2008, by RUCO and SWEEP and on August 25, 2008, by Southwest Gas and Staff. Staff filed a substitute Reply Brief on August 28, 2008, that contained non-substantive corrections.

12. According to the Company's Final Schedules, in the test year Southwest Gas had adjusted operating income of $73,115,474 on an adjusted OCRB of $1,069,743,402.

13. In its Final Schedules, the Company calculated a revenue increase of $46,402,924, based on an OCRB of $1,069,743,402 and a rate of return of 9.45 percent. In its Final Schedules, the Company proposed FVRB of $1,392,895,487, and a FVROR of 7.74 percent, which would yield a revenue increase of $57,546,205.

14. Staff recommends a revenue increase of $28,376,480, based on an OCRB of $1,065,561,602 and a recommended rate of return on OCRB of 8.86 percent. Staff's FVRB recommendation of $1,388,713,687 and FVROR of 6.79 percent would yield a revenue increase of $28,239,870.

15. RUCO recommends an overall revenue increase of $32,046,846, based on an OCRB of $1,089,082,745 and an OCRB rate of return of 8.83 percent. RUCO's proposed FVRB of $1,463,404,389, with a FVROR of 6.57 percent, would yield the same revenue increase.

16. Of the $546,224 removed from rate base in this proceeding, the costs of expediting the Yuma Manors pipeline replacement ($320,779) should be permanently disallowed from inclusion in the Company's rate base.

17. For purposes of this proceeding, we determine that Southwest Gas has an Arizona FVRB of $1,389,259,911.

18. A rate of return on FVRB of 7.02 percent is reasonable and appropriate.

***505** 19. The position advocated by Southwest Gas and Staff with respect to recognizing 2008 wage increase expenses shall be adopted.

20. Staff's position regarding a reasonable allowance for AGA dues, and injuries and damages expenses shall be adopted.

21. The positions advocated by Staff and RUCO, to disallow 50 percent of MIP expenses, 100 percent of SIP expenses, and 100 percent of SERP incentives, are adopted.

22. With respect to RUCO's position that certain miscellaneous expenses should not be recovered through rates, 50 percent of RUCO's proposed disallowance is adopted.

23. Staff's proposed actual test year capital structure, consisting of 43.44 percent common equity, 4.48 percent preferred stock, and 52.08 percent long-term debt, is adopted. A 7.96 percent cost of long-term debt and 8.20 percent cost of preferred equity are also adopted, as is Staff's recommended 10.0 percent cost of common equity.

24. To establish a FVROR, Staff's alternative recommendation adjusting the weighted average cost of capital by applying an inflation-adjusted risk-free rate, reduced by approximately half, to the increment between the Company's OCRB and FVRB, is adopted. Assigning the applicable values to the actual capital structure produces a FVROR of 7.02 percent.

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25. Southwest Gas is entitled to a gross revenue increase of $33,533,844.

26. The Company's decoupling mechanism proposals are not adopted in this proceeding for the reasons set forth hereinabove.

27. The class responsibility for the revenue requirement shall be allocated using the methodology of Staff's rate design expert witness, Mr. Radigan.

28. For residential customers under Schedule G-5, the basic monthly customer charge should be increased from $9.70 to $10.70, and a single-tier rate design structure is appropriate in accordance with Staff's recommendation.

29. A separate multi-family residential basic monthly customer charge of $9.70 is appropriate under the new Schedule G-6 rate.

30. The low-income residential rate (G-10) should be increased slightly from $7.00 to $7.50 per month.

31. Staff's rate design recommendations for the other classes of customers, as set forth in its testimony and exhibits, are reasonable and shall be adopted.

32. The billing determinants proposed by the Company and Staff shall be employed for setting rates in this proceeding.

33. With respect to the Company's PGA mechanism, the current $0.13 per therm bandwidth shall be increased to $0.15 per therm, the threshold for under-collected bank balances shall be eliminated, and the over-collection threshold shall be increased to $55.78 million.

34. Southwest Gas shall, in its next rate case application, provide an explanation, with sample calculations and documentation, of how it has been implementing the ICM and Rule 6 tariff provisions regarding line extension policies.

35. Southwest Gas shall implement, within 60 days of the effective date of this Decision, Staff's Pipeline and Procurement recommendations, as described hereinabove.

36. Southwest Gas shall develop, within 60 days from the effective date of this Decision, in a form acceptable to Staff, a new limits and control document that would be in line with industry best practices in accordance with Staff's modified recommendation.

37. Southwest Gas's DSM budget shall be funded initially at the $4.4 million level recommended by Staff, with additional $1 million incremental increases for the years 2010 through 2012, and shall adopt the data collection and reporting requirements recommended by the Staff witness for new DSM programs.

****41** *CONCLUSIONS OF LAW*

1. Southwest Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251, and 40-367.

2. The Commission has jurisdiction over Southwest Gas and the subject matter of the Company's rate applica- tion.

3. The rates, charges, and conditions of service established herein are just and reasonable and in the public interest.

***506** *ORDER*

IT IS THEREFORE ORDERED that Southwest Gas Corporation is hereby authorized and, directed to file with the Commission, on or before December 31, 2008, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after December 1, 2008.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall notify its customers of the revised schedules or rates and charges authorized herein by means of

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an insert in its next regularly scheduled billing, in a form acceptable to Staff.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall, within 60 days of the effective date of this Decision, implement Staff's Pipeline and Procurement recommendations, as described hereinabove, and shall file in this docket as a Compliance Item a copy of the revised procedures.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall, within 60 days from the effective date of this Decision, develop in a form acceptable to Staff, a new limits and control document that would be in line with industry best practices, in accordance with Staff's modified recommendation, and shall file in this docket as a Compliance Item a copy of the revised procedures.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide an explanation, with sample calculations and documentation, of how it has been implementing its tariff provisions regarding line extensions.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall revise its Purchased Gas Adjuster mechanism to increase the PGA bandwidth to $0.15 per therm, to eliminate the threshold for under-collected bank balances, and to increase the over-collection threshold to $55.78 million. Within 10 days of the effective date of this Decision, the Company shall file as a Compliance Item in this docket, a revised PGA tariff consistent with the Decision.

IT IS FURTHER ORDERED that, as discussed hereinabove, of the $546,224 removed from rate base in this proceeding, the costs for expediting the Yuma Manors pipeline replacement project ($320,779) shall be permanently disallowed from inclusion in the Company's rate base.

IT IS FURTHER ORDERED that as a compliance item in this docket, Southwest Gas Corporation shall submit to Docket Control, by April 3, 2009, a report covering the period January 1, 2003, through December 31, 2008, and the report shall contain the following information:

**42 1. The amount of the monthly bill for the average residential customer in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

2. The amount of the monthly bill for the median residential customer in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

3. The amount of the monthly bill for the residential customer using twice the average in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

4. The amount of the monthly bill for the residential customer using twice the median in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

5. The amount of the monthly bill for the residential customer using fifty percent (50%) of the average in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

6. The amount of the monthly bill for the residential customer using fifty percent *507 (50%) of the median in each month with the full revenue decoupling proposals as compared to the actual bill with the rates approved in this decision.

7. A detail of all the benefits, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

8. A detail of all the savings, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

9. A detail of all the detriments, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

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10. A detail of all the costs, for each calendar year, that each customer class would have received with the full revenue decoupling proposals as compared with the rates approved in this decision.

11. Any other full revenue decoupling data that Southwest Gas believes would be beneficial to the Commission in adequately and properly assessing Southwest Gas' proposed full revenue decoupling mechanisms.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall fund its DSM budget initially at the $4.4 million level recommended by Staff, with additional $1 million incremental increases for the years 2010 through 2012, and shall adopt the data collection and reporting requirements recommended by the Staff witness for new DSM programs.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

FOOTNOTES

FN1 In its Reply Brief, Staff argues that the Commission should reject the Company's amended FVRB revenue requirement proposal because it is inconsistent with the Company's application - which requested a $50.2 million revenue increase based on a Fair Value Rate of Return ('FVROR') of 7.04 percent applied to the Company's proposed FVRB. (Staff Reply Brief at 22.) The FVROR issue is discussed below in the Cost of Capital section of the Order.

FN2 The $546,224 disallowance also requires a reduction to the Company's depreciation property tax expense.

FN3 *See UNS Gas, Inc* ., Decision No. 70011 (November 27, 2007) at 27; *Arizona Public Service Co.*, Decision No. 69663 (June 28, 2007) at 27; and *UNS Electric, Inc.*, Decision No. 70360 (May 27, 2008) at 21.

FN4 On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ('SIP'). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (*See* Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

FN5 *Federal Power Comm'n et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923).

FN6 Having reached this conclusion, however, as discussed below, we believe that Staff's alternative FVRB cost of capital, as modified, should be applied for purposes of calculating the Company's authorized fair value rate of return.

FN7 *Chaparral City Water Co. v. Arizona Corp. Comm'n* , 1 CA-CC 05-0002, Mem. Decision (Ariz. Ct. App. 2007)

FN8 Mr. Parcell explained that 'risk-free investments' are defined as U.S. Treasury Securities, with short-term maturities considered to be the risk-free rate. He used 4.5 percent as the risk-free rate for his calculation based on yields on such securities ranging from 2.0 percent for short-term to 4.5 percent for long-term Treasury Bonds. (*Id.* at 46.)

FN9 This overall increase, and the examples that follow, include an additional gas cost of $0.93689 per therm.

FN10 Staff also recommended that a revised PGA mechanism be submitted by Southwest Gas if the Commission were to adopt the Com-

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pany's decoupling proposals. Given our rejection of the decoupling mechanisms, it is not necessary to address this Staff recommendation.

**43 *508 EDITOR'S APPENDIX

PUR Citations in Text

[ARIZ.] Re Arizona Public Service Co., 258 PUR4th 353,Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827, Decision No. 69663, June 28, 2007.

[ARIZ.] Re Southwest Gas Corp., 213 PUR4th 53, Docket No. G-01551A-00-0309, Decision No. 64172, Oct. 30, 2001.

[ARIZ.] Re Southwest Gas Corp., 247 PUR4th 243, Docket No. G-01551A-04-0876, Decision No. 68487, Feb. 23, 2006.

[U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Viginia Pub. Service Commission, 262 U.S. 679, PUR1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675 (1923).

[U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281 (1944).

END OF DOCUMENT

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H

Washington Utilities and Transportation Commission
v.
Cascade Natural Gas Corporation
Docket No. UG-060256
Order No. 05

Washington Utilities and Transportation Commission
January 12, 2007

ORDER accepting a settlement that provides for a $7.061 million (2.7%) increase in the rates of a natural gas local distribution company (LDC). Commission conditions its acceptance of the settlement on the parties stipulating to an overall rate of return of 8.85%, which will provide a benchmark against which to measure any potential complaints regarding over-earning.

The LDC is authorized to implement a three-year pilot partial decoupling mechanism, subject to commission approval of a conservation plan that includes a cap on earnings and penalties for failure to meet conservation targets and benchmarks. The decoupling mechanism is intended to promote greater conservation efforts by breaking the link between fixed cost recovery and natural gas consumption.

The settlement reduces revenue requirement by $200,000 for non-core revenues gained by the LDC for gas management services and gas supply sales.

P.U.R. Headnote and Classification

1.
PROCEDURE

s31
Wa.U.T.C. 2007
[WASH.] Disposal of issues - Settlements - Standards for accepting - Consideration of merits of contested issues - Lawfulness and public interest of uncontested portions.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

2.
RATES

s650
Wa.U.T.C. 2007
[WASH.] Procedure - Disposal of issues - Settlements - Standards for accepting.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

3.
RATES

s373
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Revenue requirement adjustment - Authorized rate increase - Uncontested settlement provisions - Standard for accepting - Not contrary to law - In the public interest.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

4.
REVENUES

s2
Wa.U.T.C. 2007
[WASH.] Forecasts - Weather normalization - Natural gas local distribution company - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

5.
REVENUES

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s5
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Competitive services - Gas management services to non-core customers - Rate treatment - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

*195 6.
REVENUES

s5
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Competitive services - Gas supply sales - Rate treatment - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

7.
FINES AND PENALTIES

s5
Wa.U.T.C. 2007
[WASH.] Grounds for imposition - Violation of commission rules - Failure to file gas supply contracts - Natural gas local distribution company.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

8.
RATES

s308
Wa.U.T.C. 2007
[WASH.] Miscellaneous service charges - Disconnection and reconnection - Natural gas local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

9.
RATES

s378
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Miscellaneous service charges - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

10.
RATES

s125
Wa.U.T.C. 2007
[WASH.] Reasonableness - Ability to pay - Low-income assistance - Natural gas local distribution company - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

11.
EXPENSES

s19
Wa.U.T.C. 2007
[WASH.] Low-income assistance program - Annual funding - Inclusion in revenue requirement - Natural gas local distribution company - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

12.
RATES

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s373
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Revenue requirement spread - Local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

13.
RATES

s373
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

14.
RATES

s378
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Basic service charges - Local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

15.
RATES

s384
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Consolidation of transportation schedules - Local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

16.
RATES

s380
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Special factors - Treatment of lost and unaccounted for gas - Local distribution company - Stipulation.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

17.
RATES

s373
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Withdrawal of proposed infrastructure investment tracking mechanism - Discussion.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

18.
RATES

s235
Wa.U.T.C. 2007
[WASH.] Initiation of rate changes - Single-issue rate making - Withdrawal of proposed infrastructure investment tracking mechanism - Discussion.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

19.
RETURN

s26

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Wa.U.T.C. 2007
[WASH.] Reasonableness - Cost of capital - Natural gas local distribution company - Contested settlement - Grounds for approval.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

20.
RETURN

s44
Wa.U.T.C. 2007
[WASH.] Reasonableness - Cost of capital - Risk adjustment for decoupling - Natural gas local distribution company - Contested settlement - Grounds for approval.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

21.
RETURN

s92
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Contested settlement - Reasonableness.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

*196 22.
RETURN

s92
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Benchmark for overearnings - Settlement.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

23.
CONSERVATION

s1
Wa.U.T.C. 2007
[WASH.] Natural gas - Revenue decoupling pilot - Settlement - Conditions on approval - Earnings cap - Penalties for failure to meet conservation targets and benchmarks - Local distribution company.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

24.
GAS

s7
Wa.U.T.C. 2007
[WASH.] Demand-side management - Revenue decoupling pilot - Settlement - Conditions on approval - Earnings cap - Penalties for failure to meet conservation targets and benchmarks - Local distribution company.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

25.
REVENUES

s5
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Decoupling pilot - Promotion of conservation - Settlement - Conditions on approval - Earnings cap - Penalties for failure to meet conservation targets and benchmarks - Local distribution company.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

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26.
RATES

s380
Wa.U.T.C. 2007
[WASH.] Natural gas rate design - Decoupling pilot - Promotion of conservation - Settlement - Conditions on approval - Earnings cap - Penalties for failure to meet conservation targets and benchmarks - Local distribution company.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

27.
RETURN

s92
Wa.U.T.C. 2007
[WASH.] Natural gas local distribution company - Decoupling pilot - Avoiding windfall - Earnings cap.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

28.
PROCEDURE

s31
Wa.U.T.C. 2007
[WASH.] Disposal of issues - Settlements - Conditional acceptance.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

P.U.R. Headnote and Classification

29.
RATES

s650
Wa.U.T.C. 2007
[WASH.] Procedure - Disposal of issues - Settlements - Conditional acceptance.

Washington Utilities and Transportation Commission v Cascade Natural Gas Corporation

Before Sidran, chairman and Oshie and Jones, commissioners.

BY THE COMMISSION:

**1 *SUMMARY*

PROCEEDING . On February 14, 2006, Cascade Natural Gas Corporation (Cascade or the Company) filed revisions to its tariffs in Docket UG-060256 seeking to increase its annual revenues from Washington operations by $11.7 million, or about 4.5 percent. [FN1]The Washington Utilities and Transportation Commission (Commission) suspended the proposed tariffs by order entered on March 15, 2006, prior to the stated effective date of March 16, 2006.

The Commission convened a prehearing conference at Olympia, Washington on April 11, 2006, before Administrative Law Judge C. Robert Wallis. [FN2]The Commission conducted public comment hearings in Yakima, Washington on August 29, 2006, and in Bellingham, Washington on September 7, 2006. The Commission held a hearing on a multi-party, multi-issue settlement in Olympia, Washington, on October 12, 2006, before Chairman Mark H. Sidran, and Commissioners Patrick J. Oshie and Philip B. Jones, assisted by Administrative Law Judge Ann E. Rendahl. This order resolves all remaining contested issues.

PARTY REPRESENTATIVES. James Van Nostrand, Perkins Coie, LLP, Portland, Oregon, represents Cascade. Judith Krebs, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of the Attorney General (Public Counsel). Gregory J. Trautman, Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff). [FN3] Edward A. Finklea and Chad *197 M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represent the Northwest Industrial Gas Users

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(NWIGU). Nancy Glaser and Danielle Dixon, Seattle, Washington, represent the Northwest Energy Coalition (NWEC). Brad Purdy, attorney, Boise, Idaho, represents The Energy Project. John A. Cameron, attorney, Davis Wright Tremaine LLP, Portland, Oregon, represents Cost Management Services, Inc. (CMS). Scott Magie, project director, Longview, Washington, represents the Mint Farm Energy Center LLC. Vincent J. Diaz, Fox Island, Washington, represents the International Chemical Workers Union Council/UFCW Local 121-C.

COMMISSION DETERMINATION. The Commission suspended and set for hearing the rates Cascade initially proposed. After all parties had filed testimony and exhibits addressing Cascade's request, and just prior to hearing, the parties filed a multi-party, multi-issue settlement agreement (Settlement Agreement or Settlement) addressing all of the contested issues presented in Cascade's request for increased rates. In this Order, we accept the parties' proposed Settlement Agreement, subject to conditions, finding the Settlement results in rates that are fair, just, reasonable and sufficient.

We determine that the Settlement Agreement is consistent with the law and public interest, and is fully supported by the record evidence. We condition our acceptance of the Settlement on the parties stipulating to an overall rate of return of 8.85 percent for purposes of calculating the Company's cost of capital. While we accept the stipulated pilot program for decoupling in principle, we condition approval of the Company's Conservation Plan on the Plan including an earnings cap and penalties for the Company's failure to meet targets and benchmarks. We require Cascade to conduct an evaluation of the pilot decoupling proposal regardless of whether it seeks to continue the program after the three-year period expires. Finally, we accept the proposal for prospective treatment of gas management services revenues in paragraph 12(b)(ii), conditioned on the Company complying, within 30 days of the effective date of this Order, with statutory requirements to file tariffs and contracts with the Commission.

**2 Should the parties accept these conditions, we determine that Cascade should be authorized and required to file tariff rates in compliance with our decisions. The resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferen- tial.

MEMORANDUM

I. Background and Procedural History

On February 14, 2006, Cascade filed revisions to its currently effective Tariff WN U-3 for natural gas service. The proposed tariff revisions bore an effective date of March 16, 2006. Cascade proposed a general rate increase of $11.7 million or about 4.8 percent for its Washington operations. The Commission suspended the proposed tariff revisions by order entered on March 15, 2006, and set the matter for hearing.

Cascade serves approximately 235,000 customers in Washington and Oregon. The Company's Washington customers are located in three operational regions: Western, including the Kitsap Peninsula, Grays Harbor area, and Kelso/Longview; Northwest, including Bellingham, Mt. Vernon, and Oak Harbor/Anacortes; and Central, including Sunnyside, Wenatchee/ Moses Lake, Tri-Cities, Walla Walla, and Yakima.

In its filing, Cascade sought an overall rate of return of 9.37 percent, a rate of return on common equity of 11.15 percent, a capital structure with 50 percent common equity, a redesign of the Company's rates for transportation customers based on a proprietary cost-of-service study, new and modified fees and charges, and a number of adjustments to its revenue requirement. Cascade also proposed two regulatory mechanisms, a decoupling mechanism, referred to as the Conservation Alliance Plan, and a tracking mechanism, referred to as the Safety and Reliability Infrastructure Adjustment Mechanism (SRIAM), to adjust rates annually for investment in non-revenue producing pipeline infrastructure.

The Commission conducted a prehearing ***198** conference on April 11, 2006, before Administrative Law Judge Wallis. On April 13, 2006, the Commission entered two orders; Order 02, which granted various pending petitions to intervene, authorized formal dis-

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covery, and established a procedural schedule, and Order 03, a protective order. Administrative Law Judge Rendahl assumed responsibility as presiding officer in this proceeding during June 2006. The Commission held public comment hearings in Yakima and Bellingham, Washington during the evening hours of August 29 and September 7, 2006, respectively.

On August 15, 2006, Staff, Public Counsel, NWIGU, NWEC, The Energy Project and CMS filed response testimony. Only Staff addressed the Company's cost of capital and revenue requirement adjustments. Staff recommended a net decrease in revenue requirement of $321,588 after recognizing additional revenue from fees and charges. [FN4]Because the decrease was so small, Staff recommended the decrease in revenue requirement not be reflected in rates.

Staff, Public Counsel, NWIGU and NWEC objected to the Company's decoupling and infrastructure tracking mechanisms, as well as the Company's rate design and rate spread proposals. Staff and NWEC offered alternative decoupling proposals, and Staff and NWIGU proposed alternative proposals for rate design and rate spread. The Energy Project addressed the Company's proposal to increase funding of low-income assistance programs. CMS addressed its concerns about the Company's authority to sell natural gas to non-core, transportation-only customers at retail under tariff Schedules 663 and 664, issues CMS also raised in a separate complaint against Cascade in Docket UG-061256. [FN5]

**3 On September 12, the Company filed rebuttal testimony in which it concurred with NWIGU's position on rate design and rate spread and modified its SRIAM proposal, but did not modify its revenue requirement proposal. Staff, NWEC, Public Counsel and The Energy Project filed responsive and cross-rebuttal testimony addressing decoupling and low-income assistance programs.

On October 4, 2006, the Company and Staff filed a stipulation with the Commission reflecting their agreement on various revenue requirement issues. On October 5, the Company, Staff and NWIGU filed a stipulation reflecting their agreement on various rate spread and rate design issues.

After further discussion among all parties, on October 11 the parties filed a multi-party, multi-issue settlement addressing all of the contested issues in the rate case. The Settlement Agreement is attached to this Order as Appendix A. The Company, Staff and NWIGU agree in this Settlement to withdraw their October 4 and 5 stipulations. Public Counsel joined the Settlement Agreement, in part, but opposes the portions of the Settlement concerning cost of capital and the proposed decoupling mechanism.

The Commission conducted a hearing on the multi-party Settlement Agreement in Olympia, Washington on October 12, 2006, before Chairman Mark H. Sidran, Commissioner Patrick J. Oshie and Commissioner Philip B. Jones, assisted by Administrative Law Judge Rendahl. The Company, Staff, NWEC, NWIGU and Public Counsel presented witnesses in support of the Settlement Agreement. Public Counsel cross-examined witnesses concerning the contested decoupling proposal. Altogether, the record includes more than 350 exhibits, including the Settlement Agreement and a supporting Narrative Statement. Out of 197 comments that the Commission received from the public on Cascade's request for a rate increase, 193 were opposed to the increase. [FN6]

The parties filed Initial Briefs on November 15, 2006, and Reply Briefs on December 5, 2006. The Commission here enters its Final Order accepting the parties' multi-party Settlement Agreement subject to conditions, resolving the remaining disputed issues, and granting appropriate relief considering the full record of proceedings and the parties' arguments based on that record.

II. Discussion and Decisions

A. The Settlement Agreement

*199 On the eve of evidentiary hearings, the parties entered a multi-party, multi-issue settlement addressing all of the contested issues in this case, including:

- Various adjustments to the Company's revenue re-

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quirement

• Cost of capital

• Redesigned rates for transportation customers, based on NWIGU's cost-of-service study

• New and modified fees and charges

• Decoupling, and

• The Company's proposed infrastructure tracking mechanism, referred to as the SRIAM.

The Settlement is not a global agreement in which all of the parties agree on all of the issues. While Staff and the Company agree on revenue requirement issues and cost of capital, no other party joins them. Staff, the Company, Public Counsel, NWEC and the Energy Project agree on changes to miscellaneous service charges, basic charges, and funding for low-income assistance. Staff, the Company and NWIGU agree on rate spread and certain rate design provisions, and the Company agrees to withdraw its SRIAM proposal. While Staff and the Company agree on the overall cost of capital and the Company, Staff and NWEC agree on a partial, pilot decoupling program, Public Counsel contests those Settlement provisions pertaining to the decoupling mechanism and the cost of capital.

**4 *B. Standards for Accepting Settlement Agreements*

[1, 2] The Commission's procedural rules govern the process for reviewing and accepting settlements. First, the Commission 'may accept the proposed settlement, with or without conditions, or may reject it.' [FN7] The Commission must 'determine whether a proposed settlement meets all pertinent legal and policy standards.' [FN8] The Commission may approve settlements 'when doing so is lawful, when the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission.' [FN9]

In a decision accepting a settlement in a prior rate case, the Commission described this standard as 'a three-part inquiry':

(1) We ask whether any aspect of the proposal is contrary to law; (2) We ask whether any aspect of the proposal offends public policy; and (3) We ask if the evidence supports the proposed elements of the Settlement Agreement as a reasonable resolution of the issue(s) at hand. [FN10]

In that decision, the Commission noted that settlements 'are by nature compromises of more extreme positions that are supported by evidence and advocacy.' [FN11] The Commission further held that '[r]atemaking is not an exact science' and accepted the settlement on the basis that 'the overall result in terms of revenue requirement is reasonable and well supported by the evidence.' [FN12] Based on this decision, both Cascade and Staff request the Commission approve the proposed settlement in this proceeding. [FN13]

Thus, in reviewing the proposed Settlement, we must consider not only the merits of the contested issues - the decoupling proposal and resolution of cost of capital issues, but whether the uncontested portions of the Settlement are lawful, supported by the record and are in the public interest.

C. Uncontested Settlement Provisions

1. Revenue Requirement Adjustments

[3-7] In paragraph 12 of the Settlement Agreement, Staff and the Company agree to a revenue requirement increase for Cascade of $7,061,536, which would result in an overall 2.7 percent increase relative to current rates. The Settlement proposal reflects an approximately 40 percent decrease from the Company's original proposal. [FN14]Staff and the Company derived this amount by agreeing to the treatment of a number of contested restating and proforma adjustments. [FN15]

***200** Other than CMS's stipulation in paragraphs 12(b)(iii) and (iv) of the Settlement and Public Counsel's objection to the resolution of cost of capital issues in paragraph 12(a), no party other than Staff and the Company took a position or objected to the stipulations in paragraph 12 of the Settlement Agreement.

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In resolving an adjustment for weather normalization, Staff and Cascade stipulate to a margin adjustment of $730,779 to normalize test year temperatures to reach a revenue requirement number, but do not agree on a weather normalization methodology. [FN16]The weather normalization adjustment adjusts 'test period loads to normalize them to reflect the gas throughput volumes that would have occurred under 'normal' weather.' [FN17]

**5 One of the stipulated adjustments concerns the treatment of revenues and costs for Cascade's gas management services to non-core customers, *i.e.*, those taking transportation-only service. Cascade provides certain services to non-core customers on a competitive basis. These services include transportation, pipeline capacity, balancing, gas supply, and gas management services. Cascade sought to remove the revenues and expenses associated with these services, including gas supply sales, from the revenue requirement calculation, asserting the services are authorized exclusively under rules and orders of the Federal Energy Regulatory Commission (FERC). [FN18]

Staff contested the treatment of revenues Cascade earned for these services, arguing the revenues and costs should be included in the calculation of revenue requirement. [FN19]While Staff agreed that the services are competitive, Staff argued the services are provided under Cascade's tariff Schedule 687, which the Commission approved on condition that Cascade show in future rate cases that the services are not adverse to core customers. [FN20]

CMS, one of Cascade's competitors for gas supply services, requests the Commission order Cascade to remove language from tariff Schedules 663 and 664 that implies the Company may sell natural gas at retail under FERC regulations. [FN21]In a separate complaint in Docket UG-061256, CMS argues that Cascade is violating RCW 80.28 by selling natural gas at retail - the same sales at issue in the dispute over treatment of gas management services revenues and costs - without tariffs or special contracts on file with the Commission allowing it to do so. [FN22]CMS asserts that FERC regulations apply to sales for resale, not retail sales. [FN23]

CMS also asserts that Schedule 687, which addresses gas management services, does not govern sales of gas supply. [FN24]

In response, Cascade argues its gas supply sales are not subject to Commission jurisdiction, that the Company's shareholders bear the risk for these services and that the revenues and costs should remain below the line, or excluded from the revenue requirement calculation. [FN25]

In paragraph 12(b)(i) of the Settlement Agreement, Staff agrees to the Company's proposal to remove the revenues and costs of gas management services from the revenue requirement calculation, but Staff and the Company agree to include $200,000 of gas management service revenues in determining the Company's revenue requirement. The Company also agrees to share with customers 50 percent of the net margins the Company realizes on these services in the future. [FN26]In addition, CMS and the Company agree that Cascade will remove language from Schedules 663 and 664 referring to authority under FERC regulations for blanket marketing certificates, and agree to stipulated facts for purposes of the record in the complaint proceeding. [FN27]

Cascade expresses concern that if the Commission grants CMS' requests in Docket UG-061256, the gas supply sales would be deemed unauthorized, requiring rejection of the Settlement provisions to reduce revenue requirement by $200,000 and to provide for prospective sharing of net margins. [FN28]The Settlement Agreement is not contingent on resolving the complaint. The Company has agreed to certain terms and takes the risk of an adverse ruling on issues in the complaint.

6 Given Cascade's concern, our decision concerning this portion of the Settlement Agreement must begin with our decision in the complaint proceeding in Docket UG-061256.The facts and circumstances underlying our ***201 decision in that docket are set forth in detail in Order 03 therein, entered concurrently with this Order. There we find that Cascade relied improperly on FERC regulations for authority to make retail sales of gas, [FN29] and that Cascade's gas supply sales violate RCW 80.28.050, RCW 80.28.080 and WAC 480-80-143 by failing to have governing tariffs and contracts on file.

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[FN30]Finally, we find that the Commission's error in allowing Cascade to cancel its gas supply tariffs does not relieve Cascade from its responsibility to comply with the law. [FN31]

We assess penalties of $5,000 against the Company in Order 03 in Docket UG-061256 for its failure to file gas supply contracts with the Commission in violation of RCW 80.28.050 and WAC 480-80-143. [FN32]We also direct the Company to file with the Commission, within 30 days of the Order, new gas supply tariffs and any existing special contracts or we may initiate appropriate action against the Company, including additional penalties. [FN33]We do not void existing contracts, as doing so would be harmful to Cascade's customers who should not suffer adverse consequences caused by Cascade's actions. [FN34]

Although the Commission's action does not relieve Cascade of its responsibility to comply with state law, we find it inequitable to deny appropriate ratemaking treatment to services the Commission allowed Cascade to pursue without a tariff on file. Cascade's gas supply sales cannot be deemed to be completely unauthorized activity. Thus, we accept the parties' treatment in the Settlement of gas management services revenues and costs, including the stipulation in paragraph 12(b)(i) to reduce revenue requirement by $200,000 for revenues gained in gas management services and retail sales. We find it appropriate to allow core customers to benefit from Cascade's actions. We also accept the proposal for prospective treatment of revenues in paragraph 12(b)(ii), conditioned on the Company complying with statutory requirements within 30 days of the effective date of this Order and Order 03 in Docket UG-061256.

The provisions in paragraph 12 of the Settlement Agreement addressing restating and proforma adjustments, weather normalization and the treatment of competitive gas management services revenues meet our standards for accepting settlements. The provisions are neither contrary to law nor the public interest. The provisions reasonably resolve all contested revenue requirement issues in the rate case and are supported by the record, specifically the prefiled testimony and exhibits of Staff and Company witnesses Parvinen, Stoltz and Barnard. [FN35]

2. Miscellaneous Service Charges

[8, 9] In its initial filing, Cascade proposed numerous changes to existing service charges and proposed several new charges. [FN36]Staff, Public Counsel, NWEC and The Energy Project objected to Cascade's proposal, but differed in their proposed alternatives. [FN37]Cascade modified its proposed changes to service charges in responsive testimony. [FN38]

**7 In paragraph 13 of the Settlement, the Company, Staff, Public Counsel, NWEC and The Energy Project reach agreement on the miscellaneous service charges, as follows:

Disconnect Fee	$10.00
Reconnect Fee (during work hours)	$24.00
After Hours Reconnect Fee	$60.00 (except in case of medical emergency)
Pilot Light Service	$20.00
Late Fee	1% per month, applied to all unpaid balances 30 days past due
Minimum Late Fee	None
Meter Tampering Fee	Actual costs
NSF Check Return Charge	$18.00

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New Premises Charge	$45.00
Account Activation Fee	No charge
Short Notice Locate Fee	No charge

***202** The parties agree that these charges will produce revenues of $1,442,480. [FN39]

We accept the parties' stipulation to miscellaneous fees and charges and the resulting projected revenues. The stipulation reflects a consensus of the parties, based on evidence presented by the Company concerning the cost of service, and by other parties on the adverse effects on customers of increasing the fees and charges. [FN40]Furthermore, the stipulated fees will lessen the harmful impact on low-income customers. [FN41]For these reasons, we find the compromise to be in the public interest.

3. Low Income Assistance

[10, 11] In its initial filing, Cascade proposed to provide $800,000 to community action agencies in its service territory for bill assistance to low-income customers. [FN42]While Public Counsel and The Energy Project supported the Company's proposal, Staff rejected the proposal claiming the Company had not shown how the monies would be spent. [FN43]In rebuttal testimony, Cascade concurred with The Energy Project's proposals for how to implement a low-income assistance program. [FN44]

In paragraph 14(a) of the Settlement, Staff, the Company, The Energy Project, Public Counsel and NWEC agree that the Company's proposal for $800,000 in annual funding for low-income assistance should be included in revenue requirement. The Settlement provides that Cascade will apply for Public Utility tax credits for the low-income program and that any and all credits will be added to the base fund for the program. The Settlement describes how Cascade will implement a low-income assistance program using the network created by the Washington Department of Community, Trade and Economic Development. In addition, in paragraph 14(b), the Company agrees to work together with The Energy Project, Staff and other parties to collect data related to low-income customers. These parties will also consider whether the Company should implement an arrearage program to address delinquent customers and collection efforts.

The provisions in paragraph 14 reasonably resolve the contested issues concerning whether to include monies for a low-income assistance program in the revenue requirement, and are well supported by record evidence. The stipulated provisions are in the public interest, resulting in increased funds available to low-income customers for bill assistance. [FN45]

4. Rate Spread

****8 [12]** Cascade proposed to spread any revenue increase across all rate schedules based on the results of its cost-of-service study, rather than as an equal percentage of margin. [FN46]Staff, Public Counsel and NWIGU opposed the Company's cost-of-service study asserting it did not follow Commission-approved principles for such studies. [FN47]Staff, Public Counsel and ***203** NWIGU also opposed the Company's rate spread proposal, but agreed there was a need to move closer to cost-based rates. [FN48]Staff and NWIGU proposed modified studies following the Commission's guidelines, and Public Counsel recommended use of the NWIGU study. [FN49]In rebuttal, Cascade continued to propose cost-based rates and to oppose a rate spread based on an equal percent of margin, but agreed to partial movement to cost-based rates, supporting the use of NWIGU's cost-of-service study with modifications. [FN50]

In paragraph 16 of the Settlement Agreement, Staff, the Company and NWIGU agree to spread any revenue requirement increase across customer classes in accordance with the rate spread proposal in Attachment C to the Settlement. The parties agreed to reduce revenue requirement allocated to rate Schedules 663 and 664 - transportation schedules - by $1.751 million, and to allocate 90 percent of Miscellaneous Service Charge revenues to residential customers (Schedule 503) and 10 percent to commercial customers (Schedule 504).

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The provisions in paragraph 16 of the Settlement reasonably resolve the contested issues concerning rate spread and are supported by evidence in the record, *e.g.*, testimony and exhibits filed by the Company, Staff, Public Counsel, and NWIGU. We also find the stipulated provisions are consistent with the law and the public interest.

5. Rate Design

[13-16] In its initial filing, Cascade proposed to double the basic charges for all rate schedules, and to redesign transportation Schedules 663 and 664 based on the results of its cost-of-service study. [FN51]Staff supported the changes to basic service charges, while Public Counsel and The Energy Project opposed the proposal. [FN52]NWIGU opposed the Company's proposal, and recommended a different proposal for redesigning the transportation schedules. [FN53]In rebuttal, Cascade announced it had reached a compromise with NWIGU to consolidate Schedules 663 and 664, modify treatment of lost and unaccounted for gas, and adopt the Northwest Pipeline's rules for transportation service. [FN54]

Paragraph 17 of the Settlement includes three separate agreements concerning rate design. First, Staff, the Company and NWIGU agree to consolidate transportation Schedules 663 and 664 into one schedule, modify tariff provisions for options for electing firm service and lost and unaccounted for gas, and adopt the Northwest Pipeline's rules for transportation service. Second, Staff, the Company, Public Counsel, NWEC and The Energy Project agree to modify monthly basic service charges for certain schedules, without changing the residential basic service charge: [FN55]

5p

Schedule 503 (Residential)	No change ($4.00)
Schedule 504 (Commercial)	Increase from $7.00 to $10.00
Schedule 505 (Industrial)	Increase from $12.00 to $24.00
Schedule 511 (Large Volume)	Increase from $22.00 to $44.00
Schedule 512 (Compressed)	Increase from $7.00 to $14.00
Schedule 570 (Interruptible)	Increase from $22.00 to $44.00
Schedule 577 (Ltd. Interruptible)	Increase from $22.00 to $44.00

5p

****9** Finally, the Company and Staff agree to flatten blocks for Schedules 504, 505 and 511.

As with the stipulated provisions concerning rate spread issues, we find the provisions addressing rate design reasonably resolve the contested issues, are well supported by the record evidence, and consistent with the law and public interest.

6. SRIAM

[17, 18] In its initial filing, Cascade proposed an infrastructure investment tracking mechanism, which it referred to as the Safety ***204** and Reliability Infrastructure Adjustment Mechanism, or SRIAM. Cascade sought to include annually in rates the cost of service associated with certain investments in its pipeline and other facilities, *i.e.*, safety or reliability investments and facility relocations, without a general rate case. [FN56]

Staff, Public Counsel and NWIGU recommended the Commission reject the SRIAM proposal arguing it is poorly designed, represents piecemeal or single-issue ratemaking, and that Cascade has not demonstrated the need for the mechanism. [FN57]Cascade modified the

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SRIAM proposal in its rebuttal testimony, but continued to assert a need for the tracker. [FN58]

In paragraph 18 of the Settlement, Cascade agrees to withdraw its proposal for an infrastructure investment tracking mechanism. However, if the Commission approves Puget Sound Energy's (PSE) proposal for a depreciation tracker in Docket UE-060266, Cascade reserves the right to seek a single-issue filing similar to the depreciation tracker.

We accept Cascade's agreement to withdraw its SRIAM proposal as reasonable. Given our recent rejection of PSE's proposal for a depreciation tracker in Order 08 entered in Docket UE-060266, Cascade's reservation of right to seek a similar mechanism is moot. As a condition of our approval, that provision of the Settlement Agreement is stricken.

D. Contested Settlement Provisions

1. Cost of Capital

[19-22] Prior to reaching agreement in this case, the Company and Staff presented competing proposals for Cascade's capital structure and return on equity. The resulting difference in overall rate of return accounted for approximately $4.0 million (34 percent) of the gap between the Company's original revenue request and the Staff's original recommendation. [FN59]

Cascade sought an overall rate of return of 9.37 percent based on a hypothetical capital structure of 50 percent equity and 50 percent debt and a return on equity of 11.15 percent. [FN60]The Company asserted that this rate of return was necessary for it to attract capital to finance approximately $58 million (Washington share) of new mains and services over the next five years.

The Staff recommended an overall rate of return of 8.43 percent based on the Company's actual capital structure at the end of calendar year 2005 and a return on equity of 9.75 percent. [FN61]Staff recommended adjusting the return on equity downward by 25 basis points to 9.5 percent, producing a rate of return of 8.33 percent if the Commission approved decoupling. [FN62]

**10 Prior to settlement, the principle issues separating the Company and Staff were whether to (1) base cost of capital on a hypothetical capital structure or on actual capitalization, (2) include short-term debt, (3) adjust return on equity to reflect greater than average business risk or the effects of decoupling and other mechanisms that reduce risk, and (4) adjust the results of return on equity methods for flotation costs.

Staff and the Company do not resolve in the Settlement their disputes over capital structure, debt costs or return on equity. [FN63]Instead, in paragraph 12(a) of the Settlement Agreement, the settling parties recommend a 'revenue requirement with respect to the return' of $7,480,632 which they represent falls at the mid-point of the $9.368 million associated with Cascade's requested rate of return of 9.37 percent and the $5.571 million associated with the Staff's recommended rate of return of 8.33 percent. [FN64]The Company and Staff assert that this negotiated result includes the effect of an unquantifiable reduction in risk associated with the Settlement's decoupling proposal. [FN65]

Public Counsel objects to the parties' stipulation, asserting that it is impossible to determine whether the stipulated revenue requirement produces rates that are fair, just and reasonable because the stipulation does not specify a capital structure, return on equity or overall rate of return. [FN66]Public Counsel asserts that it is not possible to tell whether the settlement cost of capital falls in the middle of the range advocated by Staff and the Company because the *205 capital structure and return on equity are not identified. Public Counsel contends that failure to lay out a rate of return is 'arguably fatal to the stated revenue requirement' for three reasons: [FN67]

1) It does not allow the Commission to undertake a 'comprehensive review of the company's rate base and operating expenses, determining a fair rate of return, and allocating rate changes among rate payers.' [FN68]

2) Without an authorized rate of return, the Commission cannot determine whether the Company is over-earning between rate cases using the Commission Basis Reports required by WAC 480-90-257.

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3) The settlement does not adequately address a risk adjustment to rate of return to reflect a reduction in risk associated with decoupling.

In its Reply Brief, Public Counsel asserts that the representations of the Staff and Company regarding cost of capital and consideration of reduction in risk attributable to decoupling are unverifiable and not grounded in the record. According to Public Counsel, the Commission cannot determine that the cost of capital is 'in the middle' simply by representation by the parties. Public Counsel argues that the settling parties' claim that a risk adjustment is incorporated in the Settlement is unsubstantiated in the record, unverifiable, and provides no basis for a Commission finding. Public Counsel asserts that that it cannot support or rebut representations regarding the settling parties' agreement because the Settlement is a 'black box.' According to Public Counsel, the Commission should either set-aside Staff and Company representations regarding cost of capital or 'reopen' the Settlement to ensure that it is reasonable. [FN69]

**11 We address each of these contentions in turn, having previously identified our standards for reviewing settlements. [FN70]First, their nature, settlements are the product of negotiation and therefore are often opaque as to some of the methods, details and calculations that produce a result on which the parties can agree. A settlement can take many forms. In some cases the Commission has determined that an agreed adjustment to revenue requirement is acceptable even if it does not identify a specific rate of return. [FN71]In other cases, the Commission has approved settlements that include a rate of return but no detail concerning capital structure or the cost for the equity and debt components of capitalization. [FN72]In still other examples, approved settlements have been explicit about all of the components of the cost of capital. [FN73]In all of these examples, it was the end result of the proposed settlement's terms and revenue requirement that mattered, not the specific detail about how the result was achieved. We conclude that the lack of detail concerning cost of capital in this proposed settlement does not preclude its being a fair and reasonable resolution of the case, or prevent us from performing our statutory function of setting fair, just, reasonable and sufficient rates.

Second, while an identified rate of return is not a necessary condition for accepting a settlement, the lack of an identified and authorized rate of return makes it more difficult for parties and the Commission to monitor a company's earnings. We strongly disagree with both Staff and the Company on this point. [FN74]Identifying an authorized rate of return is particularly important in circumstances, as we have here, where new regulatory mechanisms heighten concerns that a utility's earnings may exceed a reasonable rate of return. In any event, contrary to Public Counsel's arguments, we can fairly estimate a stipulated rate of return in this proceeding. Staff and the Company have made it clear in the Settlement, Narrative Statement, and in response to a Commission Bench Request, that the agreed-upon overall rate of return is 8.85 percent. [FN75]The 8.85 percent rate of return falls at the mid-point of the 9.37 percent rate of return originally requested by the Company and the Staff's recommended risk-adjusted 8.33 percent rate of return.

We find the evidence sufficient to support this provision of the settlement. We also find the stipulated rate of return provides a benchmark against which to measure any potential complaints regarding over-earning. [FN76] The stipulated **206** rate of return is also a useful metric for implementing the proposed three-year pilot decoupling program we accept in principle in this Order. As we discuss further below, we require that the Company's Conservation Plan include an 'earnings cap' using the stipulated rate of return.

Finally, the evidence supports a finding that the stipulated rate of return includes a risk adjustment for decoupling. Both Staff and Cascade note that the settlement provides for a 'revenue requirement related to return' that falls near the midpoint of what would have been produced by the rates of return advocated by Company and Staff. [FN77]These advocated rates of return each included an adjustment for risk reduction. [FN78] We concur with Cascade's assertion that the actual effect of decoupling on risk is difficult to identify and quantify. [FN79]While the exact adjustment is not clear,

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the evidence demonstrates that the stipulated rate of return includes a risk adjustment.

**12 We reject Public Counsel's request to 'set-aside' the Company and Staff's representations or to 'reopen' the Settlement to test its reasonableness. The record supports the parties' stipulation, and our finding that the rates resulting from the settlement are fair, just, reasonable and sufficient, consistent with state law. Accepting the stipulation is also in the public interest, in that it allows the Commission to establish an overall rate of return for use as a benchmark for over-earning generally, as well as for use in implementing and evaluating the proposed pilot decoupling mechanism.

2. Decoupling Mechanism

[23-27] Decoupling is a ratemaking and regulatory tool intended to break the link between a utility's recovery of fixed costs and a consumer's energy consumption by reducing the impact of energy consumption on a utility's recovery of its fixed costs. Conservation advocates view decoupling as an important tool to promote greater conservation efforts by the utility.

Under traditional ratemaking structures, utilities recover a large portion of their fixed costs through charges based on the volume of energy that consumers use. Consequently, a reduction in energy consumption may lower the probability that the utility can fully recover its fixed costs. Energy consumption may be lower for a variety of reasons. Consumers may lower their thermostats or take shorter showers. More energy efficient building codes and appliances, better and more efficient insulation, and warmer than normal weather can also reduce energy use. Conversely, an increase in energy consumption may lead to a utility over-recovering its fixed costs. These base incentives, some argue, create an environment in which utilities do not support conservation because it is inconsistent with their economic interests.

The Company, Staff and NWEC propose in paragraph 15 of the Settlement Agreement that the Company be allowed to implement a three-year pilot 'partial' decoupling mechanism. Cascade would defer for future recovery revenue lost to lower than expected energy sales due to conservation and other non-weather related reasons. Staff asserts that in conjunction with the stipulation's requirement for a conservation plan, the decoupling proposal would align Cascade's ratemaking with Commission policy supporting energy efficiency. [FN80]Public Counsel vigorously opposes this portion of the Settlement arguing, among other things, that at best the proposed decoupling mechanism would make the Company indifferent to conservation. [FN81]

The main features of the stipulated decoupling mechanism include: [FN82]

• Deferred margin [FN83] variances based on weather normalized consumption volumes. The stipulation uses the weather normalization methodology the Company proposed for use in this case.

• Application only to rate schedules 503 and 505, *i.e.*, residential and commercial customers. (Hence, its 'partial' application).

• No adjustment made for new customers.

**13 • If necessary due to the magnitude of the deferrals to be amortized, the Company would extend the amortization period of such *207 deferrals to two years or more to lessen the impact on customers.

• In connection with the decoupling mechanism, the stipulation requires Cascade to undertake specific conservation activities during 2007:

o Within 30 days of the Commission's final order in this proceeding, Cascade must convene a conservation advisory group ('Advisory Group') of interested parties to consider the conservation potential study being performed by Stellar Processes.

o Within 90 days of the initial meeting of the Advisory Group, Cascade must file a Conservation and Low-Income Weatherization Plan. The Conservation Plan is to contain targets and benchmarks based upon recommendations of the Advisory Group and possible penalties and incentives.

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o Within 30 days of Commission approval of the Conservation Plan, Cascade must issue requests for proposals to implement the Plan. Agreements with third-party contractors must include targets and benchmarks, with possible penalties and incentives, so that payment is based on delivery of energy efficiency savings.

o By December 31, 2007, Cascade must satisfy the Commission that the Company can meet the Plan's 2008 energy efficiency targets.

• The mechanism may only be extended as part of a general rate case, and only after a thorough evaluation of the mechanism performed by an independent consultant.

Promoting energy conservation is a goal that we strongly support, and provides a highly appealing rationale for decoupling on its face. Our states' laws and policies encourage us to look with favor upon proposals to stimulate increased energy conservation as well. [FN84]Our statutory responsibility to regulate in the public interest, however, requires us to look beyond the abstract and examine the evidence to determine whether the facts support this rationale for Cascade. [FN85]

Like many proposed departures from traditional ratemaking structures, decoupling also has both potential advantages and disadvantages. A key disadvantage, as Public Counsel points out, is the potential shifting of risk to ratepayers. [FN86]Under the stipulated proposal, the risks of changes to weather-normalized consumption would shift to customers. Indeed all customers, regardless of their individual efforts to lower use, will experience a surcharge in rates should consumption by class fall below the expected level. This points us to a second potentially serious problem - the distortion of price signals and consequent dampening of customer conservation initiatives.

Balancing fixed-cost recovery on an annual basis via a surcharge or credit mechanism diminishes the value of rates as a means to send appropriate price signals to customers. Based on changing energy market conditions, price signals undoubtedly affect customer choices to conserve or not. This price signal may be weakened if customers conserve and then are faced with paying a surcharge that reduces their financial benefit. In those circumstances, decoupling actually may prove counterproductive to its laudable purpose. Just as we must be concerned that in some instances the absence of decoupling or something similar may prove a disincentive to a company promoting conservation, the implementation of decoupling, and associated surcharges, may prove a disincentive to customers who might be inclined to conserve if it is to their financial advantage.

14 A third potential problem, vigorously argued by Public Counsel, is the risk over time of distorting the 'matching principle ' through single issue ratemaking [FN87] Under this principle, revenues and costs are balanced at a common point in time, *i.e.*, a rate case, to determine fair, just, reasonable and sufficient rates. If a company is largely assured recovery of fixed costs and most variable costs are routinely passed through to customers (*e.g.*, via purchased gas adjustment mechanisms and the like), then the company has fewer reasons to file a general rate case. In this context, any cost savings achieved ***208 by the company are not shared with customers. The result risks over-earning by the company and over-paying by the customers.

Considering these concerns, we must examine carefully the stipulated proposal to determine whether the record is sufficient to prove the potential advantages from decoupling outweigh its potential disadvantages in this case.

A fundamental test in this regard is the likelihood of increased conservation as a result of implementing a decoupling program. Cascade's record of encouraging and achieving significant amounts of conservation is a concern. Currently, the Company provides incentives for high-efficiency furnaces and water heaters to residential customers, high-efficiency equipment and insulation for commercial and industrial customers, and weatherization for low-income customers. Staff observes that the commercial and low-income programs went into effect in the fall of 2005. Apparently, the Company began implementing these programs only after evaluating their feasibility in its integrated resource plan. [FN88]

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Public Counsel asserts that decoupling does not guarantee utility-sponsored conservation, but at best, makes the Company indifferent to conservation. [FN89]NWEC presents the countervailing view that decoupling is an important tool in shaping corporate culture over the longer term so that utilities will aggressively implement, or at least be open to implementing incremental conservation measures. [FN90]At this point we are uncertain what effect decoupling would have on Cascade's corporate culture. While the Company's history suggests some corporate ambivalence towards conservation, Cascade has recently taken steps to initiate some conservation programs.

We note that the stipulation requires Cascade to develop a Conservation Plan that includes targets and benchmarks, and possible penalties and incentives. [FN91]Cascade has contracted with a consultant to prepare an assessment of the energy efficiency program potential in its service area in Washington. This report should provide a foundation for developing the Conservation Plan and savings targets. [FN92]The stipulation also commits Cascade to issuing requests for proposals, or RFPs, for third-party implementation within 30 days of Commission approval of the Plan. [FN93]The inclusion of the Conservation Plan, with its mechanisms and commitments to ensure the Company delivers on the promise of conservation through real incentives and penalties, leads us to conclude that the proposed decoupling mechanism may increase company-sponsored conservation.

**15 Another significant concern regarding decoupling mechanisms is the potential for so-called windfall profits. Public Counsel argues that Cascade loses a very small margin from its conservation programs - less than $10,000 a year - and that decoupling could produce 'windfall' revenues for the Company because all changes in gas usage (except weather variations) would be swept together for rate recovery. [FN94]Staff and NWEC acknowledge that windfall recovery could occur after implementing a decoupling proposal. [FN95]NWEC proposes several mechanisms to prevent or address such a windfall. [FN96]Even Cascade's President David Stevens acknowledges that if decoupling is approved, Cascade will likely receive additional revenue without a rate case. [FN97]Both Cascade and NWEC contend, however, that Public Counsel's reference to the Company's over-earning in Oregon is not relevant to decoupling since any over-earning occurred before decoupling was implemented for Cascade in Oregon. [FN98]

The Commission favors the resolution of contested issues through settlement 'when doing so is lawful and consistent with the public interest.' [FN99] While we find merit in the Company's commitments for increased conservation should we allow Cascade to implement the stipulated three-year pilot, partial decoupling mechanism, we are concerned about the shift in risk that might allow the utility to receive a potential unwarranted financial windfall. This concern is not adequately addressed by the stipulation. The testimony in this case leads us to conclude that the stipulated decoupling proposal should include a mechanism to prevent such potential over-earning. [FN100]

Therefore, we condition our full acceptance*209 of the proposed decoupling mechanism pending review and approval of the Company's Conservation Plan. We condition our approval of the Plan under paragraph 15(e)(ii) of the Settlement on inclusion of an earnings cap based on a stipulated overall rate of return of 8.85 percent and an appropriate and verifiable mechanism to assess how the earnings would be determined and compared to the authorized rate of return. We believe including these conditions on the Settlement will provide an effective safeguard against potential over-earning, and allow us to assess its usefulness during the pilot program.

To ensure that the pilot mechanism increases the potential for increased conservation, we also condition our approval of the Conservation Plan on it definitively including penalties for the Company's failure to meet conservation targets and benchmarks, including limiting Cascade's collection of surcharges under the proposal. The Settlement provides only that '[t]he Plan shall include possible penalties and incentives.' [FN101] This is not sufficiently clear to ensure that the Company has strong incentives to achieve the targets set forth in the Conservation Plan.

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We note that paragraph 15(d) of the Settlement Agreement implies that the Company may choose whether to amortize deferrals under the pilot mechanism depending on the size of the deferrals. We remind the parties that any amount the Company seeks to defer or amortize is subject to our approval. The Commission will determine whether amortization is appropriate in considering the Company's annual deferral tracking mechanism.

**16 Finally, we require that the evaluation of the mechanism proposed in paragraph 15(c) of the Settlement be performed and submitted to the Commission regardless of whether Cascade chooses to file a general rate case after the three-year pilot period expires. The Settlement implies that the evaluation will be performed only if Cascade opts to file a general rate case to continue the program. We find that an evaluation of this pilot program is important to determining the value of decoupling mechanisms for regulated utilities in Washington State.

The settling parties should consider our conditional approval of a partial three-year pilot decoupling mechanism as an opportunity to demonstrate that decoupling mechanisms promote incremental increases in utility-sponsored conservation. We will closely scrutinize the evaluation of the mechanism. Any extension will depend upon demonstrable proof that the mechanism enhanced Cascade's conservation efforts and achievements without unduly harming the interests of customers.

E. Conditional Acceptance of the Settlement

[28, 29] Consistent with prior decisions, we note that settlements 'are by nature compromises of more extreme positions that are supported by evidence and advocacy.' [FN102] Finding that '[r]atemaking is not an exact science,' we accept the parties' multi-party, multi-issue Settlement Agreement, subject to our conditions, on the basis that 'the overall result in terms of revenue requirement is reasonable and well supported by the evidence.' [FN103]

We include the following conditions on our acceptance of the Settlement Agreement:

1) The Company must comply within 30 days of the effective date of this Order with statutory requirements for filing tariffs and contracts governing its gas supply operations, or the proposal for prospective treatment of revenues in paragraph 12(b)(ii) of the Settlement Agreement is rejected;

2) The Company must strike the second sentence of p aragraph 18 governing Cascade's reservation of right to make a single-issue filing similar to PSE's request for a depreciation tracking mechanism;

3) The parties agree to stipulate to an overall rate of return for Cascade of 8.85 percent for purposes of calculating the Company's cost of capital under paragraph 12(a) of the Settlement Agreement;

4) The parties to the Advisory Group must agree to include in the Conservation Plan contemplated in paragraph 15(e) of the Settlement an earnings cap based on the stipulated*210 overall rate of return, a verifiable mechanism to assess whether earnings are within the rate of return, and penalties for the Company's failure to meet targets and benchmarks; and

5) The Company must conduct an evaluation of the pilot decoupling proposal regardless of whether it seeks to continue the program pursuant to paragraph 15(c) of the Settlement after the three-year pilot period expires.

These conditions do not alter the ability of Cascade to recover necessary revenues, or the rates or charges resulting from the Settlement Agreement. The conditions impose safeguards, primarily upon the implementation and evaluation of the three-year pilot decoupling mechanism that we accept in principle in this Order. Should the parties accept the conditions, we determine that Cascade should be authorized and required to file rates in compliance with our decisions. When implemented via the compliance filing we require the Company to make, we find that the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential.

**17 *FINDINGS OF FACT*

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Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary findings of fact, incorporating by reference pertinent portions of the preceding detailed findings:

(1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas companies.

(2) Cascade Natural Gas Corporation is a 'public service company' and a 'gas company,' as those terms are defined in RCW 80.04.010, and as those terms otherwise are used in RCW Title 80. Cascade is engaged in Washington State in the business of supplying utility services and natural gas to the public for compensation.

(3) Cascade filed revisions to its tariffs on February 14, 2006, requesting an increase in annual revenues from Washington operations of $11.7 million, or about 4.5 percent. The Commission suspended the proposed tariff revisions on March 15, 2006.

(4) After the parties filed testimony addressing the contested issues in this proceeding, the parties entered into a multi-party, multi-issue Settlement Agreement addressing all contested issues, and providing for an increase in revenue requirement of $7,061,536, which would result in an overall 2.7 percent increase relative to current rates. The Settlement Agreement is attached to this Order as Appendix A.

(5) Public Counsel contests the provisions in the Settlement Agreement concerning the resolution of the Company's cost-of capital and a proposal for a 'partial' pilot decoupling program.

(6) The Company and Staff agree that an overall rate of return for the Company of 8.85 percent can be fairly estimated from the terms of the Settlement Agreement and the record evidence.

(7) The stipulated overall rate of return falls near the midpoint of what would have been produced by the rates of return advocated by Staff and the Company.

(8) The rates of return advocated by Staff and the Company each included an adjustment for risk-reduction assuming Commission approval of a decoupling mechanism.

(9) The stipulated decoupling program, with the inclusion of the Conservation Plan and its mechanisms and commitments to ensure the Company delivers on the promise of conservation through real incentives and penalties, has merit and may increase Company conservation.

(10) The stipulated decoupling mechanism does not adequately address the possibility***211** that the resulting shift in risk might allow the utility to receive a potential unwarranted financial windfall.

(11) Conditioning approval of the Company's Conservation Plan on including an earnings cap based on a stipulated overall rate of return of 8.85 percent and an appropriate and verifiable assessment mechanism will provide an effective safeguard against potential overearning, and allow the Commission to assess its usefulness during the pilot program.

****18** (12) An evaluation of the pilot, partial decoupling program, regardless of whether the Company seeks to continue the program after the three-year pilot period expires is important to determining the value of decoupling mechanisms for regulated utilities in Washington State.

CONCLUSIONS OF LAW

Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law incorporating by reference pertinent portions of the preceding detailed conclusions:

(1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and

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parties to, this proceeding.*RCW Title 80.*

(2) The rates proposed in the tariff revisions filed by Cascade and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.*RCW 80.28.010.*

(3) Cascade's existing rates for natural gas service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.*RCW 80.28.010; RCW 80.28.020.*

(4) Cascade requires relief with respect to the rates it charges for natural gas service provided in Washington State.*RCW 80.01.040; RCW 80.28.060.*

(5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under Cascade's tariffs that govern its rates, terms, and conditions of service for providing natural gas to customers in Washington State.*RCW 80.28.020.*

(6) The Commission may approve settlements 'when doing so is lawful, when the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission.' *WAC 480-07-750(1).*

(7) The uncontested provisions of the Settlement Agreement reasonably resolve contested issues in this case, are supported by evidence in the record and are consistent with the law and the public interest.

(8) The Settlement Agreement, as modified by the conditions we set in this Order, is supported by the record, and is consistent with the law and public interest.

(9) It would be inequitable to deny appropriate ratemaking treatment to gas supply services the Commission allowed Cascade to pursue without a tariff on file.

(10) Cascade should be authorized and required to make a compliance filing to recover its revenue deficiency of $7,061,536 for natural gas service, as discussed in this Order.*WAC 480-07-880(1).*

(11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.*RCW 80.28.010; RCW 80.28.020.*

(12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.*RCW 80.28.020.*

(13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.*WAC 480-07-170; WAC 480-07-880.*

****19** (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.*RCW Title 80.*

**212 ORDER*

THE COMMISSION ORDERS:

(1) The proposed tariff revisions Cascade Natural Gas Corporation filed on February 14, 2006, which were suspended by prior Commission order, are rejected.

(2) The multi-party Settlement Agreement filed in this proceeding on October 11, 2006, which is attached to this Order as Appendix A and incorporated by reference as if set forth in full in the body of this Order, is accepted subject to the conditions set forth in paragraph 87 of this Order.

(3) If the parties accept the conditions on the Settlement Agreement set forth in this Order, Cascade Natural Gas Corporation is authorized and required to file tariff sheets following the effective date of this Order that are necessary and sufficient to effectuate its terms.

(4) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

(5) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Olympia, Washington, and effective January 12, 2007.

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APPENDIX A

Settlement Agreement

GLOSSARY

TERM	DESCRIPTION
Balancing	A service gas companies provide to ensure that the receipts and deliveries of gas into or withdrawals from a company's system equal, so that the company has sufficient daily gas supply to meet the daily needs of its core and non-core customers.
CMS	Cost Management Services, Inc. A competitive gas marketer, supplying and selling natural gas to industrial and commercial customers, including Cascade customers who take transportation-only service from Cascade under Schedules 663 and 664.
Core Customers	Usually residential and commercial customers who purchase gas service from a local distribution company as a bundled service, receiving transportation along the LDC's distribution system and gas supply, as well as other services, in one package under tariff.
Decoupling	A ratemaking and regulatory tool intended to break the link between a utility's recovery of fixed costs and a consumer's energy consumption by reducing the impact of energy consumption on a utility's recovery of fixed costs.
FERC	The Federal Energy Regulatory Commission.
Firm Service	Natural gas capacity, intended to be available to a customer at

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	all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions. Also, a non-interruptible gas contract required for all customers with essential human needs (e.g. hospitals, health-care facilities and residences).
TERM	DESCRIPTION
Gas Supply	A service gas companies and private gas marketers provide in selling natural gas as a commodity on a competitive basis, usually under contract.
LDC	Local distribution company. The company that owns and operates the piping that delivers natural gas to the consumer.
Margin Revenue	The revenue necessary for a utility to recover its total cost of service net of purchased gas expenses and other expenses treated as 'flow-through' items in rates (e.g., revenue taxes, conservation program riders). A utility's per customer margin revenue is its total cost of service, as determined in the most recent general rate case, divided by the number of customers.
Non-Core Customers	Customers who purchase transportation and gas supply as separate services, also known as unbundled services. Non-core customers are mostly large industrial customers who can purchase gas on the

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	market, competitively, from an LDC or a gas marketer.
NSF	Non-sufficient funds. A non-sufficient funds check is a check returned by a bank to its customers for insufficient funds in the customer's account to cover the check.
NWEC	The Northwest Energy Coalition. An alliance of environmental, civic, and human service organizations, utilities, and businesses in Oregon, Washington, Idaho, Montana, Alaska and British Columbia that promotes development of renewable energy and energy conservation, consumer protection, low-income energy assistance, and fish and wildlife restoration on the Columbia and Snake rivers.
NWIGU	The Northwest Industrial Gas Users. An organization whose members are large industrial natural gas customers taking service from various utilities, including Cascade.
Pipeline Capacity	The maximum amount of natural gas which can be delivered through a pipeline within a specific period of time.
SRIAM	Safety and Reliability Infrastructure Adjustment Mechanism. The name coined by Cascade to identify its proposal in this proceeding to track investments in non-revenue producing pipeline infrastructure for the purpose of annually adjusting rates.
Transportation	In this case, movement of natural gas from a city gate point of receipt to natural gas consumers through distribution mains. Trans-

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portation
can also mean between the movement of gas from the well or gas
field to a central point for delivery to a pipeline or processing plant
within the same state.

Transportation-only Service

A service LDCs provide to allow customers the option of purchasing
the transportation of gas over the company's distribution facilities
separately, or unbundled, from the purchase of gas supply and other
services, such as balancing, pipeline capacity and other gas management services.

**20 *214 *SETTLEMENT AGREEMENT*

PARTIES

1. This settlement agreement is entered into by Cascade Natural Gas Corporation ('Cascade' or 'the Company'), Staff of the Washington Utilities and Transportation Commission ('Staff'), Public Counsel Section of the Washington Attorney General's Office ('Public Counsel'), Northwest Industrial Gas Users ('NWIGU'), NW Energy Coalition ('NWEC'). The Energy Project, and Cost Management Services, Inc. ('CMS') regarding Cascade's pending general rate filing in the above docket.

RECITALS

2. On February 14, 2006. Cascade filed tariff sheets seeking a general rate increase of $11.7 million, or 4.47%. The filing was based on normalized results of operations for Washington for the test period ending September 30, 2005. The filing was suspended by the Commission at its March 15, 2006 public meeting.

3. At the prehearing conference on April 11, 2006. NWIGU. The Energy Project, NWEC, International Chemical Workers Union, CMS, and Mint Farm Energy Center LLC were granted intervention in the proceed- ing.

4. Following discovery by Staff and the other parties on the Company's direct testimony, a settlement conference was convened at the Commission's offices on July 25, Follow-up discussions were held the following week. On August 15, Staff, Public Counsel, NWIGU. The Energy Project, NWEC and CMS filed opposing testimony. Staff recommended limiting the rate increase to $1.6 million. No other party submitted testimony regarding an overall revenue requirement recommendation; Public Counsel, NWEC, and The Energy Project submitted testimony regarding revenues to be recovered from Miscellaneous Service Charges.

5. The Company submitted rebuttal testimony on September 12, 2006: other parties also submitted cross-rebuttal testimony. Hearings are scheduled for October 9-13. The suspension period ends on January 16, 2007.

6. Following discovery on the rebuttal testimony, the Company, Staff, Public Counsel and other parties convened settlement discussions for purposes of resolving or narrowing the contested issues in this proceeding.

7. The Company and Staff reached agreement on various revenue requirement issues in this proceeding, and

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filed a Stipulation on Revenue Requirement Issues ('Revenue Stipulation') with the Commission on October 4, 2006.

8. The Company, Staff and NWIGU reached agreement on various rate spread and rate design issues, and filed a Stipulation on Rate Spread, Rate Design Issues ('Rates Stipulation') with the Commission on October 5, 2006.

9. The Company, Staff, NWIGU, Public Counsel, NWEC, The Energy Project, and CMS ('the Parties') have reached agreement on certain of the contested issues in this proceeding and wish to present these agreements for the Commission's consideration. The Parties therefore adopt the following agreement, which is entered into by the Parties voluntarily to resolve matters in dispute among them in the interests of expediting the orderly disposition of this proceeding. This is a multi-issue settlement resolving a number of contested issues in the case. It should be noted that Parties agreeing to resolve one contested issue may or may not have agreed to resolve other issues. Accordingly, this multi-issue, multi-party agreement, while an integrated document, actually contains a number of stipulated recommendations on individual issues. For ease of reference, however, the Parties refer to the document as the 'Settlement Agreement,' understanding that it is not a global settlement, (*i.e.*, a settlement in which all parties agree on the resolution of all issues presented for settlement). The Settlement Agreement is being filed with the Commission as a 'Multiparty Settlement' pursuant to WAC 480-07-730(3).

****21** *AGREEMENT*

10. *Revenue Stipulation.* Staff and the Company agree that the Revenue Stipulation filed October 4, 2006 shall be vacated. The revenue***215** requirement issues agreed upon by Staff and the Company in the Revenue Stipulation are incorporated into this Settlement Agreement.

11. *Rates Stipulation.* Staff, the Company, and NWIGU agree that the Rates Stipulation filed October 5, 2006 shall be vacated. The rate spread and rate design issues agreed upon by Staff, the Company, and NWIGU in the Rates Stipulation are incorporated into this Settlement Agreement.

12. *Revenue Requirement Issues.* Staff and the Company agree that Cascade will reduce its revenue requirement request to reflect the adjustments listed below, which result in a recommended revenue requirement increase of $7,061.536, or approximately 2.69%. Included as Attachment A is a summary sheet showing the calculations supporting the recommended revenue requirement increase. Except as expressly set forth with respect to individual issues set forth below, no Party other than Staff and the Company takes a position with respect to the revenue requirement issues set forth in this paragraph 12. No Party will take a position in this proceeding with respect to revenue requirement issues that is contrary to or inconsistent with the adjustments set forth in this paragraph 12.

a. *Cost of Capital.* A number of issues were in dispute between Staff and the Company with respect to cost of capital, including return on equity, common equity ratio, and whether short-term debt should be included in the capital structure. Although Staff and the Company were unable to reach agreement on each of the components of the cost of capital, they agree that the revenue requirement for the overall return is $7,480.632, as shown on Attachment A. Public Counsel reserves the right to take a position on cost of capital that may be contrary or inconsistent with this paragraph 12(a).

b. *Gas Management Services.*

(i) *Test Period Treatment.* Staff and the Company agree to accept the Company's adjustment for 'Removal of Non-Core Competitive Services Revenues and Gas Costs.' as set forth in Exhibit Nos. ___ (JTS-1T), pages 6-7, and ___ (JTS-4): provided, however, that such adjustment shall be revised to reflect the inclusion of $200.000 in revenues from Gas Management Services for purposes of determining the revenue requirement in this proceeding.

(ii) *Prospective Treatment.* The Parties agree that effective as of the date of the Commission's final order in this proceeding and continuing until the effective date

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of the final order in the Company's next general rate case, the Company will defer fifty percent (50%) of the Net Margins realized each month by the Company for Gas Management Services. Amounts deferred in accordance with this paragraph 12(b)(ii) shall be returned on an equal percentage margin basis to all customers, except Special Contract customers, each year as part of the Company's Temporary Deferral Tracking Adjustment filing, commencing as of the filing in Fall 2007. For purposes of this section, 'Net Margin' means gross revenue from Gas Management Services, less (1) the cost of gas and (2) revenue-sensitive costs.

**22 (iii) *Tariff Revisions*. In connection with the modifications to rate design, the Company will he filing revisions to Rate Schedules 663 and 664 to implement the recommended rate design changes. The Company and CMS agree that those tariff revisions shall include elimination of the following language from the 'Other Services' section of the current Schedules 663 and 664:

Gas Supplies purchased through the Company will be in accordance with the FERC regulations (18 CFR Part 284.402 Blanket Marketing Certificates).

(iv) *Stipulated Facts in Complaint Proceeding*. CMS has commenced a separate complaint proceeding against Cascade *216 (Docket No. UG-061256) with respect to gas management services. The Company and CMS agree that the stipulated facts included as Attachment B to this Settlement Agreement shall be included as stipulated facts for purposes of the record in Docket No. UG-061256.The Company shall have the right to include additional stipulated facts in the development of the record in Docket No. UG-061256.

c. *Weather Normalization*. For purposes of calculating a weather normalization adjustment. Staff and the Company agree to use a margin adjustment of $730,779, as set forth in Exhibit No. ___ (JTS-6). Schedule 1, Line 5. Column (d). This is a stipulated amount for purposes only of calculating the revenue requirement in this proceeding; no Party expresses any view about the underlying methodology used to calculate either the 'normal' heating degree days (HDDs) or the weather-sensitive coefficients.

d. *Pro Forma Adjustments*. Staff and the Company agree on the following treatment of various adjustments in calculating the Company's revenue requirement in this proceeding:

(i) Elimination of the Company's proposed pro forma adjustment for Gas Management & Risk Management Software (Parvinen, Exhibit No. ___ (MPP-1T), pages 17-18).

(ii) Acceptance of the Company's proposed pro forma adjustment for Integrated Resource Planning Costs (Barnard. Exhibit Nos. ___ (KJB-1T), page 17 and ___ (KJB-17).

(iii) Elimination of the Company's proposed pro forma adjustment for CIS Hardware Upgrade (Parvinen. Exhibit No. ___ (MPP-1T), page 19).

(iv) Acceptance of Staff's proposed adjustment to reflect escalation clauses in the Company's Special Contracts with various customers (Parvinen, Exhibit No. ___ (MPP-1T), page 21).

(v) Acceptance of Staff's proposed adjustment to restate gas costs for Lost and Unaccounted For Gas (Parvinen, Exhibit No. ___ (MPP-1T), page 12).

(vi) Acceptance of Staff's proposed adjustment to restate Wages and Related Costs (Parvinen, Exhibit No. ___ (MPP-1T). page 12).

(vii) Acceptance of Staff's proposed adjustment to restate books to reflect actual Uncollectible Expenses (Parvinen. Exhibit No. ___ (MPP-1T). page 13).

(viii) Acceptance of Staff's proposed adjustment for Pro Forma Wages and Related Costs (Parvinen, Exhibit No. ___ (MPP-1T). pages 13-14).

(ix) Acceptance of Staff's calculation of Working Capital (Parvinen, Exhibit No. ___ (MPP-1T). pages 6-8: Exhibit No. ___ (MPP-4)).

**23 (x) Use of a 34% federal income tax rate, as proposed by Staff (Parvinen, Exhibit No. ___ (MPP-1T), pages 15-16). including the impact of the federal in-

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come tax rate on the uncontested adjustments shown on Exhibit No. ___ (MPP-1T). page 9, lines 3-14 and on the conversion factor (Exhibit No. ___ (MPP-3). page 25).

(xi) Acceptance of Staff's proposed adjustment for Conservation Promotional Advertising (Parvinen. Exhibit No. ___ (MPP-1T). page 20).

(xii) Acceptance of the Company's proposed rate case expense (Stoltz. Exhibit No. ___ (JTS-11)).

e. *Evidentiary Support.* As evidentiary support for these stipulated revenue requirement issues, the Parties cite certain testimony and exhibits of Staff witness Michael P. Parvinen (Exhibit Nos. ___ (MPP-1T). ___ (MPP-2), ___ (MPP-3). ___ (MPP-4), and ___ (MPP-7)), certain testimony and exhibits of Company witness Katherine J. Barnard (Exhibit Nos. ___ (KJB-1T) and ___ (KJB-2)). and certain testimony and exhibits of Company witness Jon T. Stoltz (Exhibit Nos. ___ (JTS-1T). ___ (JTS-10T) and ___ (JTS-11)).

***217** 13. *Miscellaneous Service Charges.*

a. *Level of Charges.* Staff, the Company, Public Counsel. NWEC, and The Energy Project agree that the Miscellaneous Service Charges shall be as follows:

Disconnect Fee	$10.00
Reconnect Fee (during work hours)	$24.00
After Hours Reconnect Fee	$60.00 (except in case of medical emergency)
Pilot Light Service	$20.00
Late Fee	1% per month, applied to all unpaid balances 30 days past due
Minimum Late Fee	None
Meter Tampering Fee	Actual costs
NSF Check Return Charge	$18.00
New Premises Charge	$45.00
Account Activation Fee	No charge
Short Notice Locate Fee	No charge

The Parties agree that for purposes of determining the Company's revenue requirement in this proceeding, these Miscellaneous Service Charges shall be deemed to produce revenues of $1,442,480, or an increase of $1,129,498 over test period revenues of $312,982.

b. *Evidentiary Support.* As evidentiary support for these stipulated Miscellaneous Service Charges, the Parties cite certain testimony and exhibits of Staff witness Michael Parvinen (Exhibit Nos. ___ (MPP-1T). pages 22-25, and ___ (MPP-5)) and certain testimony and exhibits of Company witness Jon T. Stoltz (Exhibit Nos. ___ (JTS-1T). pages 15-18, ___ (JTS-9), Schedule 2, and (JTS-10T), pages 32-35).

14. *Low-Income Assistance.*

a. *Funding.* Staff, the Company, The Energy Project, Public Counsel, and NWEC agree that the Company's proposal for $800,000 in annual funding for low-income assistance, as described in Exhibit No. ___ (KJB-21T). pages 6-7. shall be included in the revenue requirement in this proceeding. Each year the Company shall apply in a timely fashion for Public Utility tax credits for its

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low-income assistance program: any and all credits will be added to the base fund for the program. As described in the testimony of The Energy Project witness Eberdt. (Exhibit No. ___ (CME-1T), pages 6-7). the existing network used by the Washington Department of Community, Trade and Economic Development for the Low Income Home Energy Assistance Program (LIHEAP) will be used. Funds will be allocated proportionally according to LIHEAP gas funds distribution in the Company's service territory.

**24 b. *Collection of Data.* The Company agrees that within ninety (90) days after the Commission's final order in this proceeding, it will initiate a collaborative effort with Staff, representatives of The Energy Project and other interested parties to track low-income issues by identifying and collecting data pertinent to low-income customers in the Company's Washington service territory. Such collaborative effort shall also consider whether the Company should implement an arrearage management project for low-income customers. The goals for the project would be reducing service terminations, reducing referral of delinquent customers to third party collection agencies, reducing collection litigation and reducing arrearages, reducing the Company's costs associated with these activities, and increasing voluntary customer payment of arrearages.

*218 15. *Decoupling Mechanism.* Staff, the Company and NWEC agree that the Company shall be authorized to implement a decoupling mechanism, under the terms and conditions set forth in this paragraph 15. Public Counsel does not join in this portion of the Settlement Agreement, and expressly reserves the right to oppose implementation of decoupling and to cross-examine witnesses on this issue. No Party other than Staff, the Company, NWEC and Public Counsel takes a position with respect to the implementation of decoupling. No Party other than Public Counsel will take a position with respect to implementation of decoupling that is contrary to or inconsistent with this paragraph 15.

a. *Scope of Mechanism.* The mechanism shall be a 'partial' decoupling mechanism which defers margin variances based on weather-normalized volumes (*i.e.*, the scope shall include only the non-weather related effects that cause changes in usage such as customer conservation and energy efficiency improvements), as described in the testimony of Staff witness Steward (Exhibit No. ___ (JRS-1T). page 6. The mechanism shall apply only to Rate Schedules 503 and 504. For purposes of calculating the base usage per customer and the resulting deferrals, no adjustment shall be made for new customers.

b. *Weather Normalization Methodology.* For purposes of calculating the impacts of weather on use per customer for implementation of the decoupling mechanism, the Parties agree to use the Company's weather normalization methodology as set forth in Exhibit Nos. ___ (JTS-1T), pages 9-12. and ___ (JTS-6). The Parties agree that this weather normalization methodology will remain in place throughout the Pilot Period. This is a stipulated weather normalization methodology for purposes only of calculating deferrals under the decoupling mechanism; no Party expresses any view about the underlying methodology used to calculate either the 'normal' heating degree days (HDDs) or the weather-sensitive coefficients.

c. *Pilot Program.* The decoupling mechanism shall be implemented on a 'pilot' basis, as described in the testimony of Staff witness Steward (Exhibit No. ___ (JRS-1T), pages 16-17. The mechanism shall expire, by its terms, three (3) years from the effective date of the tariff sheets implementing the mechanism. The mechanism may be extended if (i) such extension is authorized as part of a general rate case to be filed by the Company prior to the expiration of the mechanism, and (ii) such general rate filing includes the results of a thorough evaluation of the mechanism. Such evaluation shall be performed by an independent consultant retained by the Company after consultation with interested parties. The scope and timing of such evaluation shall be as defined by the Company and interested parties; whether or not the decoupling mechanism is recommended for extension, an evaluation must be completed and delivered to the Commission within twelve months of completion of the pilot. Any evaluation shall consider, among other things, the following:

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**25 • What customer classes should be included within the scope of the mechanism?

• How well does the mechanism remove Cascade's disincentive to promote energy efficiency?

• What would the bill impacts have been if weather-related impact on usage was included?

• Was there any discernible effect on service quality due to the existence of the mechanism?

The Company may seek recovery of the costs of such evaluation in future rate proceedings.

d. *Limitation on Deferrals.* Rather than imposing any specific cap on the level of annual surcharges under the mechanism, the Company shall consider the rate impact of the annual surcharge produced by the mechanism and, if necessary due to the magnitude of the deferrals to be amortized, shall extend the amortization period of such deferrals to *219 two years or more to lessen the impact on customers.

e. *Conservation Program and Performance.*

(i) The Company shall convene a conservation advisory group ('Advisory Group ') of all interested parties to meet no later than thirty (30) days after the Commission's final order in this proceeding. The Advisory Group shall consider, among other things, the conservation potential study being performed for the Company by Stellar Processes.

(ii) No later than ninety (90) days after the initial meeting of the Advisory Group, the Company shall file with the Commission a Conservation and Low Income Weatherization Plan with reasonably achievable specific programmatic and energy efficiency targets and related benchmarks for at least 2008 and 2009 based upon the study and the recommendations of the Advisory Group. The Plan shall include possible penalties and incentives, and shall be submitted to the Commission for approval.

(iii) Within thirty (30) days of Commission approval of the Plan, the Company shall issue requests for proposals, or RFPs, for third-party implementation of the Plan. Agreements with third-party contractors shall include specific programmatic and performance targets and benchmarks, with possible penalties and incentives, to ensure that payment is based on delivery of energy efficiency savings.

(iv) No later than December 31, 2007, the Company must demonstrate to the satisfaction of the Commission that it has the ability to meet the 2008 energy efficiency targets identified in the Plan. This demonstration may be made by showing that the Company has contracted with qualified third-party providers to be able to deliver effectively the energy efficiency programs included in its 2008 target. If the Company fails to meet this benchmark, it shall be assessed a penalty in 2008 as prescribed in the Plan.

(v) If the Company demonstrates its ability to meet the 2008 energy efficiency target by year-end 2007. it will continue to defer margin revenues pursuant to this decoupling mechanism. In the event the Company fails to meet its 2008 target, it shall be assessed a penalty in 2009 as prescribed in the Plan.

(vi) In the event the Company fails to meet its 2009 target, it shall be assessed a penalty in 2010 as prescribed in the Plan.

16. *Rate Spread.*

**26 a. Staff, the Company and NWIGU agree that any revenue requirement increase shall be allocated across customer classes in accordance with the rate spread proposal set forth in Attachment C to this Stipulation. No Party other than Staff, the Company, and NWIGU takes a position with respect to rate spread in this proceeding. No Party will take a position in this proceeding with respect to rate spread that is contrary to or inconsistent with this paragraph 16.

b. Attachment C reflects the following elements:

(i) The revenue requirement allocated to Rate Schedules 663 and 664 shall be reduced by $1.751 million from current levels. Exhibit No. ___ (DWS-1T) shows that a

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net margin decrease of up to three times that amount for Rate Schedules 663 and 664 could be justified.

(ii) Any increase in Miscellaneous Service Charge revenues, as determined by the Commission in its final order in this proceeding, shall be assigned 90% to Rate Schedule 503 and 10% to Rate Schedule 504.

(iii) Remaining revenue requirement changes shall be allocated to the remaining core rate schedules in accordance with the rate spread proposal included as Attachment C to this Stipulation.

c. *Evidentiary Support.* As evidentiary support for this stipulated rate spread, the ***220** Parties cite certain testimony and exhibits of NWIGU witness Donald W. Schoenbeck (Exhibit Nos. ___ (DWS-1T) and ___ (DWS-3)), the testimony of Staff witness Yohannes Mariam (Exhibit No. ___ (YKGM-1T). pages 20-23), the testimony of Staff witness Joelle Steward (Exhibit No. ___ (JRS-1T). pages 20-22), and certain testimony and exhibits of Company witness Jon T. Stoltz (Exhibit Nos. ___ (JTS-10T) and ___ (JTS-15).

17. *Rate Design.*

a. *Transportation Customers.* With respect to Rate Schedules 663 and 664, Staff, the Company and NWIGU agree to the following:

(i) Rate Schedules 663 and 664 shall be consolidated into one rate schedule.

(ii) Such consolidated rate schedule shall have two options whereby the customer may elect firm service. Under the first option, the customer agrees to pay a demand charge of fifteen cents (15[) per therm of contract demand per month, plus four declining block rates for volumetric charges. Under the second option, the availability of which is limited to customers with a minimum annual load factor of thirty-three percent (33%). the customer agrees to pay a volumetric demand charge of $0.0156 per therm. plus the four declining block rates for volumetric charges.

The block rates for volumetric usage are as follows:

First 100,000 therms	$0.05350 per therm
Next 200,000 therms	$0.01800 per therm
Next 200,000 therms	$0.01000 per therm
Over 500,000 therms	$0.00350 per therm

(iii) With respect to lost and unaccounted for gas on the distribution system, transportation customers shall be responsible for supplying additional customer-owned gas as fuel-in-kind rather than assigning the current cost of supply to transportation customers. The current five-year average lost and unaccounted for gas on the distribution system is 0.41%. Cascade will update its five year average lost and unaccounted for gas calculation in its annual purchased gas adjustment (PGA) filing.

****27** (iv) The existing 50,000 therm restriction contained in Cascade's Unbundled Distribution System Transportation Service Rules, Rule No. 20, shall be eliminated, and replaced with provisions requiring transporters to keep their nominations and deliveries within the same tolerance band as Northwest Pipeline.

5p

b. *Basic Charges.* Staff, the Company. Public Counsel NWEC and The Energy Project agree that the monthly basic charge for each rate schedule shall be as follows:

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Schedule 503 (Residential)	No change ($4.00)
Schedule 504 (Commercial)	Increase from $7.00 to $10.00
Schedule 505 (Industrial)	Increase from $12.00 to $24.00
Schedule 511 (Large Volume)	Increase from $22.00 to $44.00
Schedule 512 (Compressed)	Increase from $7.00 to $14.00
Schedule 570 (Interruptible)	Increase from $22.00 to $44.00
Schedule 577 (Ltd. Interruptible)	Increase from $22.00 to $44.00

5p

c. *Other Rate Design Changes*. Staff and the Company agree that the blocks for schedules 504, 505, and 511 shall he flattened in the manner shown on Exhibit No. ___ (JTS-9), Schedule 7, pages 16-18. No Party other than Staff, the Company, NWIGU, NWEC. The Energy Project, and Public Counsel takes a position with respect to rate design issues in this proceeding. No Party will take a position in this proceeding with ***221** respect to rate design that is contrary to or inconsistent with this paragraph 17.

d. *Evidentiary Support*. As evidentiary support for these stipulated rate design changes, the Parties cite certain testimony and exhibits of NWIGU witness Donald W. Schoenbeck (Exhibit Nos. ___ (DWS-1T) and ___ (DWS-3)), the testimony of Staff witness Joelle Steward (Exhibit No. ___ (JRS-1T). pages 23-24). and certain testimony and exhibits of Company witness Jon T. Stoltz (Exhibit Nos. ___ (JTS-1T), ___ (JTS-9), ___ (JTS-10T) and ___ (JTS-15).

18. *Safety and Reliability Infrastructure Adjustment Mechanism ('SRIAM')*. The Company shall withdraw its SRIAM proposal from consideration in this proceeding. In the event the Commission approves in the currently pending Puget Sound Energy ('PSE') electric rate case (Docket No. UE-060266) the 'depreciation tracker' proposed by PSE or a similar mechanism, the Company reserves the right in a subsequent single-issue filing to seek to implement a mechanism similar to that approved for PSE.

19. *Supporting Testimony*. If requested by the Commission, the Parties shall present a panel with a representative of each Party to describe the terms of this Settlement Agreement, respond to cross-examination from any non-settling parties, and answer questions from the Commissioners and the presiding Administrative Law Judge.

20. *General Provisions*.

a. The Parties agree that this Settlement Agreement (subject to the limitations regarding agreement on individual stipulated recommendations, as described above) is in the public interest and would produce rates for the Company that are fair, just, reasonable and sufficient. The Parties agree to support this Settlement Agreement, to the extent and manner described above, as a settlement of the contested issues for purposes of this proceeding. The Parties understand that this Settlement Agreement is not binding on the Commission in ruling on the Company's rate filing.

****28** b. The Parties agree that this Settlement Agreement represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Settlement Agreement shall not be admissible as evidence in this or any other proceeding.

c. The Parties have negotiated this Settlement Agreement as an integrated document. Accordingly, the Parties recommend that the Commission adopt their respective portions of this Settlement Agreement (to the extent and in the manner described above) as a resolution of the contested issues in this proceeding.

d. The Parties shall cooperate in submitting this Settle-

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ment Agreement promptly to the Commission for acceptance, and shall cooperate in developing any supporting testimony or narrative relating to their positions that may be required by WAC 480-07-740 (2)(b). The Parties agree to support the Settlement Agreement (to the extent and manner described above) throughout this proceeding, provide witnesses to sponsor such a Settlement Agreement at a Commission hearing, and recommend that the Commission issue an order adopting the settlements contained herein (subject to the limitations regarding agreement on individual stipulated recommendations, as described above). In the event the Commission rejects this Settlement Agreement, the provisions of WAC 480-07-750(2)(a) shall apply. In the event the Commission accepts the Settlement Agreement upon conditions not proposed herein, each Party reserves the right, upon written notice to the Commission and all parties to this proceeding within five (5) days of the Commission's order, to state its rejection of the conditions. In such event, the Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for completion of the case pursuant to WAC 480-07-750(2)(a). The Parties agree to cooperate in the development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating***222** in hearings and preparing briefs and the needs of the Commission with respect to other matters that may be pending before the Commission.

e. The Parties enter into this Settlement Agreement to avoid further expense, inconvenience, uncertainty and delay. By executing this Settlement Agreement, neither Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed in arriving at the terms of this Settlement Agreement, nor shall either Party be deemed to have agreed that any provision of this Settlement Agreement is appropriate for resolving issues in any other proceeding.

f. This Settlement Agreement may be executed in counterparts and each signed counterpart shall constitute an original document.

This SETTLEMENT AGREEMENT is entered into by each Party as of the date entered below.
DATED: October 10, 2006. *Cascade Natural Gas Corporation* By James M. Van Nostrand Perkins Coie LLP Attorney for Cascade Natural Gas Corporation *Staff of the Washington Utilities and Transportation Commission* By Gregory J. Trautman Assistant Attorney General *Northwest Industrial Gas Users* By Edward A. Finklea Cable Huston Benedict Haagensen & Lloyd, LLP Attorney for Northwest Industrial Gas Users
****29** *The Energy Project* By Brad M. Purdy Attorney for The Energy Project
NW Energy Coalition By Nancy Glaser
Cost Management Services, Inc. By John Cameron Davis Wright Tremaine Attorney for Cost Management Services, Inc.
Office of the Attorney General Public Counsel Section By Judith Kerbs Assistant Attorney General

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***224** *Attachment B*

Settlement Agreement, Docket No. UG-060256

This document comprises Attachment B to the Settlement Agreement of October ___, 2006, among parties to the general rate proceeding captioned *Washington Utilities & Transportation Commission v. Cascade Natural Gas Corporation*, Docket No. UG-060256.As part of their settlement of Docket No. UG-060256, Cascade Natural Gas Corporation ('Cascade') and Cost Management Services, Inc. ('CMS'), hereby agree to the following statements regarding the documents specified below, each of which shall be included as part of the statement of stipulated facts for use by parties to the separate complaint proceeding captioned *Cost Management Services. Inc., v. Cascade Natural Gas Corporation*, WUTC Docket No. UG-061256, which shall proceed irrespective of the settlement of Docket No. UG-060256:

1. All information contained in the documentation comprising CMS cross-examination exhibit 84 in Docket

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No. UG-060256 is true and correct.

2. All information contained in the documentation comprising CMS cross-examination exhibit 85C in Docket No. UG-060256 is true and correct.

3. All information contained in the documentation comprising CMS cross-examination exhibit 86 in Docket No. UG-060256 is true and correct.

4. All information contained in the documentation comprising CMS cross-examination exhibit 87 in Docket No. UG-060256 is true and correct.

5. The attached document, entitled 'Areawide Public Utility Contract for Gas services, Contract No. GS-00P-95-0006 between the United States of America and Cascade Natural Gas Corporation,' (a) was duly executed by the United States of America and Cascade Natural Gas Corporation, (b) is a public document, (c) is a true and correct copy of what it purports to be.

6. Cascade Natural Gas Corporation has executed contracts for the sale of natural gas to end-use customers with facilities located within the WUTC-certificated service territories of Avista Utilities and Puget Sound Energy, and is currently selling natural gas pursuant to such contracts. Such contracts include, but are not limited to, the contract between the United States of America and Cascade Natural Gas Corporation, described in Stipulated Fact No. 5, above.

7. The attached document, entitled 'Petition For Determination That Cascade Does Not Require Certificate of Public Convenience And Necessity For Services Described In Rate Schedule 700,' is a true and correct copy of a public document filed by Cascade Natural Gas Corporation in WUTC Docket No. UG-001119.

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***226** FOOTNOTES

FN1 A glossary of acronyms and terms used in this Order is attached for the convenience of readers.

FN2 While Judge Wallis conducted the prehearing conference, Administrative Law Judge Karen Caill" was the assigned presiding officer for this proceeding. In June, the matter was reassigned to Administrative Law Judge Ann E. Rendahl, who presided over the remainder of the proceeding.

FN3 In formal proceedings, such as this case, the Commission's regulatory staff functions as an independent party with the same rights, privileges, and responsibilities as any other party to the proceeding. There is an ' *ex parte* wall' separating the Commissioners, the presiding Administrative Law Judge, and the Commissioners' policy and accounting advisors from all parties, including advocacy Staff. RCW 34.05.455.

FN4 Parvinen, Exh. No. 361-T at 5.

FN5 We resolve the issues identified in CMS' complaint against Cascade in Order 03 in Docket UG-061256 entered concurrently with this Order.

FN6 *See* Exh. No. 491.

FN7 WAC 480-07-750(2).

FN8 WAC 480-07-740.

FN9 WAC 480-07-750(1).

FN10 *Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-032065, Order 06 at 26, £ 59 (October 2004) [Hereinafter *WUTC v. PacifiCorp*, Docket UE-032065, Order 06].

FN11 *Id.*, £ 61.

FN12 *Id.*, £ 62.

FN13 *See* Cascade Initial Brief, ££ 11-12; Staff Reply Brief, ££ 18-19.

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FN14 Cascade Initial Brief, £15.

FN15 Exh. No. 1, £ 12(d), Att. A.

FN16 *Id.*, £ 12(c); Exh. No. 2, £ 7.

FN17 Cascade Initial Brief, £ 22.

FN18 Stoltz, Exh. No. 21-T at 7:3-10.

FN19 Parvinen, Exh. No. 361-T at 11:9-17.

FN20 *Id.* at 11:9-14; see also Parvinen, Exh. No. 366.

FN21 Lehmann, Exh. No. 341-T at 3:24 - 4:11.

FN22 CMS Complaint, ££ 9-18, 33-39.

FN23 *Id.*, ££ 19-32.

FN24 CMS Answer to Cascade's Cross-Motion for Summary Determination at 7-10.

FN25 Stoltz, Exh. No. 30-T at 3:3 - 5:23.

FN26 Exh. No. 1, £ 12(b)(ii).

FN27 *Id.*, £ 12(b)(iii) and (iv).

FN28 Cascade Initial Brief at 9.

FN29 *Cost Management Services, Inc. v. Cascade Natural Gas Corp.*, Docket UG-061256, Order 03, £ 48 (Jan. 16, 2007).

FN30 *Id.*, ££ 61, 63.

FN31 *Id.*, ££ 56, 91.

FN32 *Id.*, ££ 66, 92.

FN33 *Id.*, ££ 66, 93-95.

FN34 *Id.*, ££ 97-98.

FN35 Parvinen, Exh. Nos. 361-T, 362, 363, 364, 366, 367; Stoltz, Exh. Nos. 21-T, 26, 30-T, 31; Barnard, Exh. Nos. 91-T and 92;*See* Exh. No. 1, ££ 12(d), (e).

FN36 Stoltz, Exh. No. 21-T at 14-18.

FN37 Parvinen, Exh. Nos. 361-T at 22-25 and 365; Weiss, Exh. No. 311-T at 29; Lazar, Exh. No. 281-T at 36; Eberdt, Exh. No. 351-T at 11.

FN38 Stoltz, Exh. No. 30-T at 32-35.

FN39 Exh. No. 1, £ 13.

FN40 *See, supra*, nn.36-38; see also Cascade Initial Brief, £ 23.

FN41 Energy Project Brief at 1-2.

FN42 Stevens, Exh. No. 11-T at 9-10.

FN43 Eberdt, Exh. Nos. 351-T at 3-7 and 352-T at 2-4; Lazar Exh. No. 281-T at 39-40; Parvinen, Exh. 361-T at 20-21.

FN44 Stevens, Exh. No. 12-T at 6-7.

FN45 Energy Project Brief at 3.

FN46 Stoltz, Exh. No. 21-T at 18-19.

FN47 Mariam, Exh. No. 441-T at 21:11 - 22:13; Schoenbeck, Exh. No. 231-T at 8:17 - 9:17; Lazar Exh. No. 281-T at 10:5 - 11:15.

FN48 Steward, Exh. No. 421-T at 20-21; Lazar, Exh. No. 285-T at 41; Schoenbeck, Exh. No. 231-T at 10.

FN49 Mariam, Exh. No. 441-T at 21:17 - 23:8; Schoenbeck, Exh. Nos. 231-T at 9:18 - 12:9 and 233; Lazar, Exh. No. 285-T at 15:13 - 16:5.

FN50 Stoltz, Exh. No. 30-T at 25-29.

FN51 Stoltz, Exh. No. 21-T at 19.

FN52 Steward, Exh. No. 421-T at 24; Lazar, Exh. No. 281-T at 22-24; Eberdt, Exh. No. 351-T at 10-11.

FN53 Schoenbeck, Exh. No. 231-T at 13-16.

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FN54 Stoltz, Exh. No. 30-T at 27, 32.

FN55 Because of our general policy in favor of settlements, we accept the parties' agreement concerning basic service charges. However, we believe sound public policy requires that a reasonable balance be struck between a utility recovering its fixed costs via fixed rather than volumetric charges. A rate design that provides for a utility to recover a disproportionate amount of its fixed costs in volumetric rates fails to recognize the importance of reflecting in rates the nature of fixed costs incurred to provide utility service. When Cascade next files a general rate case, we require the Company to base its filing on a transparent cost-of-service study that follows the Commission's guidelines for such studies. A properly prepared study will be a useful tool in considering the appropriate balance for recovering fixed and volumetric charges.

FN56 Stoltz, Exh. No. 30-T at 32.

FN57 Parvinen, Exh. No. 351-T at 27-30; Brosch, Exh. No. 251-T at 3, 8, 25; Schoenbeck, Exh. No. 231-T at 2, 6.

FN58 Cummings, Exh. No. 221-T at 2-4, 14-15.

FN59 We calculate the difference as follows: [(Company rate of return - Staff rate of return) times Company rate base] divided by the conversion factor: [(.0937-.0833)*239,332,551]/.631369.

FN60 Morin, Exh. No. 161-T at 53:7-23; McArthur, Exh. No. 191-T at 2-5.

FN61 Parcell, Exh. No. 391-T at 37:13 - 39:2.

FN62 *Id.*, at 17:5-6; see also Parvinen, Exh. No. 361-T at 3:9-13, where Staff uses the 8.33 rate of return in its revenue requirement recommendation to reflect that Staff recommends a decoupling mechanism.

FN63 Staff and the Company are the only parties that filed testimony concerning the cost of capital and capital structure.*See, supra*, paragraphs 56-57.

FN64 Exh. No. 2, £5.

FN65 Cascade Initial Brief, £18; Staff Responsive Brief, £23.

FN66 Public Counsel Initial Brief at 49.

FN67 *Id.* at 50-51.

FN68 Public Counsel cites erroneously to RCW 80.04.140 (Orders requiring joint action by two or more public service companies) for this proposition. Public Counsel also offers a citation to a 1997 telecommunication order for the quoted language. Cascade asserts in reply that the law cited and the telecommunication case involve RCW 80.36.140 - telecommunication law that does not apply to natural gas or electricity companies.*See* Cascade Reply Brief, n. 38.

FN69 Public Counsel Reply Brief at 24-25.

FN70 *See, supra*, ££ 22-25.

FN71 *See Washington Utilities and Transportation Commission v. Northwest Natural Gas Company*, Docket UG-031885, Order 04 £ 8 (June 23, 2004).

FN72 *See WUTC v. PacifiCorp*, Docket UE-032065, Order 06 £ 24.

FN73 *See Washington Utilities and Transportation Commission v. Avista Corporation* , Dockets UE-011514 and 011595, Fourth Supplemental Order £ 23 (Mar. 4, 2002).

FN74 Staff Reply Brief at 9; Company Reply Brief at 10-12.

FN75 Exh. No. 1, £ 12(a); Exh. No. 2, £5; Staff Reply Brief, £ 20; see also Staff and Cascade's

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Responses to Bench Request No. 4, in which they concur that: 'Using the evidence set forth in the Settlement Agreement, ...the parties agreed on net income available for return before adjustments are made for the items listed in Attachment A to the Agreement. ...[The] net income for return [is estimated] to be $20,484,254 (net income per books plus the settlement 'revenue requirement of $7,480,632 with respect to return' adjusted to net income by the conversion factor). Applying this net income to the settlement rate base of $231,493,760 yields an overall return of 8.85 percent.'

FN76 For example, in *WUTC v. PacifiCorp*, Docket UE-032065, Order 06 £ 24, the Commission observed that the overall rate of return specified in a settlement 'would establish a benchmark against which the Company's future performance can be measured.' This settlement included only a rate of return with no detail on return on equity or capital structure.

FN77 Staff Initial Brief at 9-10; Exh. No. 2, £ 5.

FN78 Staff Initial Brief at 8; Cascade Initial Brief at 27-28, citing Morin, Exh. No. 161-T at 53:13-16, 4:24-5:2; Exh. No. 175; Parcell, Exh. No. 391-T at 3:18-22; 38:13-16.

FN79 Cascade Initial Brief at 28-30, citing Exh. No. 317, the Christensen Associates Energy Consulting study of the Northwest Natural Gas Company (NW Natural) decoupling mechanism approved in Oregon. The Company argues that the decoupling mechanism included in the settlement is narrower in scope than the NW Natural mechanism in Oregon and would be expected to have a smaller effect on risk.*Id.* at 28-30.

FN80 Staff Initial Brief, £ 6.

FN81 Public Counsel Initial Brief, ££ 7, 68-72.

FN82 *See* Exh. No. 1, £ 15(a)-(e).

FN83 The term 'margin' refers to the revenue necessary for a utility to recover its total cost of service net of purchased gas expenses and other expenses treated as 'flow-through' items in rates (*e.g.*, revenue taxes, conservation program riders).*See* Steward, Exh. No. 421 at 3, n.1. A utility's per customer margin revenue is simply its total cost of service, as determined in the most recent general rate case, divided by the number of customers.

FN84 *See* RCW 80.28.024, RCW 80.28.025, RCW 80.28.260.

FN85 The Commission has determined that it is not desirable to take a blanket approach to decoupling. 'The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking.' Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

FN86 Public Counsel Initial Brief, £ 91.

FN87 *Id.*, ££ 22-28, 56-59.

FN88 *See* Steward, Exh. No. 421-T at 19:19-20:1.

FN89 Public Counsel Initial Brief, ££ 7, 68-72.

FN90 Weiss, Exh. No. 311-T at 7:9-11.

FN91 *See* Exh. No. 1 at 39, £ 15(e)(ii).

FN92 Steward, Exh. No. 421-T at 19:7-10.

FN93 Cascade Initial Brief, £ 32.

FN94 Public Counsel Initial Brief, ££ 60-67, 80, 85-86, 93.

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FN95 Weiss, Exh. No. 311-T at 5:17-21, 12-19-21, 14:15-19, 21:11-13, 31:3-5; Steward, Exh. No. 421-T at 17:4-7; *see also* Public Counsel Initial Brief, ¶¶ 58-61, 66.

FN96 Weiss, Exh. No. 311-T at 31:3 - 34:19.

FN97 Stevens, TR. 223:25 - 225:17.

FN98 Cascade Reply Brief, ¶¶ 18-19; NWEC Reply Brief at 5-6.

FN99 WAC 480-07-700.

FN100 *See, supra*, nn.95-97.

FN101 *See* Exh. No. 1 at 39, ¶15(e)(ii) (emphasis added).

FN102 *WUTC v. PacifiCorp*, Docket UE-032065, Order 06 ¶ 61.

FN103 *Id.*, ¶ 62.

**30 *228 EDITOR'S APPENDIX

PUR Citations in Text

WASH.] Washington Utilities & Transp. Commission, 236 PUR4th 485,Docket No. UE-032065,Order No. 6, Oct. 27, 2004.

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Re Avista Corporation, dba Avista Utilities
Docket UG-060518
Order 04

Washington Utilities and Transportation Commission
February 1, 2007

APPEARANCES: David Meyer, attorney, Spokane, Washington, represents Avista Corporation (Avista). Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of the Attorney General (Public Counsel). Greg Trautman, Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff). Ron Roseman, attorney, Seattle, represents intervenor The Energy Project. Nancy Glaser, Seattle, represents Intervenor The Northwest Energy Coalition, and Ed Finklea and Chad Stokes, attorneys, Portland, represent Intervenor Northwest Industrial Gas Users, or NWIGU.

Before Sidran, chairman, Oshie and Jones, commissioners, and Wallis, Administrative law judge.

BY THE COMMISSION:

ORDER 04

FINAL ORDER APPROVING DECOUPLING PILOT PROGRAM

***1** *Synopsis: The Commission grants Avista's request for approval of a decoupling mechanism pilot program, and requires an analysis of the pilot program's results. The Order accepts a proposed multiparty settlement, subject to conditions limiting accumulation of interest and carry-over of benefits between periods, and denies requests by other parties to reject the proposal.*

NATURE OF PROCEEDING. Docket UG-060518 involves a petition by Avista Corporation for authority to implement a mechanism to decouple its rates for conducting business operations, in part, from its rates for commodity sales.

MULTIPARTY SETTLEMENT: All parties except Public Counsel and The Energy Project have settled their differences and propose a settlement of all issues. Public Counsel and The Energy Project oppose the proposal.

HEARING AND BRIEFING. The Commission convened an evidentiary hearing in the proceeding on December 22, 2006. The parties submitted prehearing briefs on December 14, 2006, and presented closing arguments at the conclusion of the evidentiary hearing.

DECISION. The Commission finds that the benefits of this pilot program sufficiently outweigh its potential disadvantages and should be approved. The pilot program, supported by Staff as well as industrial and environmental interests, will allow a test of decoupling from which the parties can obtain objective data and analysis. The proposal is of relatively small scale and includes provisions to ameliorate the minor risk to ratepayers.

BACKGROUND

Decoupling is a ratemaking and regulatory tool intended to break the link between a utility's recovery of fixed costs and a consumer's energy consumption by reducing the impact of energy consumption on a utility's recovery of its fixed costs. Conservation advocates view decoupling as an important tool to promote greater conservation efforts by the utility by removing financial discentives.

Under traditional ratemaking structures, utilities recover a large portion of their fixed costs through charges based on the volume of energy that consumers use. Consequently, a reduction in energy consumption may lower the probability that the utility can fully recover its fixed costs. Energy consumption may be lower for a variety of reasons. Consumers may lower their thermostats or take shorter showers. More energy efficient

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building codes and appliances, better and more efficient insulation, and warmer than normal weather can also reduce energy use. Conversely, an increase in energy consumption may lead to a utility over-recovering its fixed costs. The traditional financial incentives rewarding higher sales, some argue, create an environment in which utilities do not support conservation because it is inconsistent with their economic interests.

Promoting energy conservation is a goal that we strongly support, and provides a highly appealing rationale for decoupling on its face. Our states' laws and policies encourage us to look with favor upon incentives to stimulate increased energy conservation as well. [FN1] Our statutory responsibility to regulate in the public interest, however, requires us to look beyond the abstract and examine the specific evidence to determine whether the facts support this rationale for Avista. [FN2]

***2** Some of the parties to this proceeding reached agreement on all disputed issues. The settling parties are the Company, the Commission Staff, NWIGU, and the NWEC, (the Northwest Environmental Coalition), collectively the 'Joint Parties.' [FN3] Along with the Northwest Industrial Gas Users (NWIGU) they support adoption of a three-year pilot 'partial' decoupling mechanism that they propose as a multiparty settlement. [FN4]

Public Counsel and the Energy Project oppose the proposal.

STANDARDS FOR REVIEWING SETTLEMENT AGREEMENTS

The Commission's procedural rules govern the process for reviewing proposed settlement agreements. The Commission 'may accept [a] proposed settlement, with or without conditions, or may reject it.' [FN5] The Commission must 'determine whether a proposed settlement meets all pertinent legal and policy standards. ' [FN6] The Commission may approve settlements 'when doing so is lawful, when the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the Commission.' [FN7]

In reviewing the proposed settlement, we must consider the terms of the decoupling proposal, and whether those terms are lawful, are supported by the record and are in the public interest.

TERMS OF THE PROPOSED SETTLEMENT

The main features of this proposed pilot decoupling mechanism include the following: [FN8]
• *Term*: It would begin January 1, 2007. Recording of deferred revenue will end on June 30, 2009. However, the amortization period would begin on November 1, 2007 and end on October 31, 2010. • *Application*: It would apply only to schedule 101 (residential and small commercial customers).• *New Customer Adjustment*: It would remove the usage associated with new customers added since the corresponding month of the test year. • *The Deferral Amount*: It would defer 90% of the margin difference, either positive or negative, for later recovery (or rebate).• *Recovery*: It would subject recovery of deferred costs to: • *An earnings test* - Avista could not earn more than its authorized 9.11% rate of return. • *A demand side management (DSM) test* - recovery based on Avista achieving specific conservation targets.

Actual vs. Target DSM Savings	Amount Deferred
< 70%	0%
> 70% and < 80%	60%
> 80% and < 90%	70%

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> 90% and < 100%	80%
100%	90%

• Any deferred amount not recovered due to the earnings or DSM tests would carry over and offset future deferrals. [FN9] • Variations due to weather will be excluded from calculations of savings. • *Review of DSM Savings*: The Company will retain an independent third party to audit the results of DSM savings reported for decoupling purposes. • *Annual Rate Changes*: The mechanism would limit annual rate increases due to the mechanism to 2% annually. • *Decoupling Evaluation*: Prior to filing a request to continue the mechanism beyond its initial term, the company must evaluate its results.

*3 According to the Joint Parities, the stipulated decoupling mechanism would 'break the link between the volume of therm sales and the recovery of fixed costs and would provide for an increased focus on energy efficiency and conservation.' They argue that the resulting 'increased conservation would not only benefit the individual customers participating in those measures through reduced bills, but would also reduce the overall demand for natural gas, which would help to reduce natural gas prices for all customers.' [FN10] The Joint Parties further assert that the proposed decoupling mechanism 'would align the Company's interest with that of its customers with an increased focus on effective DSM programs.' [FN11]

Decoupling, like many other departures from traditional ratemaking structures that have come before this Commission, has both potential advantages and disadvantages. A key disadvantage, as Public Counsel points out, is the potential shifting of risk to ratepayers. [FN12]Under the stipulated proposal, the risks of changes to weather-normalized consumption would shift to customers. All customers, regardless of their individual efforts to lower use, will experience a surcharge in rates should consumption by class fall below the expected level. This points us to a second potentially serious problem - the distortion of price signals and consequent dampening of customer conservation initiatives.

Balancing fixed-cost recovery on an annual basis via a surcharge or credit mechanism diminishes the value of rates as a means to send appropriate price signals to customers. Based on changing energy market conditions, price signals undoubtedly affect customer choices to conserve or not. This price signal may be weakened if customers conserve and then are faced with paying a surcharge that reduces their financial benefit. In those circumstances, decoupling actually may prove counterproductive to its laudable purpose. Just as we must be concerned that in some instances the absence of decoupling or something similar may prove a disincentive to a company promoting conservation, the implementation of decoupling, and associated surcharges, may prove a disincentive to customers who might be inclined to conserve if it is to their financial advantage.

A third potential problem, vigorously argued by Public Counsel, is the risk over time of distorting the 'matching principle' through single issue ratemaking. [FN13]Under this principle, revenues and costs are balanced at a common point in time, i.e., a rate case, to determine fair, just, reasonable and sufficient rates. If a company is largely assured recovery of fixed costs and most variable costs are routinely passed through to customers (e.g., via purchased gas adjustment mechanisms and the like), then the company has fewer reasons to file a general rate case. In this context, any cost savings achieved by the company are not shared with customers. The result risks over-earning by the company and overpaying by the customers.

*4 Considering these concerns, we must examine carefully the stipulated proposal to determine whether the record is sufficient to prove the potential advantages from decoupling outweigh its potential disadvantages in this case.

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A fundamental test in this regard is the likelihood of increased conservation as a result of implementing a decoupling program. A key complaint of Public Counsel and the Energy Project is that there is no guarantee that the decoupling proposal would increase conservation. Public Counsel argues that the stipulation's use of the 2006 Integrated Resource Plan's (IRP) savings level as the conservation target does not satisfy the 'requirement for incremental conservation.' FN14 The Energy Project also expresses skepticism over whether the proposed decoupling mechanism would increase conservation and recommends a higher conservation target. FN15

The Joint Parties respond that Avista performed a comprehensive assessment of natural gas efficiency measures to establish its gas savings targets as part of the IRP FN16 development process. This effort was carried out with the help of an external oversight group, the External Energy Efficiency Board. As a result, the Joint Parties claim that the savings target is 'meaningful and elevated' as well as being 'appropriate and in the public interest.' FN17 The Joint Parties further assert that with the stipulated decoupling program, the Company can continue to encourage customers to conserve natural gas through education, as well as through programmatic DSM. FN18 Finally, the Joint Parties claim that the prospect of a decoupling mechanism has already increased the Company's focus on natural gas DSM. The Company has increased resources 'to achieve higher DSM goals in 2006 and beyond.' FN19

We note that the stipulated decoupling mechanism includes a DSM test whereby Avista must achieve *at least* the 2006 IRP's targeted savings level to maximize recovery of deferred costs. Moreover, the Joint Parties point out the 2006 IRP target was based on a comprehensive assessment of available efficiency measures and is about four times the goal of the previous 2004 IRP. FN20Finally, it appears that Avista has recently made efforts to increase its conservation program in anticipation of this decoupling mechanism. Ms. Glaser, testifying on behalf of the Northwest Environmental Council, emphatically supported this view. Together, these factors lead us to conclude that the proposed decoupling mechanism has some potential to increase Company conservation.

Public Counsel also asserts that deferrals under the decoupling mechanism would be far out of proportion to the lost margins from Avista's energy efficiency programs. Of the $617,000 deferral simulated by the Company for the July 2005-June 2006 time period, it alleges that only $141,000 (less than 25 percent) was due to Avista's own conservation efforts. FN21The Joint Parties argue that Public Counsel 'fails to recognize that the [decoupling] mechanism is intended to capture up to 90 percent of the lost margin resulting from all reductions in usage ...even conservation beyond that which results from the Company's sponsored DSM programs.' The Joint Parties further imply that some of the customer conservation results from Company education efforts.' FN22

***5** Public Counsel makes a strong argument that the decoupling mechanism may recover lost margin far out of proportion to losses from effects of Avista's efficiency programs. As noted above, we are concerned that the mechanism not simply be a way to shift from the Company to customers the risk of falling individual natural gas consumption. That said, it is reasonable to assume, as the Joint Parties do, that company-sponsored educational efforts have an effect on individual efficiency decisions. It is also reasonable to conclude that the application of an earnings cap and the exclusion of weather from the mechanism will prevent such a significant shift in risks that the Company would earn windfall profits - especially over the three-year test period proposed in the stipulation.

To ensure that the program does not result in inappropriate benefit to the Company, we require two changes to the proposal. First, any funds that are not deferred due to the 'earnings' and/or the 'DSM' test may not be carried over to the next period. Second, the Company may not record interest on deferrals until we approve the deferrals for recovery. FN23In light of these changes, we do not find Public Counsel's argument sufficiently strong to prevent implementation of the multiparty settlement. However, the proportion of margin lost to company sponsored DSM relative to the amount subject to recovery is of great interest to us, and we will

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closely scrutinize this factor in reviewing the results of this pilot decoupling program.

Public Counsel claims that eliminating schedule 111 from the decoupling mechanism creates two serious problems. First, he argues that any incentive resulting from decoupling will benefit Schedule 111 (large user) customers who will not be paying anything to remove the 'disincentive.' Second, he argues that since the settlement decoupling proposal recovers the full lost margins for all rate schedules, Schedule 101 (residential) customers are paying not only for their own lost margins, but for all Avista's lost sales volumes for all customer schedules. This, he alleges, amounts to a cross-subsidy. [FN24]

The Joint Parties respond that Schedule 111 has a significant number of large commercial and industrial customers, whose gas usage can vary greatly due to economic reasons. These customers should not be part of the pilot decoupling mechanism and it would be difficult to identify, track and remove them from the mechanism. So the Joint Parties agreed to eliminate all of Schedule 111 customers. The Joint Parties further assert that the mechanism determines lost margin only from Schedule 101 customers and any adjustment applies only to those customers. Any lost margin associated with Schedule 111 customers would not be included in the decoupling mechanism. [FN25]

We find little merit in the assertion that decoupling proposal would result in Schedule 101 customers subsidizing Schedule 111 customers. The lost margins would be calculated solely for and apply only to Schedule 101 customers. We also do not agree with the apparent argument that a cross subsidy occurs simply because the conservation tariff rider applies to all customers, but all customers may not equally share in the conservation acquired through the rider. The tariff rider creates a public benefit by providing a pool of funds to acquire the most conservation at the least cost, wherever that may occur. The argument that this creates a cross-subsidy could equally apply to other utility programs such as rate relief provided to some low-income customers.

*6 In prior reviews of proposed decoupling mechanisms, we have noted the importance of the information accompanying a general rate case to making a fully informed decision. Although this petition is not part of a general rate case, the fact that Avista had such a case before us within the past 13 months is sufficient in this context to guide our decision. [FN26]

Public Counsel raises substantive concerns as to the appropriateness of decoupling. We conclude that an appropriately designed pilot program with adequate safeguards to protect ratepayers is in the public interest, because it will test the hypothetical benefits of decoupling generally and the specifics of this mechanism set forth in the settlement agreement. This proposal, as conditioned, has many limitations and safeguards to protect the public; it follows a review adequate for the purpose in a rate proceeding decided recently; and it is low-risk, putting ratepayers to a minimal exposure. [FN27]As modified, this proposal constitutes an acceptable form for a pilot program.

To ensure an adequate review of the program and its accomplishments, we require that the program be reviewed at its conclusion in a general rate case.

CONCLUSION

The Commission favors the resolution of contested issues through settlement 'when doing so is lawful and consistent with the public interest.' [FN28] We have carefully considered the design of the stipulated partial decoupling mechanism, including the public protections afforded by the DSM test and the earnings test on recovery of deferred costs. After reviewing all of the arguments, we determine that it is in the public interest to allow the Company to proceed with this pilot program. However, we agree with Public Counsel and the Energy Project that the proposal is not without potential flaws. The settling parties should consider our approval as an opportunity to demonstrate that decoupling mechanisms do indeed increase utility sponsored conservation and that the potential flaws do not outweigh the program's benefits. We will carefully evaluate the mechanism, and will only consider an extension upon a convincing demonstration that the mechanism has enhanced Av-

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ista's conservation efforts in a cost-effective manner.

FINDINGS OF FACT

Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated above our findings and conclusions upon issues in dispute among the parties and the reasons supporting the findings and conclusions, the Commission now makes and enters the following summary findings of fact, incorporating by reference pertinent portions of the preceding detailed findings:

(1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas companies.

(2) Avista Corporation is a 'public service company' and a 'gas company,' as those terms are defined in RCW 80.04.010, and as those terms are used in RCW Title 80. Avista is engaged in Washington State in the business of supplying utility services and natural gas to the public for compensation.

*7 (3) Avista filed a petition on April 5, 2006, requesting an order authorizing a natural gas decoupling mechanism which would defer certain costs and revenues in order to potentially recover fixed costs unrelated to consumption.

(4) Four parties entered into a multi-party Agreement resolving their differences and agreeing to a pilot program. The settling parties included the Company, Commission Staff, and the Northwest Environmental Coalition (NWEC). In addition, the Northwest Industrial Gas Users (NWIGU) supports the proposed settlement. The Settlement Agreement is attached to this Order as Appendix A.

(5) Public Counsel and the Energy Project oppose the settlement proposal.

(6) The proposed pilot decoupling program includes sufficient elements, mechanisms and commitments to protect ratepayers and real incentives for the Company to deliver on the promise of conservation. It is likely to increase Company conservation.

(7) An evaluation of the pilot, partial decoupling program, regardless of whether Avista seeks to continue the program after the three-year pilot period expires, is important to determining the value of decoupling mechanisms for regulated utilities in Washington State.

CONCLUSIONS OF LAW

Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law incorporating by reference pertinent portions of the preceding detailed conclusions:

(1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, this proceeding.*RCW Title 80.*

(2) Informal settlements in administrative proceedings are encouraged.*RCW 34.05.060.* The Commission may approve settlements 'when doing so is lawful, when the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission.'*WAC 480-07-750(1).*

(3) The Settlement Agreement is supported by the record, and is consistent with the law and public interest.

(4) Avista's petition should be granted, authorizing accounting treatment effective January 1, 2007, as described in the Settlement Agreement to implement a decoupling mechanism pilot program, but only subject to the following conditions: First, any funds that are not deferred due to the 'earnings' and/or the 'DSM' test may not be carried over to the next period. Second, the Company may not record interest on deferrals until such time as the deferrals are approved for recovery by the Commission. If the parties fail to accept these conditions, this Order shall become void and Avista's petition shall be set for a full hearing on the merits.

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(5) The Commission should retain jurisdiction over the subject matter of and the parties to this proceeding to effectuate the terms of this Order.*RCW Title 80.*

ORDER

*8 The Commission approves, subject to condition, the Joint Parties' proposal and authorizes Avista to implement accounting treatment, as described in the Settlement agreement, to effect a decoupling mechanism pilot program. For the approval to become effective, the settling parties must each agree within ten business days to a settlement agreement modification containing the following changes: First, any funds that are not deferred due to either the 'earnings' and/or the 'DMS' test may not be carried over to the next period. Second, the Company may not record interest on deferrals until such time as the deferrals are approved for recovery by the Commission.

The multi-party Settlement Agreement filed in this proceeding on October 27, 2006, attached to this Order as Appendix A and incorporated herein by this reference as if set forth in full, is accepted and approved, subject to conditions, as set out in the body of this Order.

Dated at Olympia, Washington, and effective February 1, 2007.

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

APPENDIX A

PROPOSED SETTLEMENT

SETTLEMENT AGREEMENT

I. PARTIES

1. This Settlement Agreement is entered into by Avista Corporation (the 'Company'), the Staff of the Washington Utilities and Transportation Commission ('Staff'), the NW Energy Coalition ('the Coalition'), and Northwest Industrial Gas Users ('NWIGU'), jointly referred to herein as the 'Signing Parties.' The Public Counsel Section of the Washington Attorney General's Office and The Energy Project do not join in this Settlement. The Signing Parties agree this Settlement Agreement is in the public interest and should be accepted as a resolution of all issues in this docket. The Signing Parties understand this Settlement Agreement is subject to Commission approval.

II. INTRODUCTION

2. The Company filed a Petition, dated April 4, 2006, requesting the Commission to approve a proposed Natural Gas Decoupling Mechanism. The Company also provided a copy of the Petition to representatives of Public Counsel, the Northwest Industrial Gas Users, the Coalition, the Washington Energy Policy Group (Department of Community Trade and Economic Development or 'CTED') and the Spokane Neighborhood Action Program.

Workshops were held on May 17th and June 28th at the Commission's offices to discuss the Company's proposed Mechanism. Representatives of all of the aforementioned organizations were present, as well as a representative of The Energy Project. A number of different issues and alternatives were explored during these workshops. On August 7th, the Company filed an Amendment to its original Petition to address several issues raised by the other parties.

3. A prehearing conference was held on September 6, 2006, and the Coalition, NWIGU and The Energy Project were granted permission to intervene and participate along with Staff and Public Counsel.

4. After analysis of the filing, all parties commenced discussions for purposes of resolving or narrowing the contested issues in this proceeding in a settlement conference held October 16, 2006.

5. The Signing Parties have reached agreement on the issues in this proceeding and wish to present their

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agreement for the Commission's consideration. This Settlement is the product of discussions among all parties at the aforementioned workshops and settlement conferences. The Signing Parties believe that the Settlement will serve the broader interest of removing disincentives to engage in additional conservation. The Signing Parties therefore adopt the following Settlement Agreement in the interest of expediting the disposition of this proceeding.

III. AGREEMENT

6. The Signing Parties have agreed that the company's Decoupling Mechanism (hereinafter 'Mechanism') shall consist of the following:

A. *Term of Pilot Program*: The implementation of the Mechanism will begin January 1, 2007, whereupon deferred revenue entries would begin being recorded for that month. The proposed term of the Mechanism is 2 years and 6 months for the recording of deferred revenue (January 2007 - June 2009). However, the proposed amortization period would be three years, beginning on November 1, 2007 and ending on October 31, 2010.

B. *Application of the Mechanism*: The Mechanism would apply only to customers under the Company's natural gas Schedule 101.

C. *Calculation of Monthly Deferral Amount*: Following the end of each month, the actual volume of weather-corrected therm sales for the calendar month (Current Therm Sales) will be determined and compared with the weather-corrected therm sales for the corresponding month from 2004 (Base Therm Sales), the Company's most recent test year.

***9** (1.) *Adjustment for New Customer Usage* - Prior to weather-correcting actual therm sales for the month, an adjustment will be made to remove the usage associated with new customers added since the corresponding month of the test year. To the extent the Company has added customers since the test year, these new customers would increase Current Therm Sales as compared to the Base Therm Sales. The actual usage for new customers will be subtracted from the total current month usage.

(2.) *Adjustment to Weather-Correct New Usage* - Following the subtraction of usage for new customers, the net current month usage will be weather-corrected. The coefficients (usage per degree-day per customer) used to determine the weather adjustment will be the same as those used in the test year, thereby providing a true comparison of the usage between the two periods.

(3.) *Comparison of Usage Between Current Month and Test Year* - Following the adjustments for new customer usage and weather, the net Current Therm Sales for the month will be compared with the Base Therm Sales to determine the difference in therm sales. This comparison captures the effect of conservation and price elasticity for 'existing' customers since the corresponding month of the test year.

(4.) *Over/Under-Recovery of Margin Resulting From Usage Differences* - The difference in usage will then be multiplied by the approved margin rate for Schedule 101 (sales rate less purchased gas cost per therm) to calculate the fixed distribution costs that are either under-recovered or over-recovered, as compared to the test year.

(5.) *Ninety Percent (90%) of Margin Difference Deferred* - Ninety percent (90%) of the margin difference, either positive or negative, will be deferred and recorded in a separate account for later recovery (or rebate).

(6.) *Effect of Intervening General Rate Case* - If the Company files a natural gas general rate filing and the Commission issues its Order in that filing prior to June 30, 2009, the Base Therm Sales and margins resulting from that filing will be used in the Monthly Revenue Deferral Calculation for the remaining months of the pilot term. Any weather adjustment approved in that filing would be used for determining the Base Therm Sales and Current Therm Sales. The authorized rate of return in that filing would be used for the prospective application of the earnings test, as set forth below in Section E. (1.).

D. *Rate Adjustments Coincident with Annual PGA*: The

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monthly deferred revenue will be accumulated through June of each year during the term of the Mechanism. If the Mechanism is approved to be effective January 1, 2007, the Company will accumulate the monthly deferred revenue for January through June 2007. It will then file a request to implement a rate adjustment, coincident with the 2007 PGA rate adjustment, to amortize that deferred balance over a twelve-month period, subject to the 'earnings' and 'DSM' tests described below. For each of the two successive years, the Company will accumulate the deferred revenue for each July-June period, and file a request on or before September 1 to implement the appropriate rate adjustment coincident with the annual PGA. Interest would be accrued on the deferred balance at the same rate applied to the Company's PGA deferral account.

E. *Deferred Revenue Recovery Subject to Earnings and DSM Tests*: The level of deferred revenue recovery will be subject to (a) an annual *earnings test*, and (b) a *DSM test*. The tests will be calculated independently and the test resulting in the *lowest* surcharge amount would be used.

***10** (1.) *Application of Earnings Test* - The 'earnings-test' will be based on the Company's annual 'Commission-basis' operating results, which are filed with the Commission by April 30 for the previous calendar year results. If the Commission-basis rate of return for the Company's Washington gas operations exceeds 9.11%, it would reduce the amount of the proposed surcharge (amount transferred to the balancing account) to bring the rate of return down to 9.11%. (The authorized rate of return of 9.11% is derived from the Commission's Order No. 05 in Docket No. UG-050483.)If removing the *entire* deferred revenue amount from the Commission-basis results does not reduce the rate of return to 9.11%, no surcharge would be implemented. Where the amount of the surcharge is reduced as a result of the earnings test, the amount of deferred revenue *remaining* (not recovered through the surcharge) will be carried forward and used to offset future deferrals that would otherwise be recorded, rather than written off the Company's books. (*See* Attachment 1 for illustration of Earnings Test)

(2.) *Application of DSM Test* - The 'DSM test' relates to the Company achieving pre-established natural gas DSM target savings during the prior year. The Company's 2006 Integrated Resource Plan (IRP) sets forth a natural gas (Washington & Idaho) target savings level of 1,062,000 therms for each of the calendar years 2006 and 2007. [FN1]This target savings level for each year will be used for determining the level of the 2007 and 2008 surcharges; the target savings level included in the Company's 2008 IRP will be used for the 2009 surcharge. The Company will file its 2008 gas DSM goal as a tariff revision to its decoupling tariff, which will provide an opportunity for review and comment from all interested parties. The following table shows the level of the surcharge (as a percentage of the margin difference between the current year and the test year) based on the actual gas DSM savings compared to the pre-established IRP target:

Actual vs Target DSM Savings	Surcharge vs Margin Difference
<70%	0%
...70% and <80%	60%
...80% and < 90%	70%
...90% and < 100%	80%
...100%	90% (amount deferred)

If less than 70% of the target savings are achieved, the surcharge amount will be zero. DSM savings achieved between 70% and 100% of the target will result in the

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corresponding surcharge level shown in the above table. Any deferred revenue that cannot be recovered through a surcharge as a result of not meeting at least 100% of the DSM target will be carried forward and used to offset future deferrals that would otherwise be recorded. (*See* Attachment 2 for illustration of DSM Test)

F. *Independent Third Party Review of DSM Savings*: The Company will retain an independent third party to audit the results of DSM savings reported for decoupling purposes. This independent auditor will be chosen through an 'RFP' process reviewed and approved by the parties to this Settlement Agreement. The scope of the audit will include an appropriate sampling of projects to verify the work completed, the savings recorded, and a review of the engineering estimates used to estimate the savings. The cost of the audit will be funded through DSM tariff rider funds and will not exceed $35,000 per year. (The Company will change the present method of recognizing DSM savings for decoupling reporting purposes to one where all savings associated with a project are recognized at the time the entire project is completed in order to reduce the cost of the audit, and for purposes of applying the DSM test in Section E.(2) above.)

G. *Annual Two Percent (2%) Rate Change Limitation*: After applying the 'earnings' and 'DSM' tests, the amount of the rate increase resulting from the adjustment will be subject to an annual *incremental* limit of 2%, *i.e.*, the annual increase in the surcharge cannot exceed a 2% rate increase each year (cumulative of 6% over the initial term). The incremental surcharge (percentage) increase will be determined by subtracting the annual revenue amount recovered by the *present* surcharge rate from deferred revenue to be recovered through the proposed surcharge rate, and dividing that net amount by the total 'normalized' revenue for Schedule 101 for the most recent July - June period. The normalized revenue would be determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental surcharge would exceed a 2% rate increase, only a 2% increase would be implemented and any excess deferred revenue will remain in the deferred revenue account and could be recovered the following year, subject to the 2% limitation.

H. *Annual Decoupling Rate Adjustment Filing*: On or before September 1, 2007, the Company will file a proposed decoupling surcharge (or rebate) based on the amount of deferred revenue recorded for the prior January through June 2007 period. For the September 2008 and 2009 filings, the proposed rate adjustment would reflect the total deferred revenue for an entire year (July-June). The results of the 'earnings', 'DSM' and '2%' tests will be included with the filing and used to determine the amount of the rate adjustment. A proposed tariff will be included in those filings. A sample tariff for the decoupling rate adjustment is attached for illustrative purposes as Attachment 3. The Company presently files its Commission-Basis Earnings report (for the prior year) by April 30th and will file its DSM report in advance of the decoupling filing.

***11** The proposed tariff will reflect a rate adjustment that would recover the deferred revenue amount over a twelve-month period to be implemented coincident with the Company's annual PGA. If the rate adjustment is approved by the Commission, the deferred revenue amount approved for recovery or rebate will be transferred to a balancing account and the revenue surcharged or rebated during the period will reduce the deferred revenue in the balancing account. Any deferred revenue remaining in the balancing account at the end of the year, resulting from over- or under-collection, will be added to the new revenue deferrals to determine the amount of the proposed surcharge for the following year.

I. *Accounting and Quarterly Reporting for the Mechanism*: The Company will record the deferred revenue in account 186 - Miscellaneous Deferred Debits. The amount approved for recovery will be transferred into a 182.3 - Regulatory Asset account for amortization of the surcharge revenue received. On the income statement, the Company would record both the deferred revenue and the amortization of the deferred revenue through Account 407 - Regulatory Debits and Credits, in separate sub-accounts. The Company will file a

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quarterly report with the Commission showing pertinent information regarding the Mechanism. This information will include a spreadsheet showing the monthly revenue deferral calculation for each month of the current deferral period (July - most recent month), as well as the current and historical monthly balance in the deferral account.

J. *Evaluation Plan and Extension of Mechanism*: On or before March 31, 2009 (three months prior to the end of the pilot deferral term), the Company may file a request to continue the Mechanism beyond its initial term. That filing would include an evaluation of the Mechanism and any proposed modifications of the Company. Any party is free to argue that the renewal of the Mechanism is only appropriate in the context of a general rate case. The Company would bear the burden of demonstrating why the pilot program should be extended other than in the context of a general rate case.

The Company, Commission Staff, and other interested parties will develop, through a collaborative process, a draft evaluation plan to be filed with the Commission no later than December 31, 2007.

IV. EFFECT OF THE SETTLEMENT AGREEMENT AND PROCEDURE

7. *Binding on Parties*. The Signing Parties agree to support the terms of the Settlement Agreement throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Settlement Agreement contained herein. The Signing Parties understand that this Settlement Agreement is subject to Commission approval. The Signing Parties agree that this Settlement Agreement represents a compromise in the positions of the Signing Parties. As such, conduct, statements and documents disclosed in the negotiation of this Settlement Agreement shall not be admissible evidence in this or any other proceeding.

8. *Integrated Terms of Settlement*. The Signing Parties have negotiated this Settlement Agreement as an integrated document. Accordingly, the Signing Parties recommend that the Commission adopt this Settlement Agreement in its entirety. Each Signing Party has participated in the drafting of this Settlement Agreement, so it should not be construed in favor of, or against, any particular Party.

9. *Procedure*. The Signing Parties shall cooperate in submitting this Settlement Agreement promptly to the Commission for acceptance. The Signing Parties shall make available a witness or representative in support of this Settlement Agreement. The Signing Parties agree to cooperate, in good faith, in the development of such other information as may be necessary to support and explain the basis of this Settlement Agreement and to supplement the record accordingly.

***12** The Signing Parties agree to stipulate into evidence the prefiled direct testimony and exhibits of the Company, together with such evidence in support of the Agreement as may be offered at the time of the hearing on the Settlement. If the Commission rejects all or any material portion of this Settlement Agreement, or adds additional material conditions, each Signing Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the date of the Commission's ; Order, to withdraw from the Settlement Agreement. If any Signing Party exercises its right of withdrawal, this Settlement Agreement shall be void and of no effect, and the Signing Parties will support a joint motion for an expedited procedural schedule to address the issues that would otherwise have been settled herein.

10. *No Precedent*. The Signing Parties enter into this Settlement Agreement to avoid further expense, uncertainty, and delay. By executing this Settlement Agreement, no Signing Party shall be deemed to have accepted or consented to the facts, principles, methods or theories employed in arriving at the Settlement Agreement, and except to the extent expressly set forth in the Settlement Agreement no Signing Party shall be deemed to have agreed that such a Settlement Agreement is appropriate for resolving any issues in any other proceeding.

11. *Public Interest*. The Signing Parties agree that this Settlement Agreement is in the public interest and res-

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ults in rates which are fair, just, reasonable and sufficient.

12. *Execution.* This Settlement Agreement may be executed by the Signing Parties in several counterparts and as executed shall constitute one agreement.

Entered into this 27th day of October, 2006 *Company*: By: Signature David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs *Staff*: By: ___ Gregory J, Trautman Assistant Attorney General Counsel for Commission Staff *The NW Energy Coalition* By: ___ Nancy Glaser The NW Energy Coalition *Northwest Industrial Gas Users* By: ___ Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Entered into this 27th day of October, 2006 *Company*: By: ___ David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs *Staff*: By: Signature Gregory J. Trautman Assistant Attorney General Counsel for Commission Staff *The NW Energy Coalition* By: ___ Nancy Glaser The NW Energy Coalition *Northwest Industrial Gas Users* By: ___ Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Entered into this 27th day of October, 2006 *Company*: By: David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs *Staff*: By: Gregory J. Trautman Assistant Attorney General Counsel for Commission Staff *The NW Energy Coalition* By: Signature Nancy Glaser The NW Energy Coalition *Northwest industrial Gas Users* By: ___ Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

***13** Entered into this 27th day of October, 2006 *Company*: By: ___ David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs *Staff*: By: ___ Gregory J. Trautman Assistant Attorney General Counsel for Commission Staff *The NW Energy Coalition* By: ___ Nancy Glaser The NW Energy Coalition *Northwest Industrial Gas Users* By: Signature Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

FOOTNOTES

Order 04

FN1 *See* RCW 80.28.024, RCW 80.28.025, and RCW 80.28.260.

FN2 The Commission has determined that it is not desirable to take a blanket approach to decoupling. 'The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking.' Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005). This is the third in a recent series of decoupling proposals we have considered, including one for Puget Sound Energy, Inc., *WUTC v. Puget Sound Energy, Inc* ., Order 08, Dockets UE-060266 and UG-060267 (2007), and the other for Cascade Natural Gas, *WUTC v. Cascade Natural Gas*, Order 05, Docket UG-060256 (2007). Each proposal has unique qualities and a unique setting which has shaped our analysis and determined our decision.

FN3 Though a sponsor of the settlement stipulation, NWIGU did not sign on to the joint testimony, joint rebuttal testimony, or the prehearing brief.

FN4 WAC 480-07-730.

FN5 WAC 480-07-750(2).

FN6 WAC 480-07-740.

FN7 WAC 480-07-750(1).

FN8 *See* Exh. 15 (Settlement), ¶¶ 6A-6J.

FN9 We address this provision, and require modification, below.

FN10 *See* Exh. 10 (Joint Testimony), 7:1-15.

FN11 *Id*, 7:22-8:2.

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FN12 Public Counsel Initial Brief, £ 91.

FN13 *Id.*, ££ 22-28, 56-59.

FN14 *See* Exh. 51 (Public Counsel Testimony), 12:4-20.

FN15 *See* Exh. 60 (Energy Project Testimony), 5.

FN16 Integrated Resource Plan, a means by which utilities identify resources to meet likely future loads.*See* , WAC 480-107.

FN17 *See* Exh. 11 (Rebuttal Joint Testimony), 3:8-9, 4:17-18.

FN18 *Id*, 7:3-11.

FN19 *Id*, 7:18-8:7.

FN20 *Id*, 3:8-15.

FN21 *See* Public Counsel Pre-Hearing Brief £ 5.

FN22 *See* Joint Parties Pre-Hearing Brief £ 35.

FN23 Generally, interest on deferred amounts should be limited to instances where a utility's investors have provided a direct investment. In this instance, the deferral is the amount of money the company would have made if they had earned their authorized rate of return. Since deferral is not derived from investors' finds that are expensed or capitalized, it should also not earn interest.

FN24 *Id.* 11:12-22.

FN25 *See* Exh. 11 (Rebuttal Joint Testimony), 10:9-15.

FN26 We note in contrast our rejection of Avista's petition for a power and transmission cost update outside a general rate case. See, Order 04, docket UE-061411 (2006).

FN27 The mechanism limits annual rate increases to a maximum of 2%. Avista's study indicates that if the mechanism had been effective between July 2005 and June 2006, ratepayer exposure would have been 35 cents per month for a typical residential customer. Exh. No. 1, p.11.

FN28 WAC 480-07-700.

Appendix A

FN1 The expected cost to achieve this savings target is $2.5 million for 2006 and $3 million for 2007.

END OF DOCUMENT

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Westlaw.

H

Re Southwest Gas Corporation
Docket No. G-01551A-04-0876
Decision No. 68487

Arizona Corporation Commission
February 23, 2006

OPINION and ORDER authorizing a natural gas local distribution company (LDC) to increase its rates and charges by $49.345 million, reflecting a cost of equity of 9.50% and an average weighted cost of capital of 8.40%. The cost of equity includes a 30 basis point upward adjustment to the results of a discounted cash flow analysis in recognition of the higher risk faced by the LDC as compared to the proxy group. Capital costs are determined based on a hypothetical capital structure containing a 40% equity balance, even though the actual equity ratio of the LDC is more than 5 basis points lower. However, the commission sends a signal to the LDC that it must improve its actual capital structure by requiring the LDC to submit prior to its next rate case a re-capitalization plan explaining how it intends to achieve an equity ratio of 40%. Rates are designed to move towards cost-based rates as balanced by principles of gradualism, affordability, and conservation. Commission rejects as untenable a rate design proposal offered by the LDC that would have saddled a substantial number of residential customers with rate increases in excess of 100 percent. The base cost of gas - currently included within the tariffed rate per therm for each class - is set at zero so that the full commodity cost will be included in the purchased gas adjustor (PGA) rate. Commission finds that including the previously separate base cost of gas amount in the PGA will, once the change is explained to customers, enhance customer understanding of their bills and enable them to more easily track the separate components that go into the provision of gas service. Commission adopts a staff proposal to require the LDC to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. The LDC is authorized to change its demand charge calculation formula for large commercial customers from a coincident peak method to a non-coincident peak method. Commission finds that the non-coincident peak measurement will take some of the risk of revenue recovery out of rates while reflecting value to customers on an annual basis. Commission rejects a decoupling proposal that would have insulated the LDC from risk associated with declining gas usage through the implementation of a conservation margin tracker (CMT). The CMT would, the commission finds, provide the LDC with a guaranteed method of recovering authorized revenues - a result that neither the law nor sound public policy requires. Nonetheless, the commission encourages the LDC to work with other parties to develop an alternative decoupling mechanism for consideration in future proceedings.

Commission approves an equal sharing between ratepayers and shareholders of ongoing costs of complying with the Sarbanes-Oxley Act of 2002. It finds that the improved internal auditing controls required by Sarbanes-Oxley benefit both shareholders and ratepayers. Initial assessment and review costs associated with compliance with Sarbanes-Oxley are disallowed as nonrecurring. The cost of a management incentive compensation program are shared equally between ratepayers and shareholders based on a finding that both groups derive benefits from the goals of the incentive program. However, departing from past practice, the commission disallows the costs of a supplemental executive retirement plan. Commission finds that expenses incurred by the LDC to comply with the federal Pipeline Safety Improvement Act should be borne equally by shareholders and ratepayers, with the ratepayer share collected through a surcharge mechanism. Commission declines to adjust accumulated deferred income taxes to recognize the effect of a new Internal Revenue Service regulation that went into effect nearly a year after the end of the test year. In rejecting the proposed adjustment, which would increase rate base, the commission explains that the LDC made an entirely voluntary decision in 2002 to change its accounting methodology for self constructed assets, and that it is this voluntary decision

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that has caused the LDC to now make accounting changes due to the new IRS regulation. Moreover, the commission finds federal Energy Policy Act of 2005 will result in increase deferred taxes, and thus decrease rate base. The LDC is authorized to recover dues paid to the American Gas Association, as adjusted to exclude that portion of dues directly attributable to marketing and lobbying. However, the LDC is directed to provide in its next rate case filing a clearer picture of AGA functions and how the activities of the AGA provide specific benefits to the LDC and its Arizona customers.

P.U.R. Headnote and Classification

1.
VALUATION

s192.1
Az.C.C. 2006
[ARIZ.] Accumulated deferred income taxes - Proposed adjustment for Internal Revenue Service rule change - Grounds for rejection - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

2.
VALUATION

s281
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Rate base adjustment for completed construction not classified - Grounds for allowing.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

3.
VALUATION

s187
Az.C.C. 2006
[ARIZ.] Pipe replacement projects - Write-off for defective pipe - Rejection of proposed retroactive modification of write-off schedule - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

4.
VALUATION

s281
Az.C.C. 2006
[ARIZ.] Natural gas local distribution ***245** company - Pipe replacement projects - Write-off for defective pipe - Rejection of proposed retroactive modification of write-off schedule.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

5.
VALUATION

s275
Az.C.C. 2006
[ARIZ.] Pipe replacement projects - Write-off for defective pipe - Rejection of proposed retroactive modification of write-off schedule - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

6.
VALUATION

s281
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Summary of rate base adjustments - Approved original cost rate base - Approved fair value rate base.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

7.

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EXPENSES

s95
Az.C.C. 2006
[ARIZ.] Salaries and wages - Employees engaged in marketing activities - Partial disallowance based on estimate of time devoted to marketing - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

8.
EXPENSES

s26
Az.C.C. 2006
[ARIZ.] Sales and marketing wages - Partial disallowance based on estimate of employee time devoted to marketing - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

9.
EXPENSES

s99
Az.C.C. 2006
[ARIZ.] Wages - Annualization of test year and post-test year increases - Avoiding mismatch of revenues and expenses - Increases applied only to employees employed during test year - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

10.
EXPENSES

s48
Az.C.C. 2006
[ARIZ.] Trade association dues - American Gas Association - Partial disallowance - Removal of portion of dues directly attributable to marketing and lobbying - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

11.
EXPENSES

s88
Az.C.C. 2006
[ARIZ.] Lobbying costs - Exclusion from rates - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

12.
EXPENSES

s125
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Pipeline Safety Improvement Act of 2002 - Compliance costs - Transmission Integrity Management Program - Equal sharing between ratepayers and shareholders - Surcharge recovery mechanism.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

13.
RATES

s380
Az.C.C. 2006
[ARIZ.] Natural gas - Special factors - Pipeline Safety Improvement Act of 2002 - Compliance costs - Transmission Integrity Management Program - Equal sharing between ratepayers and shareholders - Surcharge recovery mechanism.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

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14.
EXPENSES

s28
Az.C.C. 2006
[ARIZ.] Financial reporting and auditing requirements - Federal mandates - Sarbanes-Oxley Act of 2002 - Ongoing compliance costs - Equal sharing between ratepayers and shareholders - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

15.
EXPENSES

s105
Az.C.C. 2006
[ARIZ.] Management incentive compensation - Equal sharing between ratepayers and shareholders - Recognition of benefits to both groups - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

16.
EXPENSES

s105
Az.C.C. 2006
[ARIZ.] Extra benefits - Supplemental executive retirement plan - Exclusion from rates - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

***246** 17.
EXPENSES

s49
Az.C.C. 2006
[ARIZ.] Pensions - Supplemental executive retirement plan - Exclusion from rates - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

18.
EXPENSES

s15
Az.C.C. 2006
[ARIZ.] Reasonableness - Miscellaneous expenses not necessary for provisioning of gas service - Disallowance from rates - Natural gas local distribution com- pany.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

19.
EXPENSES

s19
Az.C.C. 2006
[ARIZ.] Miscellaneous expenses not necessary for provisioning of gas service - Calculation of disallowance - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

20.
EXPENSES

s15
Az.C.C. 2006
[ARIZ.] Test of reasonableness - Presumptions - Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

21.
RATES

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s120
Az.C.C. 2006
[ARIZ.] Reasonableness - Presumptions - Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

22.
RATES

s648
Az.C.C. 2006
[ARIZ.] Practice and procedure - Evidence - Presumptions - Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

23.
EXPENSES

s125
Az.C.C. 2006
[ARIZ.] Natural gas - Test-year operations - Approved adjustments - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

24.
REVENUES

s5
Az.C.C. 2006
[ARIZ.] Natural gas - Test year adjusted operating income - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

25.
RETURN

s26.1
Az.C.C. 2006
[ARIZ.] Reasonableness - Capital structure - Hypothetical structure containing 40% equity - Need for recapitalization plan for achieving actual equity ratio of 40% - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

26.
RETURN

s26.4
Az.C.C. 2006
[ARIZ.] Reasonableness - Cost of common equity - Positions of the parties - Natural gas rate proceeding.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

27.
RETURN

s26.4
Az.C.C. 2006
[ARIZ.] Reasonableness - Cost of common equity - Estimation methodology - Primary reliance on discounted cash flow model - Other financial models used as check on reasonableness - Upward adjustment for higher risk than proxy group - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

28.
RETURN

s44
Az.C.C. 2006
[ARIZ.] Reasonableness - Factors considered - Risk - Natural gas local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

29.
RETURN

s4
Az.C.C. 2006
[ARIZ.] Jurisdiction, powers, and duties - State commission - To establish reasonable rate of return - Legal standard.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

30.
RETURN

s15
Az.C.C. 2006
[ARIZ.] Reasonableness - Legal standard - Commission powers and duties.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

31.
RETURN

s26.3
Az.C.C. 2006
[ARIZ.] Reasonableness - Cost of preferred equity - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

32.
RETURN

s26.2
Az.C.C. 2006
[ARIZ.] Reasonableness - Cost of debt - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

*247 33.
RETURN

s92
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Average weighted cost of capital - Return on fair value rate base - Reasonableness.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

34.
RATES

s373
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Authorized increase - Method of calculation.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

35.
RATES

s380
Az.C.C. 2006
[ARIZ.] Natural gas - Special factors - Proposed decoupling of revenues from sales - Conservation margin tracker - Grounds for rejection - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

36.
REVENUES

s5
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Proposed decoupling of margin from customer usage -

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Conservation margin tracker - Grounds for rejection.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

37.
AUTOMATIC ADJUSTMENT CLAUSES

s47
Az.C.C. 2006
[ARIZ.] Conservation margin tracker - Decoupling of margin from customer usage - Grounds for rejection - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

38.
CONSERVATION

s1
Az.C.C. 2006
[ARIZ.] Natural gas local distribution company - Promotion of conservation - Proposed decoupling of margin from customer usage - Grounds for rejection.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

39.
RATES

s143
Az.C.C. 2006
[ARIZ.] Reasonableness - Allocation of margin among customer classes - Factors considered - Cost of service - Affordability - Gradualism - Appropriate price signals - Conservation goals.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

40.
RATES

s373
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Allocation of margin among customer classes - Factors considered - Cost of service - Affordability - Gradualism - Appropriate price signals - Conservation goals.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

41.
RATES

s385
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Single family residential service - Increased basic monthly charge - Two-tier commodity rate - Summer/winter first block differential - Movement toward cost-based rates - Balance with principles of gradualism affordability, and conservation - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

42.
RATES

s385
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Creation of multi-family residential service class - Recognition of lower cost to serve - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

43.
RATES

s385
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Low-income residential service - Retention of basic monthly charge and winter usage discount - Local distribution company.

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Re Southwest Gas Corporation

P.U.R. Headnote and Classification

44.
RATES

s385
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Residential gas air conditioning - Increase to summer second block - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

45.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Master metered mobile home park service - Increased basic monthly and volumetric charges - Movement toward cost of service - Gradualism and fairness - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

46.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Armed ***248** forces schedule - Elimination - Transfer of customers to large general service class - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

47.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Small commercial customers - Creation of new sub-class - Mitigation of increase - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

48.
RATES

s382
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Large commercial customers - Demand charge calculation formula - Non-coincident peak method - Reduced risk of revenue recovery - Reflection of value to customers - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

49.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Gas service for compression on customer premises - Basic monthly charge increases - Movement toward cost of service - Gradualism - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

50.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Cogeneration gas service - Proposed size restriction - Grounds for denial - Local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

51.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Small essential agricultural user service - Proposed closing of tariff to new customers - Grounds for denial - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

52.
RATES

s384
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Engine gas service - Agricultural irrigation - On-peak charge increase - Potential loss of customers to electricity no bar to increase - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

53.
RATES

s382
Az.C.C. 2006
[ARIZ.] Natural gas rate design - Demand and load - Engine gas service - Agricultural irrigation - On-peak charge increase - Potential loss of customers to electricity no bar to increase - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

54.
RATES

s373
Az.C.C. 2006
[ARIZ.] Natural gas - Tariff price setting - Billing determinant calculations - Appropriate methodology - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

55.
RATES

s373
Az.C.C. 2006
[ARIZ.] Natural gas - Commodity rate - Base cost of gas set at zero - Inclusion of full commodity cost in purchased gas adjustor mechanism - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

56.
AUTOMATIC ADJUSTMENT CLAUSES

s11
Az.C.C. 2006
[ARIZ.] Purchased gas adjustor mechanism - Incorporation of full commodity cost - Elimination from base rates - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

57.
AUTOMATIC ADJUSTMENT CLAUSES

s11
Az.C.C. 2006
[ARIZ.] Purchased gas adjustor mechanism - Bank balance trigger level increase - Corresponding increase in per therm adjustment band - Natural gas local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

58.
AUTOMATIC ADJUSTMENT CLAUSES

s11
Az.C.C. 2006
[ARIZ.] Purchased gas adjustor mechanism - Monthly reports - Officer certification requirement - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

59.
AUTOMATIC ADJUSTMENT CLAUSES

s59
Az.C.C. 2006
[ARIZ.] Practice and procedure - Purchased*249 gas adjustor mechanism - Monthly reports - Officer certification requirement - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

60.
PAYMENT

s62
Az.C.C. 2006
[ARIZ.] Security for payment - Customer deposits - Interest rate - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

61.
SERVICE

s332
Az.C.C. 2006
[ARIZ.] Customer service - Schedule for service - Four-hour service window - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

62.
RATES

s125
Az.C.C. 2006
[ARIZ.] Affordability - Customers with financial difficulties - Voluntary contributions by other customers - Energy Share program - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

63.
PAYMENT

s17
Az.C.C. 2006
[ARIZ.] Billing and collections - Customers with financial difficulties - Voluntary contributions by other customers - Energy Share program - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

64.
EXPENSES

s119.1
Az.C.C. 2006
[ARIZ.] Research and development - Contributions to Gas Technology Institute and other research entities - Recovery through surcharge - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

65.

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RATES

s380
Az.C.C. 2006
[ARIZ.] Natural gas - Special factors - Contributions to Gas Technology Institute and other research entities - Recovery through surcharge - Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

66.
CONSERVATION

s1
Az.C.C. 2006
[ARIZ.] Natural gas - Demand-side management - Energy efficiency programs - Low-income energy conservation - Funding level - Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

67.
EXPENSES

s19
Az.C.C. 2006
[ARIZ.] Demand-side management - Energy efficiency programs - Low-income energy conservation - Funding level - Natural gas local distribution company.

Re Southwest Gas Corporation

APPEARANCES: Mr. Andrew W. Bettwy, Ms. Karen S. Haller and Mr. Justin Lee Brown, on behalf of Southwest Gas Corporation; Mr. Scott S. Wakefield, on behalf of the Residential Utility Consumer Office; Mr. Walter Meek, on behalf of the Arizona Utility Investors Association; Mr. Peter Q. Nyce, Jr., on behalf of the United States Department of Defense; Mr. Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and Natural Resources Defense Council; Ms. Laura Sixkiller, ROSHKA, DEWULF & PATTEN, PLC, on behalf of Tucson Electric Power Company; and Mr. Jason Gellman and Ms. Diane Targovnik, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

Before Hatch-Miller, chairman, and Mundell, Spitzer, Gleason, and Mayes, Commissioners, and Nodes, administrative law judge.

BY THE COMMISSION:

**1 *OPINION AND ORDER*

On December 9, 2004, Southwest Gas Corporation ('Southwest Gas' or 'Company ') filed with the Arizona Corporation Commission ('Commission') an application for a rate increase.

On January 7, 2005, the Commission's ***250** Utilities Division Staff ('Staff ') filed a Letter of Insufficiency.

On January 26, 2005, Staff filed a Letter of Sufficiency indicating that Southwest Gas' application met the sufficiency requirements outlined in Arizona Administrative Code ('A.A.C.') R14-2-103, and classifying the Company as a Class A utility.

By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.

Intervention was granted to the Residential Utility Consumer Office ('RUCO '); the Arizona Utility Investors Association ('AUIA'); the United States Department of Defense ('DOD'); Southwest Energy Efficiency Project ('SWEEP ') and the Natural Resources Defense Council ('NRDC') (collectively 'SWEEP/ NRDC'); Yuma Cogeneration Associates ('YCA'); Arizona Community Action Association ('ACAA'); Arizona Public Service Company ('APS'); and Tucson Electric Power Company ('TEP').

With its application, Southwest Gas filed the Direct testimony of Jeffrey W. Shaw, Christina A. Palacios, Steven M. Fetter, Christy M. Berger, James L. Cattanach, Vivian E. Scott, A. Brooks Congdon, Edward B.

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Gieseking, Randi L. Aldridge, Robert A. Mashas, Frank J. Hanley, and Theodore K. Wood.

Pursuant to the revised procedural schedule established by Procedural Order issued March 10, 2005, on July 26, 2005, RUCO filed the Direct testimony of Marylee Diaz Cortez, William A. Rigsby, and Rodney L. Moore; YCA filed the Direct testimony of Jeffrey L. Hoffman; AUIA filed the Direct testimony of Walter W. Meek; ACAA filed the Direct testimony of Brian Babiars (July 20, 2005); SWEEP/NRDC filed the Direct testimony of Jeff Schlegel; and Staff filed the Direct testimony of Stephen G. Hill, Jim Dorf, Dennis Rogers, Robert Miller, William Gehlen, Prem Bahl, William Musgrove, Bob Gray, and Steve Irvine.

On August 23, 2005, Southwest Gas filed the Rebuttal testimony of Ms. Palacios, Mr. Fetter, Ms. Scott, Mr. Congdon, Mr. Gieseking, Ms. Aldridge, Mr. Mashas, Mr. Hanley, Mr. Wood, William N. Moody, Marti Marek, Robert M. Johnson, and Lisa E. Moses.

On September 13, 2005, RUCO filed the Surrebuttal testimony of Ms. Diaz Cortez, Mr. Rigsby, and Mr. Moore; AUIA filed the Surrebuttal testimony of Mr. Meek; SWEEP/NRDC filed the Surrebuttal testimony of Mr. Schlegel; DOD filed the Surrebuttal testimony of Dan L. Neidlinger; and Staff filed the Surrebuttal testimony of Mr. Hill, Mr. Dorf, Mr. Rogers, Mr. Gehlen, Mr. Musgrove, Mr. Gray and Mr. Irvine.

On September 23, 2005, Southwest Gas filed the Rejoinder testimony of Ms. Palacios, Mr. Fetter, Mr. Cattanach, Ms. Scott, Mr. Congdon, Mr. Gieseking, Mr. Moody, Ms. Marek, Ms. Moses, Ms. Aldridge, Mr. Mashas, Mr. Hanley, and Mr. Wood.

On September 26, 2005, a prehearing procedural conference was conducted to address order of testimony and exhibits.

**2 The evidentiary hearing was commenced as scheduled on October 3, 2005, and additional hearing days were held on October 4, 5, 6, 7, and 11, 2005.

On October 21, 2005, Southwest Gas filed a substitute Exhibit A-50 (Annual Consumption Graph for Low Income and Non-Low Income Residential Customers) and Exhibit A-52 (information regarding the Company's Management Incentive Plan), a portion of which was submitted under seal.

On November 4, 2005, Southwest Gas filed Exhibit A-53 (compilation of regulatory commission orders from other states addressing decoupling mechanisms) and Exhibit A-54 (summary of Southwest Gas' revised position on cost of equity and rate of return).

Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/NRDC, AUIA, and Staff.

Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/ NRDC, and Staff.

On November 23, 2005, Southwest Gas filed a Supplement to its Reply Brief.

**251 Rate Application*

According to the Company's application, as modified, in the test year ended August 31, 2004 Southwest Gas had adjusted operating income of $46,775,622 on an adjusted Original Cost Rate Base ('OCRB') of $943,110,070, for a 4.96 percent rate of return. Southwest Gas requests a revenue increase of $66,898,342. Staff recommends a rate increase of $51,625,135, and RUCO recommends an increase of $48,506,079. A summary of the parties' positions [FN1] follows:

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	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			

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Adjusted Rate Base	$943,110,070	$924,927,566	$919,607,846
Rate of Return	9.24%	8.40%	8.64%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66,898,342	51,625,135	48,506,079
FAIR VALUE			
Adjusted Rate Base	$1,189,807,002	$1,418,205,879	$1,164,944,249
Rate of Return	7.32%	6.63%	6.82%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66,898,342	51,625,135	48,506,079

REVENUE REQUIREMENT

Rate Base Issues

Southwest Gas proposes an OCRB of $943,110,070 in this proceeding. Staff proposes an OCRB of $924,927,566, and RUCO recommends an OCRB of $919,607,846. Each of the disputed issues regarding rate base items is discussed below.

Deferred Income Taxes

[1] Southwest Gas has proposed an adjustment to accumulated deferred income taxes that would result in an increase of more than $21 million to the Company's rate base. According to Southwest Gas, the deferred tax adjustment is necessary due to new regulations enacted by the Internal Revenue Service ('IRS ') on August 3, 2005 which now require the Company to include in income in 2005 and 2006 the cumulative tax deduction taken under the prior uniform capitalization ('UNICAP') rules (IRS Code Section 263A) with respect to the simplified service cost method ('SSCM') for self-constructed assets (Ex. A-27, at 6). This deferred tax adjustment is necessitated by the Company's voluntary election in 2002 to change from its historical method of accounting to SSCM.

3 Southwest Gas argues that the deferred tax adjustment is proper because the new IRS regulation is known and measurable, and because the change puts the Company in a similar position to where it would have been had it not made the election in 2002. The Company claims that its position is consistent with Commission precedent granting recognition of post-test year rate base adjustments where the impact ***252 is known and measurable, and is comparable to Staff's recommendation to recognize changes to property tax expenses that are required by post-test year legislation.

Staff disputes the Company's contention that the proposed deferred tax adjustment is proper in this proceeding. Staff argues that the deferred income tax adjustment proposed by Southwest Gas is due entirely to the Company's voluntary decision in 2002 to change its accounting methodology to the SSCM (Ex. S-6, at 2; Tr. 499-500). Staff also claims that the IRS regulations cited by Southwest Gas are temporary rules and the 2005 Energy Policy Act is likely to increase the amount of the Company's deferred taxes, thereby reducing rate base and offsetting the new IRS rule.

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RUCO also opposes the Company's proposed adjustment, arguing that the IRS rule change occurred nearly a year after the end of the test year. RUCO further contends that Southwest Gas failed to include this proposal in its initial application and waited until Rebuttal testimony to propose the adjustment. RUCO also sides with Staff's argument that the IRS rules are temporary and subject to amendment before being made final. As a result, RUCO asserts that the IRS rule change does not meet the known and measurable standard employed for other post-test year adjustments.

We agree with Staff and RUCO that recognition of the new IRS regulation is not proper in this proceeding. As Staff points out, Southwest Gas made an entirely voluntary decision in 2002 to change its accounting methodology for self-constructed assets to SSCM, and it is that voluntary election that has caused the Company to now make accounting changes due to the new IRS regulation. The Company's witness, Lisa Moses, admitted that the 2005 Energy Policy Act would result in an increase in deferred taxes, and thus a decrease in the Company's rate base, but she indicated that the Company had not quantified the impact of those changes. Although Ms. Moses stated that she does not believe the Energy Policy Act would have a significant impact on Southwest Gas, the Company did not present testimony to show how the Energy Policy Act, which is an equally known and measurable change in law, could have an offsetting effect on the Company's deferred tax liability and rate base (Tr. 495-497). We also believe RUCO's point is well taken, that Southwest Gas could have presented this proposal as part of its direct case to allow other parties more time to analyze the issue prior to the hearing. As a result, we will adopt Staff's position on this issue.

Completed Construction Not Classified

**4 [2] The National Association of Regulatory Utility Commissioners' ('NARUC') Uniform System of Accounts ('USOA'), Section 106, provides the following description of the appropriate regulatory treatment for Completed Construction Not Classified ('CCNC'):
At the end of the year or such other date as a balance sheet may be required by the Commission, this account shall include the total of the balances of work orders for utility plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed utility plant accounts. (RUCO Ex. 9)

In its application, Southwest Gas proposed an adjustment to test year rate base to reflect its CCNC balance. Relying on the NARUC USOA section quoted above, RUCO argues that only work orders which have an in-service date that falls within the test year may be included in the adjustment for CCNC (RUCO Ex. 5, at 8). According to RUCO witness Rodney Moore, certain work orders that were included in the Company's CCNC adjustment were not in service by the end of the test year and should, therefore, be disallowed (RUCO Ex. 6, at 7-8).

Through her Rejoinder testimony, Company witness Randi Aldridge explained that 'the direct gas plant portion of the CCNC adjustment is plant that was serving test year customers at the end of the test year' and the proposed CCNC adjustment 'was made simply to match test year plant with test year customers ' (Ex. A-31, at 17-18). Ms. Aldridge also testified on cross-examination that although the *253 Company's work order system may have only a single in-service date for an entire project, projects such as pipe replacements are completed incrementally to minimize customer outages, but all of the plant additions included in the CCNC account reflect pipe that was used and useful during the test year (Tr. 537-538, 589).

We agree with the Company's proposed CCNC adjustment. As Ms. Aldridge's testimony makes clear, only plant that was in service providing service to customers within the test year was included in the proposed CCNC adjustment. There is no evidence contrary to the Company's assertion that such plant was used and useful during the test year and we believe the Company's treatment of these plant accounts is consistent with the NARUC USOA and prior Commission decisions.

Pipe Replacement

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[3-5] RUCO has proposed disallowance of certain requested pipe replacement projects from the Company's rate base pursuant to the terms of a prior Commission Order that addressed regulatory treatment of defective pipe [FN2] installed in the former Tucson Gas & Electric system, which was subsequently acquired by Southwest Gas. In Decision No. 58693 (July 7, 1994), the Commission adopted a Settlement Agreement between Southwest Gas, Staff, and RUCO which required Southwest Gas to write-off a certain percentage of the replacement cost of defective pipe, and provided that the pipe replacement percentage write-off amounts would decline annually until the amounts reached zero (Decision No. 58693, at 3-4; RUCO Ex. 3, at 5-6). RUCO witness Marylee Diaz Cortez testified that the Company has continued to make the required pipe replacement write-offs since the prior Decision but the Company seeks in this docket to cease certain of the write-offs (RUCO Ex. 3, at 6).

**5 In its application, Southwest Gas is requesting that the pipe write-off schedule required by Decision No. 58693 be modified to allow the affected write-offs to cease when the specific type of pipe reached an average life of 40 years. Thus, under the Company's proposal the 1960s steel pipe and the ABS pipe would no longer be subject to write-off and the scheduled write-offs for the Aldyl A and Aldyl HD pipe would cease in 2013 and 2020, respectively (*Id.*).

Although RUCO agrees that Southwest Gas is entitled to seek modification of the prior write-off requirements, RUCO disagrees with the Company's proposal to retroactively modify the write-off schedule starting in 2000. RUCO argues that Southwest Gas is required to comply with the requirements of Decision No. 58693 until such time as a subsequent Commission Order is issued modifying those requirements (*Id.* at 7-8). Ms. Diaz Cortez agreed that the Company's modified pipe replacement schedule, based on a 40-year life, should be permitted on a going-forward basis, but opposes the retroactive treatment proposed by the Company (*Id.*). Based on its position, RUCO recalculated the write-offs required by Decision No. 58693 and determined that the Company's proposed rate base should be reduced by $1,982,686.

Southwest Gas contends that RUCO misinterpreted the data provided by the Company with respect to pipe replacement amounts. The Company cites to Exhibit A-47, a data request response provided to RUCO that shows the amount of Aldyl A, 1960s steel, and ABS pipe replaced between 2000 and 2004. The Company claims the data request response indicates the costs provided for pipe replacement are 'not necessarily for pipe replaced due to defective material or faulty installation practices'(*Id.*). However, the data request cited by Southwest Gas does not identify which costs are related to the prior Order's requirements. Company witness Robert Mashas testified that the Company disagrees with RUCO's recommendation because 1960s vintage steel pipe was never considered a defective material and was only included as part of the Settlement Agreement because it lacked cathodic protection, which has been installed on all of the Company's steel pipe since 1998 (Ex. A-33, at 16-17).

Contrary to the Company's assertions, neither the Settlement Agreement nor the Order adopting it mention cathodic protection for ***254** 1960s pipe as a distinguishing characteristic that would permit treatment that is different from the other types of pipe that were considered defective and required specific regulatory treatment. Rather, both the Settlement and the Order specifically state that 'In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, Aldyl HD, steel installed in the 1960's, and ABS pipe related to defective materials and/or installation' (Decision No. 58693, at 3).

**6 Mr. Mashas also claims that the effective date of the new write-off should be January 1, 2000, the day after the end of the test year in the Company's last rate case. He contends that this retroactive application of the write-off percentages more accurately reflects the determination of the remedial portion of eligible pipe replacement expenditures (*Id.*). Mr. Mashas stated that the Commission has the authority to make the proposed adjustment retroactive to 2000, and that even RUCO agrees that the Commission has such authority.

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Although we may have the legal authority to make the retroactive adjustment proposed by Southwest Gas, we are not inclined to exercise such authority if it is not in accordance with a valid binding Commission Order which adopted a Settlement Agreement to which Southwest Gas was a signatory party. The Company may not unilaterally alter the terms of a Settlement Agreement and Commission Order simply because it has an understanding of the terms of the agreement that may differ from the belief of another party. Rather, the Company could seek an amendment to the requirements of the prior Order if it believed the terms are no longer applicable, which it has properly done in this docket. However, we agree with RUCO that Southwest Gas must continue to comply with the requirements of the prior Order until such time as those requirements are modified by the Commission. Therefore, based on the weight of the evidence, and in accordance with the directives set forth in Decision No. 58693, we adopt RUCO's position on this issue and will reduce the Company's proposed rate base accordingly.

Summary of Rate Base Adjustments

[6] Based on the foregoing discussion, we adopt an adjusted OCRB of $922,944,881 and a Fair Value Rate Base ('FVRB') of $1,169,584,038.

	Commission Approved
6p	
ORIGINAL COST:	
6p	
Gas Plant in Service - Staff	$1,682,879,492
Less: Accumulated Depreciation	593,408,170
	1,089,471,322
Net Plant in Service	
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076
6p	
Additions:	
Working Capital	881,148
	922,944,881
Total OCRB	
6p	
RCND RATE BASE:	
6p	

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Gas Plant in Service - Staff	$2,439,429,196
Less: Accumulated Depreciation	856,679,561
Net Plant in Service	1,582,749,635
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076
6p	
Additions:	
Working Capital	881,148
Total RCND	1,416,223,194
6p	
FAIR VALUE RATE BASE:	
6p	
Gas Plant in Service - Staff	$2,061,154,344
Less: Accumulated Depreciation	725,043,866
Net Plant in Service	1,336,110,479
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,691,328
6p	
Additions:	
Working Capital	881,148
Total FVRB	1,169,584,038

**255 Operating Income Issues*

**7 In the test year, the Company's adjusted operating revenues were $322,865,978. In its Rebuttal Schedules, Southwest Gas reported adjusted test year operating ex-

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penses of $276,090,356, and test year net operating income of $46,775,622. As reported in its Surrebuttal Schedules, Staff's proposed adjusted test year operating expenses are $276,221,704, resulting in test year operating income of $46,644,274. RUCO's Surrebuttal Schedules show proposed adjusted test year total operating expenses of $272,654,482, yielding test year operating income of $50,211,496. The disputed expense adjustments are discussed below.

Sales and Marketing Wages for 37 Employees

[7, 8] RUCO witness Rodney Moore proposed disallowance of salaries and wages for 37 Southwest Gas employees who he claimed were engaged in sales, marketing and promotional activities. He claimed that ratepayers should not be required to fund the cost of such activities and he proposed removal of almost $3 million in salaries from the Company's test year expenses (RUCO Ex. 5, at 15-16). In his Surrebuttal testimony, Mr. Moore modified his recommendation to exclude the entirety of the 37 employees' wages, stating that 'RUCO would be willing to explore revisiting its position if a fair and reasonable quantification of the time/costs devoted solely to Customer complaint resolution and Regulatory affairs could be substantiated by the Company' (RUCO Ex. 6, at 18).

In her Rebuttal testimony, Company witness Christina Palacios disputed RUCO's analysis and stated that the Company had previously removed almost $600,000 in promotional and marketing expenses, consistent with prior Commission Decisions. Ms. Palacios testified that the employees' wages that RUCO seeks to disallow are responsible for interacting with individual customers and developers seeking information regarding extension of gas service, as well as maintaining oversight until service is extended to a requesting property (Ex. A-5, at 2-6). Ms. Palacios asserted that the job duties of the employees in question include: advising customers on gas products and availability; coordinating new business processes; working with customers to determine technical needs and specifications; investigating and settling customer complaints; ensuring satisfactory customer service; participating in customer business meetings as consultants/advisors; establishing programs to educate customers; interpreting and applying tariffs to main/service extensions; ensuring adequate and timely coordination of services; negotiating contracts and special agreements; preparing studies and analyses; making presentations to trade allies or potential customers; and staying up to date on government regulations and technology changes within the industry (*Id.* at 4). Southwest Gas cites to Decision No. 64172 wherein the Commission denied RUCO's proposal to remove half of the costs associated with Southwest Gas' sales and marketing employees because 'these employees are necessary for processing a request for service ' (Decision No. 64172, at 10-11). The Company also cites to a decision by the United States Supreme Court in *West Ohio Gas Co. v. Public Utilities Com'n of Ohio*, 294 U.S. 63, 72 (1935), which held that '[w]ithin the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes ....'

**8 We agree with RUCO that a portion of the salaries of employees associated with sales, marketing, and promotional activities should be excluded from allowable test year expenses in this proceeding. It appears that the majority of these employees' time is dedicated to duties that enhance service to customers and potential customers, thereby providing benefits to both shareholders and ratepayers. However, by the Company's admission, a certain amount of these same employees' time is devoted to purely marketing or promotional activities that the Commission has previously found are expenses that should not be borne by ratepayers. For example, Ms. Palacios provided an estimate at the hearing that the employees in question devoted approximately 90 percent of their *256 time to non-marketing duties, as described above, and approximately 10 percent to marketing activities (Tr. 109-110). In addition, Company witness Aldridge stated that approximately 17 percent of those same employees' compensation was obtained from the Company's Sales Incentive Plan (Tr. 573-574). Despite the admission by Company witnesses that at least some portion of these employees' time is devoted to sales and marketing activities, no attempt was made to allocate a portion of their wages out of test year ex-

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penses. Based on the best information in the record, we believe it is reasonable to perform such an allocation and we will therefore disallow 10 percent of the 37 employees' wages from test year expenses (*i.e.*, $289,243). In addition, we expect Southwest Gas in its next rate case to provide a detailed explanation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

Labor Annualization and 2005 Wage Increases

[9] In this proceeding, Southwest Gas has included in proposed test year expenses an annualization of wage increases that were given to employees in 2004, as well as wage increases granted in 2005 after the end of the test year. However, the Company included only wage increases for employees who were employed as of the end of the test year to avoid a mismatch (Ex. A-31, at 3-5; Tr. 543-545).

Although RUCO accepts the 2004 wage increase, it disputes the inclusion of the post-test year wage increase because it believes inclusion of the 2005 increase constitutes a double counting of such expenses (RUCO Ex. 6, at 11; Tr. 929-930).

Staff witness Jim Dorf testified that Staff has accepted the reasonableness of including both the 2004 and 2005 wage increases because the costs are known and measurable (Tr. 1085).

We agree with Staff that the 2005 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses.

American Gas Association Dues

****9 [10, 11]** The American Gas Association ('AGA') is a national trade association for natural gas distribution and transmission companies. During 2004, Southwest Gas paid dues to the AGA (Arizona portion) of $211,934 (RUCO Ex. 5, RLM-9). The AGA provides services to its members in the following categories: Public Affairs; Communications; Corporate Affairs and International; General Counsel and Corporate Secretary; Regulatory Affairs; Marketing Development; Operating & Engineering Services; Policy & Analysis; Industry Finance & Administrative Programs; and General & Administrative Expense (Ex. A-30, RLA-3).

Although Southwest Gas claims that it has removed the amount of the dues that are attributable to the AGA's Marketing and Lobbying functions (1.54 percent and 2.10 percent, respectively), RUCO seeks an additional 39.09 percent disallowance ($75,385) for the Public Affairs and Communications functions performed by the AGA (RUCO Ex. 5, RLM-9). According to RUCO witness Moore, the Communications category of AGA operations promotes the use of gas over other fuels, while the Public Affairs category provides members with information on legislative and regulatory developments, provides testimony, comments, and filings regarding legislative and regulatory activities, and lobbies on behalf of the industry (*Id.* at 21-22).

Southwest Gas witness Aldridge countered that the Communications and Public Affairs categories are appropriate AGA functions that should be recovered in test year expenses because the Company removed the amounts specifically associated with marketing and lobbying. Ms. Aldridge testified that the Communications function of the AGA includes developing informational materials for member companies and consumers and coordinating all ***257** media activity (Tr. 550). With respect to the Public Affairs function, the AGA described its activities as follows: 'The [AGA] monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and regulatory trends. In 2002 its major federal, legislative and regulatory efforts were pipeline safety legislation and regulation, Federal funding for Low Income Home Energy Assistance Program (LIHEAP), federal funding for research, and national energy policy legislation.' (Ex. A-30, RLA-3).

We believe that the Company has demonstrated suffi-

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ciently that, having removed the portion of its AGA dues directly attributable to marketing and lobbying, the remainder of the AGA dues should be recoverable as legitimate test year expenses. Although the descriptions of AGA activities provided by the Company are somewhat nebulous, we find that Southwest Gas has met its burden of showing that the functions for which RUCO seeks exclusion have a benefit to the Company and its customers and should be allowed. However, in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers.

**10 *Transmission Integrity Management Program Expenses*

[12, 13] The federal Pipeline Safety Improvement Act of 2002 directed the Office of Pipeline Safety and the Research and Special Programs Administration divisions of the U.S. Department of Transportation to enact regulations creating standards for transmission pipeline risk analysis and adopting a pipeline integrity management program (Ex. A-32, at 19-21). In Arizona, Southwest Gas has identified approximately 335 miles of transmission facilities located in high consequence areas that are subject to the federal legislation (Ex. S-3, at 6-7). The Company's application in this docket includes an expense adjustment to recover costs associated with compliance with this legislation, which Southwest Gas calls its Transmission Integrity Management Program ('TRIMP '). The Company seeks to recover costs incurred prior to the effective date of the rates in this proceeding, as well as a representative level of ongoing costs that it expects to incur due to ongoing TRIMP activities (*Id.*). Although the Company initially sought to recover a higher level of TRIMP expenses, it subsequently agreed to RUCO's recommendation to amortize 2004 and 2005 TRIMP costs over 7 years ($138,365 annually), with an additional test year allowance of $603,677 annually (RUCO Ex. 3, MDC-5).

Staff witness Dorf testified that although Staff encourages Southwest Gas to comply fully with the new pipeline safety regulations, Staff is concerned with the volatility of the Company's estimated compliance costs, as exemplified by a comparison of the Company's original estimate of more than $12 million through 2009 compared to its revised estimate of just over $3 million (Ex. S-4, at 5). Due to this fluctuation in the estimated ongoing compliance costs, as well as Staff's belief that the expenses should be borne jointly by shareholders and ratepayers, Mr. Dorf recommended establishment of a surcharge mechanism that would allow recovery through rates of half of the baseline direct assessment, direct examination, and maintenance and repair TRIMP-related costs (but not capital replacements). Staff proposes that the surcharge be labeled on customer bills as 'DOT Pipeline Safety Surcharge.' Staff's proposed surcharge would have annual adjustments after the first and second year, and would terminate at the end of the third year (Ex. S-3, at 11-14). Mr. Dorf explained that Staff's rationale for its recommendation is based on the following factors: 1) the Pipeline Safety Act of 2002 has significantly modified pipeline safety regulations; 2) the estimated costs of complying with the new regulations are significant; 3) initial assessments must be performed in a compressed time period; 4) current rates do not provide for recovery of these incremental costs; and 5) the costs are estimated at this time and are therefore inappropriate for inclusion in base rates (*Id.* at 12).

***258** We agree with the reasoning expressed by Staff witness Dorf that TRIMP costs should be borne equally by shareholders and ratepayers, and a surcharge mechanism is the appropriate means of recovery. As Mr. Dorf stated at the hearing, recovery of TRIMP expenses through a surcharge would mitigate potential volatility in the program's costs especially given the long projection period for completing the first cycle of TRIMP costs (Tr. 1082). With respect to the split of TRIMP costs, we also agree with Staff that because the pipeline safety program benefits both shareholders and ratepayers, the TRIMP expenses should be shared equally. We will therefore adopt Staff's recommendation for treatment of TRIMP costs.

Sarbanes-Oxley Compliance Expenses

11 **[14] Section 404 of the Sarbanes-Oxley Act of 2002 ('SOX') requires the establishment of an internal

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control structure and certain procedures for financial reporting, including a requirement that the company's annual report contain an internal control report (Ex. A-29, at 21-22). This legislation created the Public Company Accounting Oversight Board, and requires that publicly traded companies' external auditors attest to and report on management's assessment of the effectiveness of their internal controls and procedures. Companies were required to be in compliance with SOX by December 31, 2004 (Ex. S-3, at 15).

Southwest Gas seeks an adjustment to recover expenses related to the initial assessment and review of the Company's internal controls and additional post-test year expenses that it claims are necessary to fully implement SOX requirements, as well as estimated incremental and recurring compliance costs related to audit fees (Ex. A-30, at 9-13). Subsequent to filing its application, the Company updated its estimated compliance costs to reflect actual expenses, and Ms. Aldridge testified that those costs are reasonable in light of the Company's use of internal labor, including exempt employee labor for which overtime pay was not required (*Id.*).

Staff recommends an equal sharing of ongoing SOX compliance costs between ratepayers and shareholders based on its claim that the improved internal controls required by SOX provide a benefit to both groups. Staff witness Dorf stated that the SOX requirements protect ratepayers with improved compliance and benefits shareholders by protecting them from management impropriety (Staff Ex. 3, at 17). Mr. Dorf also testified that Staff recommends a 25 percent reduction of initial audit costs based on published reports by the American Institute of Certified Public Accountants that original estimates were overstated, and Staff recommends disallowance of the Company's proposed recovery of non-recurring implementation costs (*Id.*;Tr. 1085-1087).

Although it is important for Southwest Gas to comply fully with federally mandated audit and reporting requirements, we believe Staff's recommendation more accurately reflects the actual SOX compliance costs that will be incurred by the Company for the period that the rates set in this proceeding are in effect. As Mr. Dorf points out in his testimony, Staff's recommendation is based on numerous published articles that indicate there will be significant reductions to many companies' first year implementation and audit costs. Mr. Dorf cited to a white paper published by Enterprise Financial Consulting, LLP, which suggests numerous ways to reduce SOX costs in future years, and indicates that use of a compliance software application alone could save a minimum of 30 percent of the initial compliance costs (Ex. S-4, at 6).

We also agree with Staff's equal sharing of ongoing SOX compliance costs given the clear benefit that shareholders will receive in addition to ratepayer benefits. If anything, shareholders are likely to be greater beneficiaries of the SOX legislation because compliance with the new law will provide additional assurance that companies' financial statements have a higher degree of reliability. Indeed, ratepayers are at best only secondary beneficiaries of the SOX compliance procedures. We will therefore adopt Staff's position on this issue.

Management Incentive Program

**12 [15] Southwest Gas provides compensation*259 in addition to base salaries to certain eligible management employees through its Management Incentive Program ('MIP') based on achievement of the following five factors: 1) an improved customer-to-employee ratio when compared to the prior year; 2) a comparison of the Company's customer-to-employee ratio to its peer utilities; 3) the results of customer satisfaction surveys; 4) the achievement of a three-year return on equity ('ROE') target; and 5) a comparison of the Company's ROE to its peer utilities (Ex. A-33, at 7). Company witness Mashas claims that these five factors were designed to align customer and shareholder interests (*Id.*). Southwest Gas contends that achieving these goals increases productivity and helps the Company retain quality employees by deferring 60 percent of the MIP payout for three years (*Id.* at 6-11).

RUCO proposes to reduce MIP expenses by 67 percent to recognize that shareholders receive the majority of benefits through achievement of the MIP performance targets, especially between rate cases. Ms. Diaz Cortez

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testified that amounts awarded under the MIP could be viewed as bonuses because the eligible individuals also receive wage and salary increases. She also stated that the annual amount of MIP compensation is not known and measurable because the payouts depend on reaching the performance goals (RUCO Ex. 3, at 20-23).

Staff also recommends reducing MIP expenses, but proposes an equal sharing between shareholders and ratepayers. Staff witness Dorf stated that shareholders and ratepayers stand to benefit from the performance goals, but added that there is no assurance that the award levels achieved during the test year will be repeated in future years (Ex. S-4, at 9-10).

Southwest Gas responds that MIP payouts should be considered part of the employees' overall compensation package and no party in the case has suggested that the employees' total pay is unreasonable, and that the Company is penalized by the Staff and RUCO proposals by putting part of its management's compensation at risk. According to Southwest Gas, if the Company put these amounts in the employees' base salary, Staff and RUCO would not claim that there should be a disallowance.

In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

Supplemental Executive Retirement Plan

13 **[16, 17] Southwest Gas offers a Supplemental Executive Retirement Plan ('SERP') to the Company's officers. Company witness Mashas testified that the SERP is necessary 'to ensure that the retirement and deferred compensation portions of [the officers'] total compensation are on parity with all other employees of Southwest whose retirement distribution is not impacted by certain IRS regulations' (Ex. A-33, at 3). Mr. Mashas claims that recovery of the SERP costs is reasonable due to restrictions on these employees' basic retirement plan ('BRP'), exclusion of deferred compensation from the BRP calculation, and the need to ensure attraction and retention of qualified employees. Mr. Mashas explained that IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service (*Id.* at 5-6). In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that 'maximum**260** contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees' (*Id.* at 4-5).

RUCO witness Moore proposed a reduction in test year expenses of approximately $2.7 million associated with the SERP. Mr. Moore stated the cost of these supplemental retirement benefits for select executives is not a necessary cost of providing gas service to customers because the Company's officers are already fairly compensated with a wide array of benefits, including a retirement plan. Mr. Moore cited to the Company's most recent rate case before the Nevada Public Utilities Commission [FN3] where Southwest Gas' SERP expenses were excluded from the Company's operating expenses (RUCO Ex. 5, at 28-29).

We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employ-

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ees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Miscellaneous Expenses

14 **[18, 19] Through her Direct testimony, Company witness Aldridge indicated that the application included an adjustment to remove certain miscellaneous expenses for items such as gym memberships, donations and meals (Ex. A-29, at 23).

Based on his review of data requests, RUCO witness Moore proposed an additional adjustment to remove from test year expenses 'payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service' (RUCO Ex. 5, at 25).

In her Rebuttal testimony, Ms. Aldridge stated that RUCO had failed to justify the exclusion of the various miscellaneous expenses identified by Mr. Moore. Ms. Aldridge claimed that the vast majority of the expenditures are reasonable, recurring, and necessary business expenses and should remain in cost of service. However, after additional review, Ms. Aldridge accepted exclusion of a portion of RUCO's proposed disallowance ($62,165 Arizona jurisdictional), but further testified that accepting RUCO's recommendation would result in exclusion of expenses related to moving expenses for a transferred employee; safety awards and costs related to the Company's Operations Center; alcohol and drug testing; and continuing professional education (Ex. A-30, at 15-16).

In his Surrebuttal testimony, Mr. Moore indicated that there were additional expenses the Company had not removed that RUCO believes should not be recoverable through rates. Examples of expenses that Mr. Moore claims remain in the Company's miscellaneous expenses include: liquor, coffee, water, ice, sodas, smoothies, bagels, donuts, subs, trophies, flowers, gift certificates, photographs, charitable/community service club donations, travel reduction programs, shareholder meetings, recognition events, sports events, club memberships, art work, and barbecues and accessories (RUCO Ex. 6, at 20-21). Mr. Moore stated that RUCO would agree to reduce its proposed disallowance by approximately 20 percent, from $346,299 to $277,039, 'to avoid the tedious litigation of line-by-line examination of the 40 pages of workpapers'(*Id.* at 21).

In her Rejoinder testimony, Ms. Aldridge claimed that specific items identified by Mr. Moore (*i.e.*, liquor, club donations, sports *261 events, club memberships, barbecues) were removed by the Company as part of the $62,165 adjustment described above (Ex. A-31, at 14-15). She indicated that certain meal costs and expenses related to employee appreciation and charitable events were not removed because she believes such expenses are reasonable business expenses. Ms. Aldridge also criticized RUCO's analysis of the workpapers provided through data requests as lacking sufficient detail which was 'not even enough for *the Company* to determine whether a transaction should remain in cost of service' (emphasis original) (*Id.* at 16). She therefore concluded that 'RUCO has simply presented insufficient evidence to support their proposed disallowance'(*Id.*). On cross-examination, Ms. Aldridge maintained that she had removed expenses related to barbecues, Jeep tours, and balloon rides as part of the $62,165 adjustment, but that other expenses for items such as awards for meter reading accuracy, safe driving awards, shareholder meetings, photographs, sympathy cards and flowers are necessary business expenses that should be recovered through rates (Tr. 353-358, 583-587). She admitted that the exclusion of $62,165 of expenses (for barbecues, Jeep tours etc.) were removed only after RUCO raised the issue through its testimony (Tr. 583).

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**15 Although we appreciate Ms. Aldridge's attempt to exclude expenses that are clearly inappropriate for recovery from ratepayers, we do not believe that the Company has met its burden of proving the reasonableness of all of the miscellaneous expenses for which it seeks recovery. It is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions. Given the state of the record, it is unclear precisely which additional miscellaneous expenses should be excluded from cost of service, but we believe that at least a portion of the items that the Company believes are reasonable business expenses should be disallowed (*e.g.*, shareholder meeting expenses). Because the Company failed to sustain its burden of proof on this issue, but also recognizing that many of these miscellaneous expenses may be legitimate and reasonable business expenses, we will disallow half of RUCO's original proposed disallowance ($346,299 X 50% = $173,150 disallowance).

Southwest Gas Legal Arguments

[20-22] Throughout its legal Briefs, Southwest Gas repeatedly cites the case of *Anaheim, Riverside, Banning, Colton, and Azusa, California v. Federal Energy Regulatory Commission*, 669 F.2d 799, 809 (U.S. App. D.C. 1981), to support its assertion that Staff's recommendations must fail because Staff failed to present sufficient evidence to raise a serious doubt as to the prudence of the Company's proposal. As Staff points out in its Reply Brief, the *Anaheim* case was based on the Federal Power Act which, pursuant to 16 U.S.C. § 824d(e), imposes on the utility company the 'burden of proof to show that the increased rate of charge is just and reasonable.' The *Anaheim* case, while not controlling precedent, also stands for the proposition that once a party challenges the propriety of a particular aspect of the company's application with some credible evidence, it is incumbent upon the utility to demonstrate the reasonableness of its proposals. The evidence presented through sworn testimony and other exhibits has been carefully weighed and a just and reasonable result achieved based on consideration of the competing evidence and arguments. As established by the Arizona Constitution and relevant case law, this Commission has broad discretion in setting just and reasonable rates and we believe our findings herein achieve that goal despite the Company's disagreement.

Southwest Gas also repeatedly cites *West Ohio Gas v. Public Utilities Commission of Ohio*, 294 U.S. 63 (1935), to support its contention that specific expense items, including advertising and promotional costs, must be presumed reasonable. While the *West Ohio Gas* case indicates that 'good faith' should be presumed on the part of a company's managers *262 with respect to the prudence of expenditures, we disagree with the position advocated by Southwest Gas that our consideration of the reasonableness of any particular expense may not include recognition of the relative benefits that may be derived from such costs. The test of reasonableness is based on a host of considerations presented in the record and may not be reduced to a simple pass through of costs claimed by the Company in order to pass legal muster. The Commission's ratemaking authority allows precisely the type of analysis that has been conducted with respect to these expense items and is consistent with case law interpreting that authority.*Net Operating Income*

**16 [23, 24] Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of $275,031,605, which based on test year revenues of $322,865,978, results in test year adjusted operating income of $47,834,373, a 6.63 percent rate of return on FVRB.

COST OF CAPITAL

As amended at the hearing, Southwest Gas recommends that the Commission determine the Company's cost of common equity to be 11.42 percent if its proposed conservation margin tracker ('CMT') is not adopted and 11.17 percent with adoption of the CMT (see discussion of CMT below). The Company's weighted cost of capital recommendation is 9.24 percent without the CMT and 9.13 percent with the CMT (Tr. 783-784; Ex. A-

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54). Staff recommends a cost of common equity rate of 9.50 percent with an overall weighted average cost of capital determination of 8.40 percent (Ex. S-1, SGH-1, Sched. 11). RUCO proposes adoption of a cost of common equity of 10.15 percent and a weighted average cost of capital of 8.64 percent (RUCO Ex. 1, WAR-1).

Capital Structure

[25] During the test year, Southwest Gas had average actual capital structure consisting of 34.5 percent common equity, 5.3 percent preferred stock, and 60.2 percent long-term debt (Ex. A-38, TKW-1). The Company, Staff, and RUCO agree that the Commission should employ a hypothetical capital structure for purposes of setting rates in this proceeding. However, Staff disagrees with the Company and RUCO as to the composition of the hypothetical structure.

Southwest Gas proposes adoption of a hypothetical capital structure of 42 percent common equity, 5 percent preferred equity, and 53 percent long-term debt (Ex. A-38, at 8-33). According to Company witness Theodore Wood, Southwest Gas has improved its actual common equity ratio from 31.1 percent in 1995 to 37.0 percent as of June 30, 2005, despite the financial challenges facing the Company from a combination of rapid customer growth and inability to earn its authorized rate of return (Ex. A-40, at 7). Mr. Wood stated that the Company's requested 42 percent hypothetical structure is consistent with past Commission practice to set the equity ratio above the Company's actual capital structure but below the average of similar risk natural gas distribution companies (*Id.* at 11). Mr. Wood criticizes Staff's proposed 40 percent capital structure and cites to Southwest Gas' issuance of approximately 15.8 million shares of common stock between 1994 and 2004, netting $313.7 million in proceeds, as well as the recent $60 million Equity Shelf Program, as examples of the Company's dedication to improve its equity ratio despite financial hurdles (*Id.* at 16; Ex. A-39, at 20-21). Mr. Wood was also critical of Staff's recommendation to require a formal recapitalization plan because of the dilution effect on existing shares and the potential negative impact on the Company's stock price. According to Mr. Wood, such a requirement would be detrimental to the integrity of existing capital and could hinder the Company's ability to maximize proceeds from subsequent stock offerings (*Id.* at 21-22).

****17** Although, as discussed below, RUCO disagrees with Southwest Gas' overall cost of capital recommendation, it agrees with the Company's***263** hypothetical capital structure proposal. RUCO witness William Rigsby stated that he adopted the Company's hypothetical structure in his analysis because Southwest Gas is close to the average debt and equity percentages in his sample group of local distribution companies ('LDCs'). The capital structures for his sample group averaged 51.2 percent long-term debt, 0.3 percent preferred equity, and 48.5 percent common equity (RUCO Ex. 1, at 44-45). Thus, when Southwest Gas' preferred and common equity are combined under RUCO's proposed hypothetical structure, a 47 percent total equity ratio is achieved for purposes of analyzing the Company's cost of capital.

Staff recommends that the Commission adopt a 40 percent hypothetical structure, with 5 percent preferred stock and 55 percent debt, for purposes of determining Southwest Gas' overall cost of capital in this proceeding. Staff witness Stephen Hill testified that the equity ratio of Southwest Gas has been consistently low for more than a decade and that ratepayers should not be required to, in effect, subsidize the Company's equity return to the extent requested by Southwest Gas (Ex. S-1, at 20-27). Mr. Hill stated that Staff's recommended 40 percent equity ratio provides an appropriate balance between financial safety and economy for Southwest Gas and is consistent with the hypothetical structure adopted in the Company's last rate case (*Id.*). Mr. Hill also recommends that the Commission should require Southwest Gas to submit a re-capitalization plan for how the Company can reach an actual 40 percent equity goal prior to its next rate proceeding. Mr. Hill further proposes that if the Company elects not to increase equity capital to at least 40 percent, the Commission should set rates in the next case using the actual capital structure at that time (*Id.* at 26).

Although it did not present a specific cost of capital recommendation, AUIA criticized Staff's proposal to re-

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quire Southwest Gas to adopt a recapitalization plan to increase its equity ratio to at least 40 percent by the Company's next rate case. AUIA argues that the cause of the Company's debt-heavy capital structure is its inability to earn its authorized rate of return over a number of years, which it claims is at least as damaging to shareholders as ratepayers. AUIA witness Walter Meek testified that shareholders would support a plan to achieve a 40 percent equity ratio if the Commission would adopt a rate design that would enable Southwest Gas to actually earn its authorized rate of return (AUIA Ex. 2, at 8).

We agree with Staff that use of a 40 percent equity ratio is appropriate in this proceeding. The 40 percent ratio is more than 5 points higher than the ratio in existence at the end of the test year and 3 points higher than the Company's equity at the end of June 2005. This hypothetical capital structure is consistent with our Order in the Company's last rate case (Decision No. 64172, at 17). Although Southwest Gas has made some progress over the past decade to improve its equity position relative to debt, our continuing need to employ an inflated equity ratio for setting rates in case after case highlights the need to encourage even greater efforts to increase the equity ratio. Ultimately, however, the level of equity lies within the control of the Company's management and not with ratepayers who have been asked to shoulder the burden of rates set based on a hypothetical structure that does not actually exist.

**18 As Staff witness Hill pointed out, ratepayers have for many years been burdened with an authorized return set using a hypothetical capital structure far greater than the Company's actual equity ratio. At some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure. Therefore, we believe it is also appropriate to adopt Staff's recommendation to require Southwest to submit a re-capitalization plan explaining how it intends to achieve a 40 percent equity prior to the Company's next rate case. We do not believe it is necessary, at this time, to determine whether failure to reach the 40 percent goal would result in use of the Company's actual capital structure in its next rate case. However, the possibility of such a determination in the next rate case will depend on the Company's efforts to make progress on this *264 issue based on the plan it develops and implements pursuant to this Order.

Cost of Common Equity

[26] Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimation that is both art and science. As evidenced by the competing methodologies employed by the three cost of capital witnesses in this case, there is no clear-cut answer as to which formula should be used for reaching the appropriate outcome. Rather, the three expert witnesses, Messrs. Hanley, Hill, and Rigsby, each rely on various analyses for their recommendations.

Southwest Gas

Southwest Gas' expert witness, Frank Hanley, based his common equity cost recommendation of 11.42 percent (or 11.17 percent with the CMT) on the results of his common equity models, namely, the Discounted Cash Flow ('DCF'), Risk Premium Model ('RPM'), Capital Asset Pricing Model ('CAPM'), and Comparable Earnings Model ('CEM'). According to Mr. Hanley, use of these models is consistent with the Efficient Market Hypothesis ('EMH'), which is based on the premise that investors are aware of all relevant publicly available information in making their investment decisions (Ex. A-35, at 20-24). Mr. Hanley stated that, absent evidence to the contrary, it must be assumed that investors are aware of all of the models he used in his analysis and that those investors take the models into account in making their decisions (*Id.*).

In his analysis, Mr. Hanley developed two proxy groups of comparable gas distribution companies. Based on an historical comparison of financial data for the proxy groups and Southwest Gas, Mr. Hanley found that Southwest Gas has earned returns well below those of the proxy groups (Tr. 680-681). According to Mr. Hanley, during the period of 1997 through 2003, Southwest Gas achieved an average return on actual book common

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equity of 6.74 percent in Arizona, compared to the 11.62 percent and 12.11 percent average return on equity ('ROE ') realized by the proxy groups (Ex. A-35, FJH-1).

**19 The Company argues that there is an even greater disparity with the proxy group ROEs if Southwest Gas' greater level of business risk is taken into account, as evidenced by the Standard & Poor business profile of 3.0 for Southwest Gas compared to the proxy group average profiles of 1.8 and 2.0 (Ex. A-35, at 13-14, FJH-11). The Company also claims its ROE request is reasonable compared to other litigated cases for LDCs across the country the past several years, where the average ROE granted was 10.91 percent, for companies with a common equity ratio of 47.5 percent (Ex. A-36, at 41, FJH-24). The Company argues that these comparisons support the need for a higher ROE because Southwest Gas is more risky, from both a business and financial risk perspective.

Southwest Gas contends that Staff's recommended ROE understates significantly a reasonable return for the Company based on *Value Line* forecasts for other LDCs. Mr. Hanley cited to a *Value Line* survey from June 17, 2005, which reported an expected 12.5 percent ROE for such companies relative to a 45.5 percent common equity ratio (Ex. A-37, at 16). Mr. Hanley criticized Staff's reliance on the DCF method for determining ROE based on his claim that the DCF tends to understate the common equity cost rates when market values exceed book values and when such market-based investors' required rates of return are applied to lower book values (*Id.* at 7).

The Company also cites to the *Hope* and *Bluefield* cases [FN4] , as well as Article 15, § 3 of the Arizona Constitution and *Residential Utility Consumer Office v. Arizona Corporation Com'n*, 199 Ariz. 588 (2001), for the proposition that the Commission must consider Southwest Gas' greater risk relative to other LDCs when determining an appropriate common equity cost rate.

RUCO

RUCO contends that its proposed 10.15 *265 percent cost of common equity is appropriate given the Company's actual capital structure, the current environment of relatively low inflation and interest rates, and the Company's relatively higher financial risk compared to other similar LDCs (RUCO Ex. 1, at 43-45). RUCO witness Rigsby employed both a DCF analysis and CAPM to reach his recommendation. His DCF analysis yielded an 8.91 percent COE result, while the CAPM resulted in a range of 8.82 to 10.39 percent (*Id.* at 27). In reaching his 10.15 recommendation, Mr. Rigsby rounded up (to 10.40) the upper end of his CAPM results, and then reduced that result by 25 basis points to achieve RUCO's proposed 10.15 cost of common equity (*Id.*).

Mr. Rigsby acknowledged that his proposal is 124 basis points higher than the 8.91 percent DCF result, but contends Southwest Gas' heavily leveraged position and higher level of financial risk compared to his proxy LDCs warrants a recommendation at the higher end of his results. He also states that his recommendation is close to the 10.50 percent return on common equity adopted by the Nevada Public Utilities Commission in Southwest Gash most recent rate proceeding (Docket No. 04-3011). Mr. Rigsby indicated that his decision to lower the COE recommendation by 25 basis points from the CAPM upper end was based on RUCO's recommendation to adopt a rate design that mitigates income volatility to Southwest Gas by shifting more of the revenue recovery from the Company's commodity charge to its fixed monthly charge, in lieu of adopting the Company's proposed CMT (*Id.* at 28). On the other end of the spectrum, his recommendation of 124 basis points above the DCF result reflects concern over the Company's inability to achieve higher levels of shareholder equity and the *Value Line* comparison to other proxy LDCs compared to Southwest Gas (*Id.* at 29).

Staff

**20 In determining Staff's cost of common equity recommendation in this proceeding, Staff witness Stephen Hill conducted a DCF analysis which resulted in a cost of common equity estimate of 9.20 percent. Mr. Hill

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stated that, in order to support and temper his DCF results, he used three additional econometric models to estimate the cost of equity capital for a group of firms similar in investment risk to Southwest Gas. The three additional methods used by Mr. Hill are: 1) CAPM; 2) the Modified Earnings-Price Ratio ('MEPR'); and 3) the Market-to-Book Ratio ('MTB'). The sample proxy companies used for these models are the same as those employed by Mr. Hill for his DCF analysis (Ex. S-1, at 36-37). Mr. Hill's CAPM analysis resulted in a cost of capital for the proxy companies ranging from 7.71 to 9.38 percent (*Id.*, Sched. 7). For the MEPR model, the cost of equity capital ranged from 8.68 to 8.78 percent (*Id.*, Sched. 9). Finally, Mr. Hill's MTB analysis resulted in cost of equity capital ranging from 8.84 to 9.46 percent (*Id.*, Sched. 10).

Although Mr. Hill relied primarily on the 9.20 percent DCF result for determining his cost of equity recommendation, he also averaged the corroborative results (*i.e.*, CAPM, MEPR, and MTB) which produced a range of 8.41 to 9.21 percent, which he noted is almost entirely below the DCF result. As a result, Mr. Hill concluded that the DCF was a conservative (*i.e.*, high) estimate of the Company's estimated cost of equity capital and therefore the DCF result should be considered to be in the upper range of equity capital cost for Southwest Gas. However, due to his expectation of higher short-term interest rates in the near term, Mr. Hill stated that it was appropriate to set a range so that his DCF result is near the middle of a reasonable range. He therefore determined that the best estimate of the cost of equity capital for a company facing similar risks as that group of gas distribution companies ranges from 9.00 to 9.50 percent (*Id.* at 37). Because Southwest Gas' capital structure contains less common equity than the proxy group he used to estimate the cost of equity capital, Mr. Hill concluded that the additional risk faced by Southwest Gas warrants an equity return at the high end of his range, or 9.50 percent (*Id.* at 40).

Conclusion on Cost of Equity

***266 [27-34]** We believe that Staff's recommended cost of equity capital in this proceeding achieves an appropriate result that is supported by the evidence in the record. Staff witness Hill's use of the DCF as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.

As Mr. Hill explained in his testimony, both historical and projected growth rates were calculated for his sample group of gas distribution companies. The companies in Mr. Hill's proxy group possess similar risk characteristics and, based on a sustainable growth rate supported by data published *Value Line* and other financial publications, produced a growth rate estimate of 5.12 percent (Ex. S-1, at 29-34). Although Staff's COE recommendation is based primarily on the DCF analysis, as explained above Mr. Hill also conducted a review of other COE formulas, including CAPM, to corroborate the DCF results.

****21** Mr. Hill also testified that the methods utilized by the Company's witness, which depend heavily on beta (a relative risk measure which is designed to measure investor risk), does not provide an accurate portrayal of actual investment risk (Tr. 877). Staff points out that the Company's witness, Mr. Hanley, excluded 8 of 11 indicated DCF return rates from his proxy group based on his opinion that any result under 9.90 percent did not reflect returns being authorized in other jurisdictions. As Mr. Hill pointed out on the witness stand, if those 8 companies were included in Mr. Hanley's DCF calculation, the result would be approximately 9.2 percent, which is almost identical to Staff's DCF calculation (Tr. 876).

After reviewing the various proposals summarized herein, and as further described in the testimony prepared by the parties' expert witnesses, we believe Staff's cost of equity capital recommendation is an appropriate result for determining the Company's overall cost of capital in this proceeding. Staff's DCF calculation of 9.20 percent, with an upward adjustment of 30 basis points to 9.50 percent, gives recognition to the higher risk faced by Southwest Gas.

We are not persuaded by the Company's legal arguments that adoption of Staff's cost of equity recom-

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mendation would result in a violation of the Commission's authority under the Arizona Constitution, the case law interpreting that authority, or of the *Hope* and *Bluefield* decisions. Article 15, Section 3 of the Arizona Constitution provides in relevant part that the Commission 'shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein.' In determining just and reasonable rates, the Commission has broad discretion subject to the obligation to ascertain the fair value of the utility's property, and establishing rates that 'meet the overall operating costs of the utility and produce a reasonable rate of return.' *Scates, et al. v. Arizona Corp. Com'n*, 118 Ariz. 531, 534, 578 P.2d 612 (Ct. App. 1978). Under the Arizona Constitution, a utility company is entitled to a fair rate of return on the fair value of its properties, 'no more and no less.' *Litchfield Park Service Co. v. Arizona Corp. Com'n*, 178 Ariz. 431, 434, 874 P.2d 988 (Ct. App. 1994), *citing Arizona Corp. Com'n v. Citizens Utilities Co.*, 120 Ariz. 184 (Ct. App. 1978). The oft cited *Hope* and *Bluefield* cases provide that the return determined by the Commission must be equal to an investment with similar risks made at generally the same time, and should be sufficient under efficient management to enable the Company to maintain its credit standing and raise funds needed for the proper discharge of its duties.

For the reasons described above, we believe that adoption of Staff's recommendation for a 9.50 cost of equity capital, and overall 8.40 percent weighted cost of capital comply with these obligations. Staff's expert witness, although primarily relying on the well-established DCF method for calculating his cost of equity capital, also employed two other tests as a check on the reasonableness of his results. He also pointed out that the Company's witness arbitrarily excluded 8 of the 11 companies in his proxy group because they produced DCF *267 results less than 9.90 percent, and thus skewed downward the overall results on his analysis. Moreover, Staff's witness gave recognition to Southwest Gas' highly leveraged capital structure by adding 30 basis points to his DCF results. We therefore believe that adoption of Staff's recommendation results in a just and reasonable return for Southwest Gas based on the record of this proceeding.

**22 We therefore adopt a cost of equity of 9.50 percent, which results in an overall weighted cost of capital of 8.40 percent.

	Percentage	Cost	Avg. Weighted Cost
Common Equity	40.0%	9.50%	3.80%
Preferred Equity	5.00%	8.20%	0.41%
Total Debt	55.0%	7.61%	4.19%
			8.40%

AUTHORIZED INCREASE

Based on our findings herein, we determine that Southwest Gas is entitled to a gross revenue increase of $49,345,636.

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Fair Value Rate Base	$1,169,584,038
Adjusted Operating Income	47,834,373
Required Rate of Return	6.63%
Required Operating Income	77,508,617
Operating Income Deficiency	29,674,244
Gross Revenue Conversion Factor	1.6629
Gross Revenue Increase	49,345,636

RATE DESIGN ISSUES

Conservation Margin Tracker

[35-38] Southwest Gas has proposed in this proceeding a decoupling mechanism that it calls a Conservation Margin Tracker ('CMT') to address the Company's ongoing inability to achieve its authorized rate of return due, at least in part, to declining per customer usage on its system. The Company has proposed that the CMT be imposed only on the residential class (although it does not oppose broader application). Under the CMT, if Southwest Gas does not achieve its authorized 'margin' (*i.e.*, all costs of providing gas less the cost of the gas itself) per customer class, the CMT would track that shortfall and impose a surcharge on customers in that class the following year based on the prior year's revenue shortfall. In effect, the CMT would insulate Southwest Gas from the risk associated with declining gas usage by customers.

The Company claims that the CMT is a reasonable cost recovery mechanism for the following reasons: it would eliminate the Company's financial disincentive associated with promoting Demand Side Management ('DSM') programs; it would not discourage consumers from conserving natural gas because the more a customer conserves the more the customer would save; it would charge customers only the fixed costs of service that the Commission authorized in the rate case; it would protect customers from the Company earning more than its authorized margin per customer during a colder than normal heating season; it would protect the Company from declining residential use per customer; and it would provide the Company with a more consistent revenue stream by reducing its dependency on gas sales to recover the authorized margin per customer, thus having a positive impact on the Company's ratings with credit agencies and reducing borrowing costs needed to fund infrastructure growth (Ex. A-19, at 18-23; Ex. A-20, at 14-22; Ex. A-21, at 5-9). Southwest Gas contends that it is willing to modify the CMT or accept another type of decoupling mechanism to address the declining usage problems that it claims all parties have acknowledged exist.

Staff opposes adoption of the CMT because customers would be charged more for gas that is not used the preceding year. Staff argues that if natural gas is relatively inelastic, as the Company contends, the potential for ongoing conservation would be mitigated and usage levels will stabilize over time, thus minimizing the declining usage that impacts the Company's revenues. However, if the declining usage trend continues, Staff claims that the CMT would result in customers incurring additional charges if their conservation efforts ***268** proved successful, thereby discouraging price signals that could lead to conservation. Staff also opposes the CMT on the basis that it could result in sharp increases for residential customers if the Company fails to recover its authorized margin. Staff argues that implementation of the CMT would provide Southwest Gas a guaranteed rate of return, rather than the opportunity to earn a reasonable return as required by law. Staff asserts that the Company's historical inability to earn its authorized return should be addressed through traditional rate design methodologies, such as gradually moving closer to a more cost-based rate design. Staff points out that the Nevada Commission rejected an almost identical decoupling mechanism proposed by Southwest Gas.

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**23 RUCO also opposes the Company's CMT proposal. Although RUCO agrees that the Commission should modify the existing rate design to allow greater recovery of fixed costs, it claims that the CMT is too extreme a remedy for addressing declining usage. RUCO argues that the approved rate design should not provide the Company with a guaranteed recovery of margin, and would allow recovery from customers who were not even on the system when the shortfall occurred. RUCO further opposes the CMT on the basis that it would be applicable only to residential customers, and because the CMT would have the effect of requiring customers to pay the authorized margin for therms they do not consume (RUCO Ex. 3, at 29). RUCO argues that although the Company declined to propose a rate design that would recover all of the margin through the basic service charge, because it believes such a rate design would be inconsistent with the principle of gradualism, it has proposed the CMT which would have the same extreme effect on residential customers.

SWEEP/NRDC expressed understanding of the dilemma faced by Southwest Gas with respect to decreasing usage and revenues. However, SWEEP/NRDC opposes adoption of the CMT in this proceeding. Its witness, Jeff Schlegel, stated that a full analysis of the benefits and drawbacks of decoupling mechanisms for LDCs warrant consideration in a broader context (SWEEP/NRDC Ex. 1, at 7-8). SWEEP/NRDC suggests that the issue of financial disincentives should be addressed through the DSM policy process, via comments and/or workshops. SWEEP/NRDC contends that consideration of the decoupling issues should address questions such as who bears the risk of weather variations and variations in economic growth from forecasted levels and overall demographic and energy usage trends (*Id.*).

AUIA argues that the financial situation faced by Southwest Gas requires adoption of a decoupling mechanism, such as the CMT, or a significant increase in margin recovery through the fixed monthly charge. AUIA contends that the decoupling concept is not radical or drastic, as Staff and RUCO contend, given the adoption of such a mechanism in at least three other states. AUIA cites the testimony of Company witness Steven Fetter, former Chairman of the Michigan Public Service Commission, in support of the CMT. Mr. Fetter indicated that declining margin recovery from volume sales is a national phenomenon and NARUC has passed a resolution urging its members to consider decoupling mechanisms (Ex. A-7, at 6-8).

Conclusion on CMT

Although we recognize that Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis, we do not believe the proposed CMT should be adopted in this proceeding. The Company has suggested that it is open to other decoupling mechanisms as a solution, and we believe that the issue should be fully explored as part of a broader investigation of usage volatility and margin recovery.

There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers. Further, as RUCO points out, the likely effect of adopting the proposed CMT is that residential customers will be required to pay for gas that they have not used in prior years, a phenomenon*269 that could result in disincentives for such customers to undertake conservation efforts. We are also concerned with the dramatic impact that could be experienced by customers faced with a surcharge for not using 'enough' gas the prior year. The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case.

**24 We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discus-

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sions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

Allocation of Margin Among Customer Classes

[39, 40] As a means of allocating margin costs between the various classes of customers it serves, Southwest Gas presented a cost of service study to support its rate design proposal. Company witness Congdon stated that the Company's allocation of margin methodology is based on this cost of service study, and the proposed allocation would move each class' rate of return closer to cost of service (Ex. A-17, at 22-24). The Company argues that its cost of service study was not challenged by any party and, because its proposed allocation is directly based on the cost of service study, the Company's allocation of margin should be adopted.

RUCO and Staff argue that cost of service is merely the starting point for designing appropriate rates. They contend that in addition to affording the Company revenue stability, other factors must also be considered in designing rates, such as affordability, gradualism, sending appropriate price signals, and conservation goals.

We agree with Staff and RUCO that designing rates is not an exact science that may be achieved by the application of a formula tied directly to a cost of service study. Rather, the formulation of just and reasonable rates is accomplished only through consideration of multiple factors that balances the desire of the Company to recover as much of its margin as possible with recognition of the legitimate interests of customers in paying rates that are affordable, as well as advancing societal goals. As discussed below, we have attempted to determine just and reasonable rates based on these competing principles and interests.

Single-Family Residential Gas Service (G-5)

[41] The residential rate class encompasses the vast majority of Southwest Gas customers and, not surprisingly, residential rate design garnered the most discussion and debate. Southwest Gas, Staff, and RUCO each proposed separate residential rate design recommendations.

Southwest Gas Proposal

Currently, Southwest Gas' single-family residential gas rates include an $8 basic monthly charge and a two-tier declining block rate of approximately $0.49 and $0.40 per therm, respectively. The break point between the first and second blocks is currently at 8 therms of usage in the summer (May-October) and 40 therms in the winter (November-April).

The Company has proposed an increase in the basic monthly charge from $8 to $16, and an increase in the first block volumetric charge from $0.49 to $0.66 per therm and a reduction in the second block from $0.40 to $0.25 per therm [FN5] (Tr. 283-287). Under the Company's proposal, the break point between blocks would remain at 8 therms during the summer months but would be reduced to 30 therms per month in winter months.

****25** Southwest Gas is critical of RUCO's rate design proposal because, in the Company's view, it does not shift enough of the volumetric charges to the fixed monthly charge and, by ***270** eliminating the declining block rate structure, it puts the Company at greater risk of not recovering its authorized margin (*See, e.g.*, Ex. A-51). With respect to Staff's recommendation, Southwest Gas concedes that low volume users will experience a significant increase in rates (Tr. 286-287). However, the Company contends that under either Staff's or RUCO's proposals, higher usage residential customers would fare substantially better under Southwest Gas' rate design because its second block rates would be reduced substantially compared to either current rates or the Staff and RUCO rates. Southwest Gas argues that its rate recommendation would be more beneficial to high volume residential customers, regardless of income, as evidenced by a chart in Mr. Congdon's testimony that shows substantial savings under the Company's plan for customers with usage over 100 therms in a given month (Ex. A-18, at 5). Based on its Exhibit A-50, which shows that usage by low income customers tracks closely the usage seen by non-low income customers,

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the Company argues that high use, low income customers may be affected even more dramatically because of an inability to pay increased costs associated with the higher second block rates under either the Staff or RUCO recommendations.

RUCO's Proposal

RUCO proposes an increase in the basic customer charge from $8 to $10.09 per month, and a flat volumetric rate of approximately $0.49 for all usage. According to RUCO, its rate design proposal gives recognition to the Company's concerns regarding revenue stability (*i.e* ., the Company's inability to recover margin costs due to declining per customer usage) by placing more cost recovery into the basic customer charge [FN6] , while also flattening the current two-tier volumetric structure to send appropriate price signals regarding gas consumption. RUCO witness Diaz Cortez indicated that RUCO's rate design proposal would mitigate the Company's risk of not recovering its authorized revenue requirement due to declining usage (RUCO Ex. 4, at 7).

Staff's Proposal

Based on its revenue requirement recommendation, Staff proposes an increase in the basic monthly charge from $8 to $9.70, accompanied by a two-tier commodity rate of approximately $0.54 for the first 15 therms in the summer and the first 35 therms in the winter, and $0.50 for usage in the second block. Staff claims that its proposed rate design moves significantly towards cost-based rates and properly balances the Company's revenue stability concerns with the concepts of gradualism, affordability, and conservation. Staff witness Bob Gray conceded that the Company's rate design recommendation provides greater rate stability than either Staff's or RUCO's proposals. He pointed out, however, that by 'front-loading costs in the customer charge and the first usage block,' the Company has offered a design that is inconsistent with Staff's goal of balancing stability with other important factors (Ex. S-15, at 9). Mr. Gray indicated it is 'mathematically impossible for a customer with low usage, paying a much higher customer charge and a much higher first block rate to not see a large rate increase'(*Id.* at 8).

Conclusion

****26** Although we are cognizant of Southwest Gas' desire to recover as much of its margin as possible through the monthly customer charge, it is simply untenable to saddle a substantial number of the Company's residential customers with rate increases in excess of 100 percent. Under the Company's recommendation, low usage residential customers would incur not only a doubling of their basic monthly charge (from $8 to $16 per month), but would pay a substantial commodity charge increase for usage up to 30 therms per month in the winter (from $0.49 to $0.66 per therm). While high usage customers may realize lesser overall increases under the Company's plan, relative to the Staff and RUCO proposals, the Southwest Gas rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in ***271** demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use, the more you save.'

We are also aware that customers will likely face additional cost increases associated with the Company's purchased gas adjustor ('PGA'). Southwest Gas expected to reach its ten cent PGA cap in January 2006, thus increasing customer bills associated with the cost of gas for a customer using 105 therms a month by approximately $10.50 per month, regardless of the rate design adopted in this proceeding (Tr. 297-298). The Company will also likely in the near future seek Commission approval for imposition of a surcharge to recover its $30 million bank balance, adding an additional $0.055 per therm (*i.e.*, an additional $5.50 per month for the same customer using 105 therms per month). Although the cost of gas may be largely beyond the Company's control, this additional rate impact must be considered as part of the overall rate impact on customers.

We agree with all parties that movement closer to cost-based rates is in principle a laudable goal. However,

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that goal must be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation. Based on consideration of competing interests and concerns, we agree that Staff's rate design recommendation appropriately makes significant movement towards cost based rates while providing a measure of protection for customers who will incur substantial rate increases as a result of this base rate case increase. Accordingly, we will adopt Staff's recommended basic monthly charge of $9.70 and, as adjusted for the revenue requirement adopted herein, a two-tier commodity rate of $0.54200 for the first 15 therms in the summer and the first 35 therms in the winter, and $0.50100 for usage in the second block.

Based on the G-5 residential rate design adopted in this case, and assuming an average monthly usage of 29 therms, single-family residential customers would experience an increase under summer rates of 8.9 percent, from $38.96 to $42.42 per month, and an increase under winter rates of 8.3 percent, from $39.71 to $42.99 [FN7].

Multi-Family Residential Gas Service (G-6)

27 **[42] Southwest Gas proposes creation of a new multi-family residential rate schedule (G-6) that would, under the Company's revenue requirement recommendation, grant customers in multi-family residences a $1 per month reduction to the basic monthly charge compared to single-family residence customers (*See*, Ex. A-2, Sched. H-3). Mr. Congdon stated that creating this separate rate schedule for multi-family residence customers would allow the Commission to moderate the effect on the Company's smallest residential customer class as residential service rates are moved gradually towards cost of service (Ex. A-17, at 26-27). RUCO does not oppose this recommendation.

Staff witness Gray testified, however, that although Staff is not strongly opposed to creation of a multi-family residential rate class, Staff does not believe it is advisable to create a separate rate structure for a small segment of the general rate class. Mr. Gray stated that while there are likely other segments of the residential class that have different characteristics, 'a Balkanization of the residential rate class absent a compelling need to do so is not something Staff will support' (Ex. S-15, at 10).

We agree with Southwest Gas that customers in multi-family dwellings deserve a separate rate categorization to reflect their lower usage characteristics and relatively lower cost to serve as a class. Therefore, we will approve creation of a separate rate schedule for this residential customer class and, consistent with the Company's proposal, impose a basic monthly service charge of $8.70, plus the commodity charges applicable to Schedule G-5 customers.

Based on the rate design adopted in this case, and assuming an average monthly usage of 29 therms, customers in the new multi-family residential class would experience an increase under summer rates of 5.5 percent, from $38.96 to $41.09 per month, and an increase under winter rates of 8.3 percent, from $39.71 to $41.54 [FN8].

*272 *Low-Income Residential Gas Service (G-10)*

[43] Southwest Gas proposed elimination of its low-income residential gas service tariff (G-10), with such customers being incorporated into the other residential classes (G-5 and G-6), and the current volumetric discount would be extended to the entire year rather than the current applicability to only winter months (Ex. A-17, at 27-29). However, the Company's proposal would lessen the amount of the discount applicable to low-income customers based on its assertion that there would be less of a need to shield such customers from high winter bills because the Company's rate design proposal, if adopted, would shift a portion of the margin recovery from the winter season to the summer season. Under the Southwest Gas recommendation, the existing $7.00 per month basic customer charge would be retained for low-income customers, and the current 20 percent discount on the first 150 therms of usage during winter months would be replaced with a year-round 15 percent discount with no usage limit. RUCO does not oppose the proposal and the Company indicates that it has not received any opposition to the proposal from local community action advocates after explaining the

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plan to those representatives (*Id.* at 28-29). Mr. Congdon testified that, if the Commission does not accept the Company's rate design proposal, the current 20 percent low-income discount should not be modified (*Id.*).

****28** Staff opposes the Company's proposal to eliminate Schedule G-10 and modify the low-income residential rate as described above. Staff witness Gray stated that Arizona utilities that offer such a discount typically have a separate, stand-alone tariff and Staff believes maintaining the existing tariff allows a higher profile for the tariff and advances ease of understanding. Mr. Gray agreed with the Company that the $7.00 customer charge for Schedule G-10 should be maintained at that level, and further indicated that the existing 20 percent discount for the first 150 therms of usage during winter months should be maintained because bills incurred for high winter usage is the critical element for low-income customers (Ex. S-15, at 36-38).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the low-income tariff. We agree with Staff's recommendation that the current Schedule G-10 should be maintained at its current level and we therefore adopt Staff's proposal to maintain the $7.00 customer charge and apply a 20 percent discount to the first 150 therms of consumption during winter months.

Special Residential Gas Service for Air Conditioning (G-15)

[44] Southwest Gas recommended that its special residential service tariff for gas air conditioning (G-15) should be eliminated and the small number of customers covered under the tariff folded into the general residential tariff (G-5). Company witness Congdon explained that there is currently only a small difference in the second block rate between the two schedules and the Company's proposal would eliminate the need to administer a separate schedule for this small number of customers. Mr. Congdon added, however, that if the Commission adopts the rate designs proposed by either Staff or RUCO, the G-15 schedule should remain intact and the summer air conditioning margin rate should be set at $0.25 per therm (Ex. A-17, at 29).

Staff witness Gray opposes elimination of the G-15 tariff because typical usage by customers under this schedule is significantly higher than general residential usage. Given this usage pattern differential, Mr. Gray indicated that it is reasonable to continue the separate tariff. Staff recommends that the G-15 tariff should continue to reflect the G-5 tariff rates, with the exception that the G-15 second summer usage block should be increased from approximately $0.19125 to $0.28200 per therm (Ex. S-15, at 41-42; Ex. S-16).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the residential air conditioning tariff. We agree with Staff's recommendation that the current Schedule G-15 should be maintained***273** at its current level, with the exception of an increase to the summer second block.

Master Metered Mobile Home Park Gas Service (G-20)

[45] In its application, Southwest Gas proposed increasing the basic monthly charge for master metered mobile home park service customers from $50 to $100, and increasing the commodity charge from approximately $0.314 to approximately $0.323 per therm (Ex. A-1, Sched. H-3). The Company did not present testimony on this issue, but argues that its recommendation better reflects its cost of service for this customer class, compared to Staff's proposal (*Id.*, Sched. H-6).

****29** Staff witness Gray stated that Staff's recommendation is to increase the basic monthly charge from $50 to $60, and to increase the volumetric charge from $0.31415 to $0.38400 per therm (Ex. S-16).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff.

General Gas Service (G-25)

With respect to the Company's recommendations re-

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garding this rate schedule, which includes various sizes of commercial customers, the following issues are addressed below: moving current Armed Forces customers on Schedule G-35 into Schedule G-25; appropriateness of creating a new sub-class for small use customers in the class and relative basic customer charge increase recommendations for different size customers within the class; and use of coincident peak or non-coincident peak for determining the demand charge for large G-25 customers.

Elimination of Armed Forces Rate Schedule (G-35)

[46] In its application, Southwest Gas recommended elimination of Armed Forces Rate Schedule G-35, and movement of existing customers under that schedule into the large general gas service rate under Schedule G-25. The basis of the Company's proposal is that if G-35 customers were permitted to choose to take service under either G-25 or G-35, the Company would experience a shortfall in margins.

DOD witness Dan Neidlinger filed testimony supporting Southwest Gas' recommendation, stating that DOD customers should logically be classified with other large gas users for ratemaking purposes. Mr. Neidlinger's testimony indicates that if the overall revenue requirements are established near the levels recommended by Staff or RUCO, DOD recommends adoption of RUCO's proposed G-25 rates (DOD Ex. 1, at 2-3).

Although Staff initially suggested that Schedule G-35 should be maintained and customers should be able to choose between G-25 or G-35 (Ex. S-15, at 43-47), Mr. Gray subsequently withdrew Staff's opposition based on DOD's agreement with the Company's proposal (Tr. 1097-1098).

Given Staff's acquiescence on this issue, we will adopt the Company's proposal to eliminate Rate Schedule G-35 for Armed Services customers and to include those customers under the large general gas service tariff, Schedule G-25.

New Sub-Class for Small Use Customers and Basic Service Charge Recommendations

[47] Southwest Gas' Schedule G-25 currently includes discrete prices for small (annual 0-7,200 therms), medium (annual 7,201-180,000 therms), and large (annual usage greater than 180,000 therms). The Company proposed the creation of a new sub-class within the small customer category, so that commercial customers with very low usage (*i.e.*, less than 600 therms annually) would be separated for rate design purposes from other small group customers that use between 601 and 7,200 therms annually (Ex. A-16, at 17-18). Mr. Congdon testified that the Company's proposal would allow pricing that more closely matches its cost of service while also mitigating the ***274** impact of the rate increase on the smallest customers within the class. He claimed that the Company's proposed tariff adjustments were made to minimize the differences in monthly bills at the cross-over volumes between general service rate schedules (*Id.* at 19).

****30** RUCO does not oppose creation of this sub-class category, but Staff contends that the members of the new sub-class 'would see a much larger rate increase than if they had remained part of the current small commercial class presently in existence' (Ex. S-15, at 43). Therefore, Staff witness Gray recommends retaining the current usage levels for small, medium and large G-25 customers (*Id.* at 44).

The proposals for customers within the G-25 rate schedule, including the Company's claimed cost of serving the customer classes (Ex. A-1, Sched H-6), are as follows (Ex. A-17, at 30-32):

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Proposed Schedule	Current	Staff	RUCO	SWG	Cost of Serv.
Small GS	$20.00	$24.00	$34.57	$25.00	$74.86

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Medium GS	20.00	24.00	48.39	35.00	79.02
Large GS	90.00	105.00	207.00	150.00	145.81
Transport Elig.	500.00	540.00	1,037.00	750.00	754.99

Based on our review of the record, we find the Company's recommendation to create a separate sub-class of very small customers is reasonable and should be adopted. However, in order to mitigate the severity of the customer charge increases on customers in this class, we will adopt a modified increase in the customer charges as follows: customers in the new small use segment - $25.00; customers in the medium class - $33.00; customers in the large class - $145.00; and customers in the transportation eligible class - $720.00. We believe these approved customer charges move the customers in this rate schedule closer to the Company's cost of service while, at the same time, protecting customers from dramatic increases in rates.

Demand Charge Determination

[48] Southwest Gas also proposed to change its method of measuring a large customer's peak demand from a coincident peak method (*i.e., system* peak month) to a non-coincident peak method (*i.e., customer* peak month). The Company claims that its non-coincident peak measurement would take some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis (Ex. A-17, at 33).

Staff opposes changing the demand charge calculation formula from use of coincident peak due to the potential that 'some customers may have structured their consumption and operations such that they reduce consumption on what is likely to be [the Company's] peak month' and, therefore, the change could have a significant rate impact on customers who have very different coincident and non-coincident peaks (Ex. S-15, at 44).

DOD agreed with the Company's recommendation, in part. DOD witness Neidlinger stated support for a modified non-coincident peak method 'whereby a customer's billing demand would be based on the highest monthly demand experienced during any winter month' (DOD Ex. 1, at 3). DOD would exclude from the calculation demands during the summer months of May through September.

Although we believe DOD's proposed modification of the non-coincident peak method for determining the demand charge has merit, ***275** there is not sufficient data in the record to support its adoption. We will therefore adopt the Company's non-coincident peak measurement recommendation as a means of taking some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis.

Air Conditioning Gas Service (G-40)

****31** Southwest Gas proposed the imposition of a single basic service charge of $25 for customers taking service under this tariff, rather than the Company's otherwise applicable basic service charge (Ex. A-16, at 14). However, the Company offered no testimony explaining the need for a distinct basic service charge for this tar- iff.

Staff witness Gray stated that the Company has a number of tariffs where the basic service charge is set by what it would be on the customer's otherwise applicable tariff, and this is the only tariff where Southwest Gas is proposing such a change (Ex. S-15, at 48).

We agree with Staff that there does not appear to be any reasonable justification for why the current tariff should be changed and it is more reasonable to have a larger basic service charge for a large commercial customer under the tariff compared to a small commercial customer taking service under the tariff (*Id.*). We therefore adopt Staff's recommendation on this issue.

Gas Service for Compression on Customer's Premises (G-55)

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[49] Southwest Gas proposes increasing the basic monthly charge for customers taking service under Schedule G-55, gas service for compression on customer premises, from $8.00 to $12.00 for residential customers; from $20.00 to $25.00 for small customers; and from $170.00 to $350.00 for large customers. The Company also proposes increasing the commodity charge from $0.13305 to $0.13669 per therm for all customers served under the G-55 tariff (Ex. A-1, Sched. H-3). Although Southwest Gas offered no specific testimony explaining the level of proposed increases, the Company claims that its proposal for increasing rates under the tariff reflect the Company's cost to serve this class of customers.

Staff witness Gray filed testimony recommending lesser rate increases. Mr. Gray recommended increasing the basic monthly charge for residential customers under this tariff from $8.00 to $9.70; small customers from $20.00 to $24.00; and large customers from $170.00 to $190.00 (Ex. S-13, at 49; Ex. S-16). He also proposed increasing the commodity charge from the current $0.13305 to $0.17000 per therm (*Id.*).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. However, since the small customer service charge is tied to Schedule G-25 (*i.e.*, $25.00), the customer charge for such customers shall be set accordingly.

Cogeneration Gas Service (G-60)

[50] Southwest Gas proposes that its cogeneration gas service tariff (G-60) be made available to all electric generation customers, with the exception that customers whose facilities exceed 5 megawatts ('MW') would be required to take transportation service at the Schedule G-60 rates. Company witness Congdon stated that this exclusion is necessary to eliminate 'the risk to Southwest Gas' sales customers associated with the procurement of the upstream gas supply and interstate pipeline requirements for these large customers' (Ex. A-17, at 35-36).

****32** Staff witness Gray testified that, although the Company expressed legitimate concerns regarding the possibility of significant new electric generation loads straining its system, Staff recommends that Southwest Gas should develop provisions of the G-60 tariff that would provide sufficient protections for the system and other core customers (Ex. S-13, at 50-51). Mr. Gray indicated that, in his opinion, it would be unfair to impose a provision that has the effect ***276** of potentially barring certain customers from taking service under this tariff due to the customer's size (*Id.*). Staff therefore proposes that the otherwise applicable general service and essential agricultural basic service charges should continue to be applied to G-60 customers, and that the per therm rate should be increased from $0.08934 to $0.11400 (*Id.* at 51; Ex. S-16).

We agree with Staff's recommendation regarding the Schedule G-60 tariff. We see no valid reason for restricting the Schedule G-60 tariff in the manner suggested by Southwest Gas. However, to the extent Southwest Gas believes additional protection for its system and core sales customers is necessary, the Company may separately propose in a tariff amendment filing, language that it believes would provide necessary safeguards.

Small Essential Agricultural User Gas Service (G-75)

[51] Southwest Gas proposed increasing the basic monthly charge for customers taking service under the small essential agricultural user gas service tariff (G-75) from the current $75 per month to $150 per month, and increasing the Schedule G-75 commodity charge from $0.19468 to $0.22186 per therm (Ex. A-1, Sched. H-3). The Company also recommends freezing Schedule G-75 so no new customers could take service under the tariff and would instead be required to be served under the general service tariff, Schedule G-25. Currently, customers may choose to be served under either Schedule G-75 or the general service tariff, G-25. According to Southwest Gas, its request to reclassify customers on the G-75 tariff is consistent with Decision No. 58377 (August 12, 1993) in which, according to the Company, the Commission suggested that customers under this schedule be moved to the general service tariff 'and to

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gradually eliminate Schedule G-75' [FN9] (Southwest Gas Initial Brief at 60).

Staff witness Gray testified that Staff opposes closing Schedule G-75 because elimination of the tariff would remove the option that currently exists for eligible agricultural customers to choose between general service and the G-75 tariff. Mr. Gray stated that 'absent a powerful reason to take this service option away' the G-75 tariff should be retained (Ex. S-13, at 52). In his surrebuttal testimony, Mr. Gray indicated his belief that the Company has not presented a compelling reason why eligible new customers should be precluded from exercising the same option that currently exists (Ex. S-15, at 12). With respect to the applicable charges, Mr. Gray recommended that the basic service charge should be increased from $75.00 to $90.00, and the per therm rate should be increased from $0.19468 to $0.22300 (Ex. S-13, at 52; Ex. S-16).

**33 Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. We agree with the principles stated in Decision No. 58377, that charges for this agricultural tariff should continue to move *gradually* closer to cost of service and the general service rate. However, we do not believe the Company's proposal to double the basic monthly charge for such customers, and to freeze new customers from taking service under the G-75 tariff, is consistent with the goals set forth in that prior Decision or with principles of fundamental fairness.

Natural Gas Engine Gas Service (G-80)

[52, 53] As described by Company witness Congdon, customers served under the natural gas engine gas service tariff (G-80), use natural gas engines to pump water for agricultural irrigation (Ex. A-17, at 36-38). Mr. Congdon stated that the G-80 tariff serves customers in a very price sensitive market in which the customers may decide, based on the cost of gas service, to either switch to electricity to operate their pumps or simply not to irrigate and produce crops at all (*Id.*). In its application, Southwest Gas proposes to increase the basic monthly charge in the peak season (April-September) from $80 to $100, but reduce the commodity margin from the current rate of $0.16189 to *277 $0.15848 per therm (Ex. A-1, Sched. H-3). No customer charge applies during off-peak months (*Id.*). In support of its proposal, Mr. Congdon stated that it did not assign an increase in margin to this class of customers because the Company is concerned that it may lose some of the G-80 tariff customers due solely to increases in the price of gas, which gas cost is reset for this class semi-annually, on April 1st and October 1st (Ex. A-17, at 37). Due to these competitive concerns, Southwest Gas opposes Staff's recommendation to increase the margin recovery associated with the G-80 tariff class (*Id.*).

Staff witness Gray agrees that the off-peak basic service charge should remain at zero. However, he recommends that the on-peak customer charge should be increased from $80 to $95 per month, and the per therm rate should be increased from $0.16189 to $0.17700 (Ex. S-13, at 53; Ex. S-16). In his surrebuttal testimony, Mr. Gray stated that Staff took into account the Company's competitive concerns concerning the G-80 rate class, but 'Staff does not believe the potential for customers leaving a given rate class should totally exempt that rate class from bearing some, albeit small, portion of the overall rate increase' (Ex. S-15, at 12-13). He pointed out that, under Staff's recommendation, the Schedule G-80 customers would receive the smallest revenue increase (approximately 2.77 percent under Staff's revenue requirement proposal) of any rate class under Staff's recommended rate design (*Id.*).

We agree with Staff that the relatively small margin increase assigned to the G-80 tariff class is a reasonable outcome based on the competing concerns of all customers affected by this proceeding. Although we recognize that retention of customers on Southwest Gas' system may provide benefits to all customers, we are not inclined to broker prices between competing sources of energy by limiting increases that may otherwise be applicable to a given class of customers based on cost of service principles and other factors that are weighed in determining rates for all classes of customers. We will

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therefore adopt Staff's recommendation on this issue.

**34 *MISCELLANEOUS ISSUES*

Billing Determinants

[54] Billing determinants are established by developing an annualized number of bills and volumes for the test period under the Company's current rate schedules (Ex. A-16, at 3). Accurate billing determinants are important because if too few determinants are used, tariff prices would be set unnecessarily high and, likewise, too many billing determinants would result in tariff prices that are too low to capture the established revenue requirement (Tr. 241-244).

Company witness Congdon testified that the proposed billing determinants were compiled by taking the monthly recorded number of bills and therms, by rate schedule, for the 12-month test year period, with the following adjustments to the recorded bills and therms: (1) billing adjustments (to remove anomalies); (2) volume annualizations (customer specific adjustments to reflect a full year's consumption for each customer, excluding the residential and small commercial classes); (3) customer reclassifications (to move customers and volumes between tariff schedules to reflect end of test year composition); (4) weather normalization (to accurately depict monthly volumes under normal weather conditions); (5) customer annualizations (for residential and small commercial classes, captures seasonal nature of test year customer growth); and (6) reclassification of full margin transportation customers to present rate schedules (to reflect pricing at present rate schedules) (Ex. A-16, at 3-8).

Although Staff does not oppose the Company's proposed billing determinants [FN10] , RUCO witness Moore filed testimony reflecting modifications that RUCO believes are necessary to obtain accurate determinants. Mr. Moore initially revised the billing determinants to reflect updated bill frequency analyses, and imputed revised billing determinants into the Company's proposed rate design, and, finally, annualized the imputed billing determinants using the Company's pro forma adjustments (RUCO Ex. 5, at 5).

***278** In his Rebuttal testimony, Mr. Congdon identified several errors he believes were made in RUCO's calculation. He stated that RUCO improperly attempted to utilize the Company's actual recorded bills and failed to utilize the residential bill frequency analyses ('BFAs') which are necessary to correctly price the first and second block volumes of the existing rates. Mr. Congdon indicated that RUCO's analysis understated first block revenues by approximately 88 million therms, which resulted in those therms being priced at the lower second block rate, thereby understating residential revenues by $7.4 million (Ex. A-17, at 24-25). Mr. Congdon also claimed that RUCO improperly used ratios to distribute the Company's total proposed adjustments to bills and volumes.

In his Surrebuttal testimony, Mr. Moore stated that following review of a data request response and several telephone conversations with Southwest Gas, the Company was unable to provide a set of test year billing determinants that generate its test year recorded revenues. Mr. Moore claims that RUCO analyzed the BFAs provided by the Company and determined a set of determinants that accurately reflect the size of the test year customer base, its usage patterns, and that generate the test year recorded revenue. RUCO then added pro forma adjustments to create a normalized set of test year determinants to design a rate structure that would produce RUCO's recommended revenue requirement (RUCO Ex. 6, at 4-7). RUCO argues that it corrected whatever errors existed in its initial calculation through its surrebuttal testimony and that the workpapers for those calculations were provided to the Company. RUCO claims that there is no assurance that the Company's proposal is any more accurate than RUCO's revised calculations.

**35 The Company provided a response to a RUCO data request to clarify the alleged errors, but Mr. Congdon claimed in his Rejoinder testimony that RUCO's continued insistence on adjustments to bills and volumes reflected several computational errors including: improper calculation of the Company's average test year cost of gas; incorrect pricing of bills and volumes

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for the Company's former Black Mountain Gas Company customers; and improperly pricing the gas cost and basic service charge revenue applicable to Schedule G-60 and G-80 (Ex. A-18, at 9-13). Despite attempting to reconcile RUCO's adjustments through data requests and telephone conversations, Mr. Congdon believed that RUCO's proposal continued to understate residential gas cost by $6 million, and overstated residential margin by the same amount (*Id.* at 12). On cross-examination, Mr. Congdon testified that the billing determinants proposal in RUCO's Surrebuttal testimony was closer than its original calculation, but RUCO's number of bills was still approximately 22,000 higher than the Company's calculation and RUCO's volumes were overstated by approximately 5 million therms (Tr. 244).

It is fairly clear that Southwest Gas and RUCO never achieved a meeting of the minds regarding the appropriate billing determinant methodology. There is little doubt that RUCO's initial calculations were flawed and, although subsequent amendments were made to its proposal, for the reasons identified by Mr. Congdon we believe that the billing determinant recommendation presented by Southwest Gas is the most reliable proposal and should be adopted in this proceeding (subject to the Staff modifications discussed above). In future cases, the parties would be wise to initiate discovery regarding complex issues such as this at an early stage in order to avoid the necessity of amendments to their recommendations at a later stage in the process.

Purchased Gas Adjustor

[55, 56] All of Southwest Gas' core customers are served under a purchased gas adjustor ('PGA') mechanism [FN11] . The PGA mechanism uses a 12-month rolling average, whereby a new PGA rate is calculated each month. Each month the Company calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then determined by subtracting the base cost of gas [FN12] from the 12-month average cost of gas. As explained by Staff witness Gray, the PGA rate is 'banded,' which means each month ***279** when the PGA rate is set it cannot be set at a rate that is more then $0.10 per therm different than the rate that was in place in any of the previous 12 months (Ex. S-13, at 8). The PGA currently has a $22.4 million bank balance 'trigger,' such that if the balance becomes over-collected by $22.4 million or more, the Company is required to take certain actions to address the under-collected balance (*Id.* at 18).

Staff made several recommendations regarding the PGA mechanism. Staff proposed that the base cost of gas should be set at zero and the full commodity cost of gas incorporated into the PGA. Staff also recommended that the current $22.4 million bank balance trigger should be increased to $29.2 million and an officer of Southwest Gas should be required certify each PGA report. Each of these issues is discussed below. Staff further recommended that the bank balance interest rate should be set based on the one-year nominal Treasury constant maturities rate, and that the PGA report should identify certain additional details regarding purchases and usage [FN13] . These issues are not in dispute and are not addressed further. The reporting details recommended by Staff are in addition to all current reporting requirements. Further, the Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

Setting Base Cost of Gas at Zero

****36** The base cost of gas is currently included along with the margin within the tariffed rate per therm for each rate class, with the monthly PGA listed as a separate line item on customer bills. Mr. Gray explained that in a rate case the Commission traditionally addresses all costs aside from the cost of gas component, which is treated separately through the PGA function. Because the margin rate recovers all of the other costs, such as metering, billing, customer service, personnel, and facility costs, the rates established in a proceeding such as this affect only the margin rate component, consisting of the tariffed rates and the basic service charge. As a result, the margin rate change for a given customer class is always much higher than the percentage increase on customer bills, given the treatment of the cost of gas component as a constant in the rate proceeding. Mr.

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Gray pointed out that including both a margin component and a base cost of gas in the tariffed (commodity) rate can result in significant confusion for customers who are trying to understand their bills, especially after rate increases are granted (Ex. S-13, at 8-16).

Southwest Gas' current base cost of gas is $0.37034 per therm, as established in the Company's last rate case (Decision No. 64172). In its application, Southwest Gas proposed increasing the base cost of gas to $0.53436 per therm, which Staff found to be reasonable. However, Staff witness Gray recommended, as an alternative, that the base cost of gas be set at zero as a means of minimizing customer confusion. Under Mr. Gray's recommendation, setting the base cost of gas at zero would effectively eliminate the base cost of gas component so that the PGA rate would include the previously separate base cost of gas amount. Thus, a single line item on customer bills would include the full commodity cost (absent a temporary surcharge or credit), allowing customers to easily see the changing cost of gas component separate from the margin component (Ex. S-13, at 13).

In order to alleviate short-term customer confusion from such a change, Staff further recommends that Southwest Gas should create specific customer education materials to explain the change (including, *e.g* ., a side-by-side bill comparison under the old and new rate structures) (*Id.* at 14-15). Mr. Gray also points out that setting the base cost of gas at zero would cause the monthly PGA rate component to significantly increase, and well beyond what a typical application of the $0.10 therm band would enable the monthly PGA rate to reflect. To remedy this problem, Staff recommends that, when applying the $0.10 per therm band for the first 12 months after this Decision, Southwest Gas should compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA in prior months. Taking this approach ***280** would, according to Mr. Gray, provide a consistent benchmark for applying the $0.10 per therm band while transitioning to a base cost of gas of zero (*Id* . at 15-16).

****37** Southwest Gas indicated that it does not oppose Staff's recommendation to set the base cost of gas to zero (*Id.* at 14; Tr. 270). Mr. Congdon also testified at the hearing that the Company does not oppose Staff's recommendation to create specific customer education materials, 'like a bill stuffer' that would go out in customer bills to explain the change (Tr. 270).

We believe Staff's recommendation to set the base cost of gas at zero is appropriate and, once fully implemented, should enhance customer understanding of their bills. This proposal will allow customers to more easily track the separate components that go into the provision of gas service, especially the gas component during periods of volatility. We appreciate Staff's effort in devising this recommendation, as well as the Company's agreement with a proposal that should minimize customer confusion, while at the same time allowing the Company to recover its costs. As a final matter on this issue, we direct the Company to submit to Staff for its review a copy of all customer education materials related to this issue prior to the materials being distributed to customers.

PGA Mechanism Trigger Level

[57] Southwest Gas' current PGA mechanism was implemented in June 1999, at a time when natural gas prices had remained relatively stable for a number of years. Staff witness Gray testified that, although no PGA structure can change or mitigate the fact that natural gas prices have increased dramatically in recent years, Staff believes the current PGA mechanism reasonably balances the protection of customers from wildly fluctuating gas prices with the goal of sending, to a certain extent, price signals to customers regarding gas prices (Ex. S-13, at 17). Therefore, Staff recommends that the existing PGA mechanism should be retained, subject to the limited modifications discussed below.

Mr. Gray explained that when the rolling average PGA mechanism was established by Decision No. 61225 (October 30, 1998), the $22.4 million trigger level was set on the basis of consumption levels for Southwest Gas in 1996 and 1997 (approximately 447 million therms annually). For 2003 and 2004, the Company had an average annual consumption of 516 million therms (*Id.* at 18). Mr. Gray stated that although there is not ne-

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cessarily one right trigger level, given the increasing annual cost of gas (among other relevant considerations regarding the impact on customers and the Company), Staff believes the trigger level for the PGA bank balance should be increased from $22.4 million to $29.2 million. According to Staff, the proposed trigger level increase should provide a level of flexibility to absorb higher usage and higher natural gas costs in the PGA bank balance, while also providing a measure of protection for customers and the Company if a positive or negative balance were to be carried within the balance for a period of time (*Id.* at 19-21).

Company witness Gieseking testified that while Southwest Gas is not necessarily opposed to an increase in the PGA bank balance trigger level, to the extent such an increase were to be adopted the Company believes the current $0.10 per therm PGA adjustment rate band should also be increased to $0.20 per therm [FN14] (Ex. A-21, at 10-11). Company witness Congdon stated that an increase in the bank balance trigger level would potentially increase the amount of money carried in the balancing account, thereby increasing the Company's business risk in the eyes of the financial community (Ex. A-17, at 40). Southwest argues that an increase in the adjustment cap would save customers in the long-term by minimizing deferrals to the balancing account, thereby reducing carrying costs on the PGA balance, and resulting in less cost to customers in a future period (*Id.*). Southwest Gas also contends that leaving the current $0.10 band in place would hinder the adjustment of gas rates that are used to reflect the 12-month average cost and would distort the true marginal cost of natural gas, thus failing to send appropriate price signals to customers (Ex. A-21, at 10-11).

38 *281 We agree with Staff that the PGA bank balance trigger level should be increased to $29.2 million for the reasons set forth in Staff witness Gray's testimony. As stated above, the Company is not opposed to the trigger level increase as long as the change is accompanied by a corresponding increase in the $0.10 per therm adjustment band. We believe that an increase in the trigger amount is a reasonable adjustment based on various factors, including the significant increase in gas consumption levels since the trigger was originally established.

Given the current volatility in the price of gas we believe a slight adjustment of the current adjustment band is appropriate. According to Mr. Gray, the purpose of the band is to limit the amount by which the monthly PGA rate could adjust automatically within a 12 month period, without further action by the Commission (Ex. A-15, at 5-6). Staff does not oppose an increase of the band in principle, but does not believe there is a need to link what it considers a moderate trigger level increase with an expansion of the adjustment band, as proposed by the Company (*Id.*). Although the trigger level and the adjustment band are not inextricably intertwined, limiting the band to its current level could result in greater long-term costs for the Company's customers. Mr. Gieseking testified that the Company's rolling 12-month average cost was expected to exceed the $0.10 upper band by January 2006, an indication that an increase in the band is warranted at this time. As Mr. Gray stated in his Rebuttal testimony, the band was expanded once before by the Commission, from $0.07 per therm to $0.10 per therm, and 'Staff is not conceptually opposed to a possible expansion of the band' (Ex. A-15, at 5). However, we believe the Company's proposed increase to $0.20 is excessive. We find that an increase to $0.13 per therm reflects a more reasonable balance between the interests of the Company and its customers.

Officer Certification of Monthly PGA Reports

[58, 59] Staff recommends that an officer of Southwest Gas be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. Mr. Gray stated that this recommendation is consistent with action taken by the Commission in other gas and electric cases dealing with adjustor mechanisms (Ex. A-13, at 24-25). Staff does not believe there is any basis for Southwest Gas to be treated differently than the other companies that are required to provide such certification (Ex. A-15, at 5).

Southwest Gas opposes Staff's recommendation to re-

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quire officer certification of the monthly PGA reports. Company witness Moody testified that although Southwest Gas is committed to providing the Commission with accurate information, the Company does not believe the certification requirement is necessary. Southwest Gas believes the person most knowledgeable regarding the report should sign it, as opposed to an officer (Ex. A-22, at 7; Tr. 454-455).

**39 We do not believe it is an undue burden for an officer of Southwest Gas to be required to familiarize herself or himself with the workings of the PGA mechanism and the monthly reports that are filed to support the required information. While Southwest Gas argues that Staff failed to provide a valid reason for why this requirement is necessary, the underlying basis of the Company's opposition rings hollow. The officer certification requirement would not only put Southwest Gas in a position that is comparable to other companies for which the issue has been addressed, but will provide a measure of assurance to the Commission, as well as the Company's customers and shareholders, that a level of oversight exists that reaches to the Company's highest ranks. Although we are not suggesting that Southwest Gas' prior PGA reports have been deficient, given the financial accounting scandals that have been exposed in the recent past, certification of a report that deals with millions of dollars of gas costs on a monthly basis seems a small price to pay for a higher level of oversight. Indeed, it is surprising that AUIA has not taken a position in support of Staff's recommendation given the inherent interest of shareholders in transparency and *282 accountability for a publicly filed report regarding the Company's purchased gas costs. We will therefore adopt Staff's recommendation.

Gas Procurement Practices

Staff witness Gray and William Gehlen conducted a detailed review of Southwest Gas' procurement practices during the test year, and offered several recommendations with respect to those practices. Mr. Gray identified price stability as one of the Commission's goals of the gas procurement process for Arizona LDCs, including Southwest Gas (*See*, Decision No. 61225).

Staff witness William Gehlen testified regarding the Company's procurement practices and indicated that having a mix of spot market gas and long-term fixed price contracts enhances price stability (Ex. S-8). Staff recommended that Southwest Gas further explore procurement opportunities in order to enhance greater price stability for customers. According to Staff, the Company has agreed to a number of recommendations, including: conducting a fuel and procurement practice best practices review; separating the contract award group from the invoice approval authority within the Company; reviewing the Company's portfolio evaluation software; eliminating the use of cell phones in term bidding and negotiating activities; and having a neutral party observe these activities (Tr. 433-434).

It is also Staff's position that employees involved in gas procurement should not have 'substantial' stock ownership in companies with which it is dealing (Tr. 1108). Company witness Moody agreed that Southwest Gas would review its definition of stock ownership rules for employees involved in gas procurement and meet with Staff within 60 days of the Decision in this case (Tr. 434).

Mr. Moody also agreed Southwest Gas shares Staff's concerns regarding El Paso, shortfall of service, and other lateral issues. It is Staff's recommendation that Southwest Gas should construct and own its laterals absent a compelling reason to do otherwise. However, Mr. Moody indicated that the best course of action is to take a look at a cost-effective and reasonable means for the Company to either own its system or own access to supplies that come onto its system. He explained that the Company has a long history of trying to purchase laterals from El Paso, but to do so would often require also purchasing undesirable lateral facilities (Tr. 455-456).

**40 Although there does not appear to be any dispute between the Company and Staff regarding these gas procurement issues, we direct the Company to initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed above, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the

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Company's system. Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

Interest on Customer Deposits

[60] In its Application, Southwest Gas proposed a reduction of the interest rate applied to customer deposits from 6 percent to 3 percent (Ex. A-29, at 31-32). As noted above, Staff proposed that the interest rate on PGA balances be set based on a monthly one-year nominal Treasury constant maturity rate (Ex. S-13, at 22). Staff also recommends that the same interest rate be applied to the Company's other balancing accounts (*i.e* ., DSM and LIRA) (*Id.* at 54). Company witness Congdon testified on rebuttal that an equitable approach to the customer deposit interest rate issue would be to synchronize the interest rates on both customer deposits and the balancing accounts maintained by Southwest Gas (Ex. A-17, at 39).

Staff witness Gray testified that Staff recommends maintaining the customer deposit interest rate at 6 percent consistent with the rate in effect for a wide variety of other utilities. Mr. Gray stated that although interest rates are currently relatively low, a significant rise in rates would not be equitable to customers if the customer***283** deposit interest rate were reduced to 3 percent as requested by the Company (Ex. S-13, at 57).

We agree with Staff that the customer deposit interest rate should be maintained at the current level of 6 percent. We believe that subjecting such deposits to a constantly varying interest rate could lead to customer confusion and would be inconsistent with the practices in effect for other utilities in the State. We therefore adopt Staff's recommendation on this issue. We also agree with Staff that maintaining the 12-month customer deposit period is appropriate.

Four-Hour Service Window

[61] In his Direct testimony, Staff witness Gray indicated that the Commission's Consumer Services Division has received a number of customer contacts expressing concern that Southwest Gas asks customers to be available at the service location for most or all of a day when a technician is scheduled for service. Mr. Gray stated that the Company's policy imposed a burden on customers and is inconsistent with the practices of other gas and electric utilities, which provide a four-hour window for service calls. Mr. Gray pointed out that the service window length is not established by Commission rule, but is set according to each company's practice. Mr. Gray recommended that Southwest Gas be required to establish a company practice of giving customers a four-hour window, in accordance with the policies in effect for other similar utility companies (Ex. A-13, at 54-55). Mr. Gray stated that there is no compelling reason why Southwest Gas cannot adopt the four-hour standard and he recommends that the Commission order the Company to adopt such a standard within 6 months from the date of this Decision (Ex. A-15, at 14).

****41** Company witness Palacios responded that a directive from the Commission is not necessary because Southwest Gas currently offers several service options including two-hour, four-hour, and eight-hour service windows 'based on the customer's request' (Ex. A-6, at 5). She indicated that only 10 to 15 percent of customers requesting service establishment (which requires entry into the premises) request service appointments of four hours or less. Ms. Palacios claims that if Staff's recommendation were adopted, Southwest Gas would likely have to increase its workforce to provide every customer, regardless of need, a four-hour service window (*Id.* at 4-5). She stated that such a mandate would also likely require significant restructuring of existing work practices and replacement of or major modification to the Company's customer appointment software. Ms. Palacios noted that gas utilities differ from electric companies because, for safety reasons, an employee must always enter the premises when service is established, and because service technicians must give their highest priority to emergencies which may interfere with their ability to meet four-hour window requirements (*Id.* at 6-7).

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We do not believe that the four hour service window requirement recommended by Staff would place an onerous burden on the Company's customer service capabilities. Mr. Gray testified that the Commission's Consumer Services Division has received comments regarding the lack of such a window being offered, and Staff's proposal to allow Southwest Gas 6 months to develop a program to meet this requirement is a reasonable length of time for compliance. Although the Company's witness attempted to distinguish electric from gas service providers to support the Company's position, she failed to recognize that UNS Gas, Inc. ('UNS') has a tariff in effect that requires appointments to be scheduled 'within a maximum range of four (4) hours during normal working hours' unless another time frame is established that is mutually agreeable to both UNS and the customer (Ex. S-27). Consistent with the tariff in effect for UNS, we agree with Staff that Southwest Gas should adopt a tariff which requires customers to be offered a maximum four-hour service window. Staff's recommendation is therefore adopted.

Energy Share Contributions

[62, 63] Southwest Gas currently participates***284** in the Energy Share program, which allows customers the opportunity to make voluntary contributions to help other customers with financial difficulties pay their utility bills. Other companies, such as APS and Salt River Project, also participate in the program, which is administered by the Salvation Army.

Staff witness Gray stated that Southwest Gas currently provides customers with a separate bill insert that can be returned with donations for Energy Share. In comparison, APS provides a box on its actual bills that can be checked and an amount indicated for donation. Staff recommends that, at the time the new rates from this proceeding are reflected on customer bills, Southwest Gas should provide a place on its customer bills to allow donations to the Energy Share program (Ex. S-13, at 55-56).

****42** In response, Company witness Congdon testified that Southwest Gas strongly supports retention of allowing customer contributions via bill inserts. He stated that the current practice should be maintained 'unless Staff presents clear and convincing evidence that a change in the program notification process would result in a greater benefit than its cost' (Ex. A-17, at 38).

We believe Staff's recommendation should be adopted. We appreciate Southwest Gas' participation in the Energy Share program. However, we agree with Staff that inclusion of a line on customer bills is preferable to a bill insert, which may be discarded when customers open their bills. We do not believe that a cost/benefit analysis is necessary to recognize that contributions are likely to be enhanced if, at the time customers sit down to write out their monthly checks, the opportunity to donate is clearly shown on the billing statements alongside the amount due. We believe Staff's recommendation represents a common sense approach to encouraging contributions to the program. The Company should implement this change within 60 days of the effective date of this Decision.

Gas Technology Institute

[64, 65] The Gas Technology Institute ('GTI'), which was formerly known as the Gas Research Institute, is a non-profit entity that does research, development and training regarding energy markets. GTI's Operations Technology Development ('OTD') programs focus on projects pertaining to pipe and leak locating and detection, reduced construction costs, gas main integrity and safety, while its Utilization Technology Development ('UTD') program focuses on developing increased-efficiency and safety end-use equipment for residential, commercial, and industrial gas customers. Although GTI was previously funded through a FERC surcharge, it now must solicit donations via state public utilities commissions and the LDCs they regulate (Ex. S-13, at 2-8).

Staff recommends that Southwest Gas participate in funding GTI's OTD and UTD programs at a level of $688,712 annually, which amount would be recovered on a per therm basis from the Company's sales customers, excluding G-30 and B-1 customers. Mr. Gray stated

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that the per therm surcharge would amount to approximately $0.00113, which would increase an average residential customer's bill by approximately three cents per month (*Id.*).

Southwest Gas witness Marti Marek testified that the Company supports funding gas research but opposes Staff's mandatory contribution of all research funding to a single entity. She indicated that, although the Company is pleased with the projects it has participated in with GTI, there are other competing research organizations that perform equally valuable work (Ex. A-24, at 2-6).

We agree with Southwest Gas that the funding provided for research should not be allocated to a single entity. The Company should have flexibility to tailor the research funds to the projects and organizations best suited for a specific need, subject to oversight by the Commission (*Id.* at 7). We will therefore adopt the recommended level of research funding, which would be collected through a surcharge, and held and disbursed through a balancing account. Adoption of Southwest Gas' proposal will allow the Company flexibility to select specific projects on a case-by-case basis, but will permit Staff to have input and oversight regarding the program expenditures.

***43** ***285** *Demand Side Management/Energy Efficiency Programs*

[66, 67] Southwest Gas proposed increasing its current level of demand side management ('DSM') funding of $600,000 per year to $4,385,000 annually [FN15] , subject to the Commission's approval of a decoupling mechanism. The DSM programs would be directed at all classes of customers instead of just residential customers as currently exists. The specific programs, and the associated funding proposed by Southwest Gas are as follows: Low-Income Energy Conservation ('LIEC') ($500,000); Energy Star Home Certification ($250,000); Multi-Family New Construction ($1,200,000); Residential Energy Construction ($200,000); Energy Star Appliances ($800,000); Food Service Equipment ($500,000); Efficient Commercial Building Design ($500,000); Technology Information Center ($35,000); and Distributed Generation ($400,000).

Staff, RUCO, and SWEEP/NRDC all support the DSM programs proposed by the Company, with a few minor exceptions. SWEEP/ NRDC witness Schlegel recommended that an additional $750,000 should be added to the Energy Star Home Certification program, and that Southwest should be allowed to impose a performance incentive mechanism to recover up to 10 percent of DSM funding if minimum goals are met (SWEEP Ex. 1, at 6). Company witness Vivian Scott testified in support of SWEEP/NRDC's proposals because she believes increasing funding for the Energy Star Home Certification program would enable the Company to expand the program to larger parts of its service territory (currently offered only in the Tucson area) (Ex. A-15, at 3). She also supports the performance incentive mechanism proposal which is comparable to a program in effect for APS (*Id.*).

Staff witness Steve Irvine supports the Company's initial proposed DSM funding level, with the exception of $50,000 included in the LIEC program that is specifically allocated for rate assistance to low-income customers. Mr. Irvine stated that such rate assistance is not DSM-related and should therefore be considered as a separate and distinct program (Ex. S-19, at 3). He acknowledged that a similar program was included in a recent APS case, but points out that the rate assistance component of that case was part of a settlement agreement involving a number of diverse parties. Mr. Irvine also opposes the SWEEP/NRDC proposal to increase the Energy Star Home Certification program by $750,000 on the basis that Southwest Gas previously indicated that 'the market has sufficiently transformed and that incentives are no longer necessary to ensure more energy-efficient construction'(*Id.* at 6) (*See also*, Decision No. 67878, June 1, 2005, granting Southwest Gas' request to reduce the annual Energy Advantage Plus program funding from $900,000 to $250,000). In addition to these adjustments to proposed DSM revenues, Staff recommends the following with respect to the Company's DSM programs: semi-annual DSM reports certified by an officer of the Company; requirement that Company docket within 120 days of this Decision, in a

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separate docket, detailed descriptions of the DSM programs that would be subject to Commission approval; requirement that the Company implement and maintain the collaborative DSM working group to solicit and facilitate input from any interested party (prior to submission to Commission of specific programs); responsibility of Southwest Gas to demonstrate appropriateness of specific DSM programs; and no performance incentive mechanism should be approved (*Id.* at 9-10).

**44 With one exception, we agree with Staff's recommendations regarding DSM. Despite Staff's concerns, we believe the $50,000 currently included in the LIEC program for rate assistance funding should be maintained. Although such funding may not in a strict sense be considered DSM-related, we agree with Mr. Schlegel that it represents a relatively small percentage of the overall DSM budget and is to be used for emergency situations for low-income customers. To the extent any portion of this $50,000 is not spent yearly on bill assistance emergencies, the balance should be allocated to general LIEC programs. With respect to SWEEP/ NRDC's proposal to increase by $750,000 funding for Energy Star Home Certification,*286 we share Staff's concern that the Company has previously offered conflicting views of whether such an increase in such funding would be cost effective. As Mr. Irvine pointed out, through data request responses the Company indicated that it could offer the program throughout its service area at the initial funding level and specifically requested a reduction in funding for a similar program in the Tucson area due to market transformation (Ex. S-19, at 6-7). We also agree with Staff that the performance incentive mechanism, which was suggested for the first time in Mr. Schlegel's testimony, is not sufficiently developed for approval at this time. The parties to the DSM collaborative process may wish to pursue this issue through further discussions but the proposal contained in the record of this proceeding lacks sufficient detail to determine whether it is appropriate at this time. In all other respects, we agree with and adopt Staff's recommendations as described above.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On December 9, 2004, Southwest Gas filed an application with the Commission for an increase in rates.

2. On January 7, 2005, the Commission's Utilities Division Staff filed a Letter of Insufficiency.

3. On January 26, 2005, Staff filed a Letter of Sufficiency, notifying the Company that its application met the sufficiency requirements and classifying Southwest Gas as a Class A utility.

4. By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.

5. Intervention was granted to RUCO, AUIA, DOD, SWEEP/NRDC, YCA, ACAA, APS, and TEP.

6. Southwest Gas filed Direct testimony with its application on December 9, 2004. Pursuant to Procedural Order issued March 10, 2005, Direct testimony was filed on July 26, 2005 by Staff, RUCO, YCA, AUIA, ACAA, and SWEEP/NCRA.

7. Rebuttal testimony was filed by Southwest Gas on August 23, 2005. Surrebuttal testimony was filed on September 13, 2005 by Staff, RUCO, AUIA, SWEEP/ NRDC, and DOD. Rejoinder testimony was filed by the Company on September 23, 2005.

8. An evidentiary hearing was conducted at the Commission's offices in Phoenix, Arizona commencing on October 3, 2005 and concluding on October 11, 2005.

9. Late-filed exhibits were filed by Southwest Gas on October 21, 2005 and November 4, 2005.

10. Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/ NRDC, AUIA, and Staff.

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11. Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/NRDC, AUIA, and Staff. Southwest Gas filed a Supplement to its Reply Brief on November 23, 2005.

12. According to the Company's application, as modified, in the test year Southwest Gas had adjusted operating income of $46,775,622 on an adjusted Original Cost Rate Base of $943,110,070, for a 4.96 percent rate of return.

13. In its application, as modified, the Company requested a revenue increase of $66,898,342, based on OCRB of $943,110,070, and rate of return of 9.24 percent.

14. Staff recommends a rate increase of $51,625,135, based on OCRB of $924,927,566, and a recommended rate of return of 8.40 percent.

15. RUCO recommends a revenue increase of $48,506,079, based on OCRB of $919,607,846, and recommended rate of return of 8.64.

16. For purposes of this proceeding, we determine that Southwest Gas has an Arizona Fair Value Rate Base of $1,169,584,038.

*287 17. A rate of return on FVRB of 6.63 percent is reasonable and appropriate.

18. Southwest Gas is entitled to a gross revenue increase of $49,345,636.

19. The Company's proposed Conservation Margin Tracker decoupling mechanism proposal is not adopted in this proceeding.

20. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

21. For residential customers under Schedule G-5, the basic monthly customer charge should be increased from $8.00 to $9.70, and a two-tier declining block structure remains appropriate in accordance with Staff's recommendation.

22. A separate multi-family residential basic monthly customer charge of $8.70 is appropriate under the new Schedule G-6 rate.

23. The low-income residential rate (G-10) should be maintained at its current $7.00 per month with the current commodity discount of 20 percent for the first 150 therms of winter usage.

24. Staff's rate design recommendations for Special Residential Gas Service for Air Conditioning (G-15) and Master Metered Mobile Home Park Gas Service (G-20) should be adopted.

25. The current Armed Forces Rate Schedule G-35 should be eliminated and customers currently on that schedule would receive service under Schedule G-25.

26. For General Gas Service customers on Schedule G-25, a new sub-class should be created for small customers using less than 600 therms annually, and the demand charge for large G-25 customers should be calculated based on DOD's recommendation of using a modified non-coincident peak during any winter month.

27. For Air Conditioning Gas Service (G-40); Gas Service for Compression on Customer's Premises (G-55); Cogeneration Gas Service (G-60); Small Essential Agricultural User Gas Service (G-75); and Natural Gas Engine Gas Service (G-80), Staff's recommended rate design should be adopted.

28. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

29. With respect to the Company's Purchased Gas Adjustor mechanism, the base cost of gas should be set at zero in accordance with Staff's recommendation; the trigger level for the PGA bank balance should be increased from $22.4 million to $29.2 million as recommended by Staff; and the current $0.10 per therm adjustment band should be increased to $0.13 per therm.

30. The interest rate for the Company's PGA, DSM, and LIRA balancing accounts should be based on the one-year nominal Treasury constant maturities rate, in accordance with Staff's recommendation.

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31. The Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

32. Staff's recommendation to require an officer of Southwest Gas to provide certification of the accuracy of the monthly PGA reports is reasonable and should be adopted.

33. Southwest Gas should initiate discussion with Staff within 60 days regarding gas procurement issues identified by Staff, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

34. The current interest rate of 6 percent on customer deposits should be maintained in accordance with Staff's recommendation. The 12-month customer deposit period should also be maintained.

35. Southwest Gas should develop within 6 months a tariff proposal that would require that customers be offered a four-hour window for service calls.

36. Southwest Gas should implement, within 60 days of the effective date of this Decision, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

37. Gas research should be funded at the level recommended by Staff, but Southwest Gas should have the flexibility, subject to Staff oversight,***288** to select appropriate entities for use of the research funds.

38. DSM programs should be funded at the level initially recommended by Southwest Gas ($4,385,000) and the Company should comply with the recommendations made by Staff regarding, among other things, compliance filings and working with the DSM collaborative group.

39. Arizona customer bills should contain information relevant to Arizona customers. Information specific only to Nevada and/or California customers should be removed from the back of Arizona customer bills. Furthermore, the back of Arizona customer bills should contain explanations for two billing line items 'Base Tariff Rate' and 'Rate Adjustment.'

40. We also agree with Staff that anytime Southwest Gas initiates participation in a new natural gas docket at the FERC which relates to its service in Arizona, the Company should be required to provide Staff with a copy of Southwest Gas' initial filing in that FERC docket.

****45** *CONCLUSIONS OF LAW*

1. Southwest Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250, 40-251 and 40-367.

2. The Commission has jurisdiction over Southwest Gas and the subject matter contained in the Company's rate application.

3. The rates, charges and conditions of service established herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that Southwest Gas Corporation is hereby authorized and directed to file with the Commission, on or before February 28, 2006, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after March 1, 2006.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall notify its customers of the revised schedules or rates and charges authorized herein by means of an insert in its next regularly scheduled billing, in a form acceptable to Staff.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide a detailed ex-

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planation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its customers.

IT IS FURTHER ORDERED that Southwest Gas Corporation should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall submit to Staff for its review a copy of all customer education materials related to setting the base cost of gas at zero prior to the materials being distributed to customers.

IT IS FURTHER ORDERED that the Company's PGA monthly reports to the Commission shall continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

IT IS FURTHER ORDERED that, for all future PGA monthly reports, an officer of Southwest Gas shall be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

***289** IT IS FURTHER ORDERED that Southwest Gas Corporation shall initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed herein, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

****46** IT IS FURTHER ORDERED that Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall, within 6 months of the effective date of this Decision, propose a tariff which requires customers to be offered a maximum four-hour service window.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall implement, within 60 days of the effective date of this Decision and in a form acceptable to Staff, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall comply with the recommendations made by Staff regarding, among other things, DSM compliance filings and working with the DSM collaborative group.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

FOOTNOTES

FN1 Other intervenors in the proceeding raised non-revenue requirement issues which are discussed below.

FN2 The defective pipe was 1960s steel pipe, and plastic pipe known as Aldyl A, Aldyl HD, and ABS.

FN3 *Application of Southwest Gas Corporation for Increase in Rates* , Public Utilities Commission of Nevada, Order in Docket No. 04-3011 (August 30, 2004), at 41.

FN4 *Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Public*

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Service Commission of West Virginia, et al., 262 U.S. 679 (1923).

FN5 Southwest Gas proposed that if the CMT were adopted, the basic monthly charge should be increased from $8 to $12 per month, and the commodity charge would increase from $0.49 to $0.84 in the first block, and would decrease from $0.40 to $0.15 in the second block. Because we have not adopted the CMT, the rate design proposal described above is recommended by the Company.

FN6 RUCO claims that its recommendation would shift approximately $23 million per year from commodity charges to the basic service charge under current revenues and over $26 million under RUCO's proposed revenues in this case (Tr. 1003-1004).

FN7 An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 11.8 percent, from $18.94 to $21.18; and an average customer's winter usage in January (72 therms), where an average bill would increase by 8.1 percent, from $84.04 to $90.83.

FN8 An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 5.9 percent, from $18.94 to $20.06; and an average customer's winter usage in January (72 therms), where an average bill would increase by 6.1 percent, from $84.04 to $89.14.

FN9 Decision No. 58377 concurred with Staff's recommendation 'to retain the current SEA [small essential agriculture] rate schedule' (Decision No. 58377, at 42-43). Although the Decision directed Southwest Gas to 'gradually move the SEA schedule to the general service level,' the Commission specifically rejected Southwest Gas' request to close the small essential agriculture tariff to new customers because 'closure may unfairly treat identical customers '(*Id.* at 43). Contrary to the Company's assertion in its Brief, the Commission did not state in Decision No. 58377 that Schedule G-75 should be eliminated.

FN10 Mr. Congdon stated that Staff accepted the Company's proposed test year bills and volumes, but not all of the Company's proposed reclassifications of customers to new rate schedules. The Company agreed that, to the extent Southwest Gas' proposed rate schedules and customer reclassifications are not adopted, use of Staff's bills and volumes would be appropriate (Ex. A-17, at 26). To the extent we have adopted Staff's recommendations on the various rate schedule issues, as discussed above, Staff's bills and volumes will be employed accordingly.

FN11 Customers under Schedules G-60 and G-80 are served under a separate cost of gas which is reset twice annually, on April 1st and October 1st (Ex. A-13, at 8).

FN12 The base cost of gas includes both the commodity cost and the cost of transport from its source to the Southwest Gas distribution system.

FN13 Specifically, Staff recommends that Southwest Gas' report include a breakdown of 'purchases' into fixed price and variable (such as index) contracts, and that the Company begin identifying in its monthly PGA reports average and median usage levels for G-5 and G-10 rate schedules (Ex. A-13, at 25).

FN14 Southwest Gas initially proposed a corresponding increase in the adjustment band of only three cents, from $0.10 to $0.13 (Ex. A-17, at 40).

FN15 The DSM funds are collected through a DSM surcharge and held and disbursed through

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a balancing account.

**47 *290 EDITOR'S APPENDIX

PUR Citations in Text

[ARIZ.] Re Southwest Gas Corp., 146 PUR4th 54, Docket No. U-1551-92-253, Decision No. 58377, Aug. 12, 1993.

[ARIZ.] Re Southwest Gas Corp., 156 PUR4th 109, Docket No. U-1551-93-272, Decision No. 58693, July 7, 1994.

[ARIZ.] Re Southwest Gas Corp., 213 PUR4th 53, Docket Nos. G-01551A-00-0309, G-01551A-00-0127, Decision No. 64172, Oct. 30, 2001.

[NEV.] Re Southwest Gas Corp., 236 PUR4th 294, Docket No. 04-3011, Aug. 26, 2004.

[U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, 262 U.S. 679, PUR1923D 11, 67 L.Ed 1176, 43 S.Ct. 675 (1923).

[U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed 333, 64 S.Ct. 281 (1944).

[U.S.Sup.Ct.] West Ohio Gas Co. v. Ohio Pub. Utilities Commission, 294 U.S. 63, 6 PUR NS 449, 79 L.Ed.2d 761 (1935).

END OF DOCUMENT

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PUR Slip Copy

Re Aquila, Inc. dba Aquila Networks
Application No. NG-0041

Nebraska Public Service Commission
July 24, 2007

Before Signature, chairman, and Signature, Signature, Signature (concurring), And Johnson (dissenting), commissioners.

BY THE COMMISSION:

ORDER GRANTING APPLICATION IN PART

*1 On November 15, 2006, Aquila, Inc., d/b/a Aquila Networks (Aquila) filed an application seeking individual general rate increases for Aquila's Rate Area One, Rate Area Two, and Rate Area Three. Interventions were filed by Cornerstone Energy, Inc. (Cornerstone); Kinder Morgan, Inc., now known as SourceGas Distribution (SourceGas); and the Public Advocate.

In summary, Aquila sought a total revenue increase of $16.3 million and an overall rate of return of 9.6 percent. Aquila requested an increase in the residential customer charge from $11.00 to $16.00 per month. Furthermore, Aquila proposed a single residential volumetric charge of $0.14868 per therm for all three rate areas. [FN1]With respect to business ratepayers, Aquila sought an increase in the customer charge from $15.00 to $20,00 as well as a single business volumetric charge of $0.15803 for all three rate areas. [FN2]

In addition to the changes in the customer and volumetric charges, Aquila proposed an Energy Efficiency Rider to provide funding for Aquila's two proposed energy efficiency programs 1) space and water heating equipment rebates; and 2) Low-Income Weatherization. Aquila further proposed a Revenue Normalization Adjustment (RNA), a monthly adjustment accounting for variations in revenues received by the company; a Weather Normalization Adjustment (WNA), an automatic adjustment for variations in revenues attributable to weather; and a Limited Cost Recovery adjustment (LCR), which would provide automatic rate increases to the utility based upon inflation without the necessity of a rate application.

Hearing on this matter was held on May 30 and 31, 2007. Steve Pella; Richard Petersen; Ruth Gustin; Philip Beyer; Glenn Dee; Vern Siemek; and Paul Raab testified on behalf of Aquila. Kimberley Lillyblad; Albert Bartsch; and William Glahn testified on behalf of the Public Advocate. Additionally, several documents were entered into the record including copies of written testimony filed on behalf of Aquila, the Public Advocate, and Cornerstone Energy; all responses to data requests; summaries of customer contacts; and various work papers.

OPINION AND FINDINGS

'Every rate made, demanded, or received by any natural gas public utility shall be just and reasonable. Rates shall not be unreasonably preferential or discriminatory and shall be reasonably consistent in application to a class of ratepayers.' [FN3]

'The commission, in the exercise of its power and duty to determine just and reasonable rates for natural gas public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable natural gas service and to the need of the jurisdictional utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provisions for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.' [FN4]

'Cost of service shall include operating expenses and a fair and reasonable return on rate base, less appropriate credits.' [FN5]

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***2** With the exception of the items specifically addressed herein, the Commission grants Aquila's application subject to the adjustments and limitations discussed below.

RATE BASE

'The rate base of the jurisdictional utility shall consist of the utility's property, used and useful in providing utility service, including the applicable investment in utility plant, less accumulated depreciation and amortization, allowance for working capital, such other items as may be reasonably included, and reasonable allocations of common property, less such investment as may be reasonably attributed to other than investor-supplied capital unless such deduction is otherwise prohibited by law.' FN6

'The rate base shall ordinarily consist of those items which are used and useful in providing service to the public.' FN7 In calculation of rate base, Aquila has sought several adjustments.

'Post test year adjustments are permitted for known and measurable rate base adjustments to test year where the utility accounts for any related impacts on all aspects of the jurisdictional utility's operations. Related impacts are those that reasonably follow as a consequence of the post test year adjustment being proposed, including a related impact of another post test year adjustment.' FN8

Capital Additions

Aquila seeks a capital addition adjustment, which increases plant in service by $12,776,870.00 relating to construction work in progress.

Pursuant to *Neb. Rev. Stat.* § 66-1817,
(1) Any jurisdictional utility property may be deemed to be completed and dedicated to commercial service if construction of the property will be commenced and completed *in one year or less*. (2) The commission may determine that property of a jurisdictional utility which has not been completed and dedicated to commercial service may be deemed to be *used and useful* in the utility's service to the public.

Rate base 'may include items completed and dedicated to commercial service for which construction will be commenced and completed within one year or less from the end of the test year.' FN9

Aquila did not provide direct testimony specifically addressing the capital additions adjustment. However, work papers ADJ-1 to ADJ-18 were provided in the original filing and as Exhibit VJS-1 in rebuttal testimony. The work papers include a brief description of the project, the FERC account affected by the project, costs for 6 months in 2006 and 6 months of 2007 by rate area. Additionally, it includes a listing of the depreciation rate and depreciation expense. It also contains spreadsheets purporting to offer capital variance explanations and budgets for the various capital projects included in the adjustment.

Mr. Siemek further states in his rebuttal testimony that information regarding capital additions was provided in Responses to PA DR 20 and 69, which were included in Exhibits VJS-2 and VJS-3.

Aquila contends that the adjustment 'reflects the impacts of Capital Additions to be made by June 30, 2007' and that the additions 'impact plant in service, depreciation expense, and accumulated reserves for depreciation.' FN10 According to Aquila, 'The capital Additions Adjustment included only integrity projects since growth projects would have revenues to offset the investment. ' FN11

***3** The Public Advocate contends that the adjustment should be disallowed as Aquila failed to provide sufficient explanation in the record regarding the adjustment in order for the Commission to determine whether the additions are used and useful or whether the costs are known and measurable and prudently incurred. FN12On behalf of the Public Advocate, Mr. Glahn testifies, 'Without a witness to depose, to direct data request to, or to cross-examine under oath, inclusion of this Adjustment in the rate base, and, thus, in rates, raises obvious due process problems.' FN13

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The Commission is compelled to respond specifically to Mr. Glahn's contention that due process issues exist with respect to Aquila's presentation of evidence on this issue. The Commission finds that in light of the fact that specific data requests were made regarding this adjustment, and the witness who provided rebuttal testimony on this adjustment was available during the hearing, we find that no due process issues exist. However, in future rate cases, the Commission would expect utilities to provide direct testimony specifically addressing the substantive evidence on the adjustment.

Pursuant to § 66-1817, it is entirely within the Commission's discretion as to whether construction work in progress will be included in rate base. In this case, although some evidence was presented regarding the capital additions in progress, very little explanation was offered regarding the nature or status of the various capital addition projects. Furthermore, no specific explanations were given as to the reasons for or necessity of the projects. In light of the fact that this is a discretionary post test year adjustment, the Commission finds that Aquila did not provide sufficient explanation regarding this adjustment in order for the Commission to determine that the capital additions will be *used and useful* in the utility's service to the public and should be included in rate base immediately.

In future filings, the Commission would expect that direct testimony include a discussion of each project; why the utility has determined that the project is necessary to the provision of safe and reliable gas service; and how the project costs are being financed, whether through debt or internally generated cash. Additionally, the utility should describe why it is necessary for the project to be included in rates before it is complete and in service.

Evidence presented should include a list of all construction projects the utility is requesting to include in plant in service which should include a description of the project; location of the project; purpose for the project; date construction was begun; expected completion date; actual costs incurred as of the last day of the test year; and finally total expected cost for the project at completion.

Offutt Housing

Aquila seeks an adjustment, related to the privatization of Offutt Air Force Base housing, which increases plant in service by $1,094,690.00, reduces test year revenues by $362,965.00, reduces the cost of sales by $290,372.00, increases operating expenses by $93,663.00 and reduces sales volumes by 50,957. [FN14] The project will include 'demolition, abandonment, renovation and rebuilding to yield 1,631 modernized units by 2011.' [FN15] Aquila asserts that the adjustment is necessary 'to properly reflect and match margins, costs and investments included in the test period to the margins, costs and investments after the project is completed.' [FN16]

***4** The Public Advocate presented evidence that this constitutes a 'selective adjustment' [FN17] as Aquila 'has not seen fit to include any expansion projects, currently under construction that would increase revenues.' [FN18] The Public Advocate recommends that this adjustment be denied. [FN19]

The expected completion date of this project is well beyond the test year, rendering this adjustment speculative and therefore not 'known and measurable'. However, the Commission has the discretion to allow Aquila to include in its rate base 'property which has not been completed and dedicated to commercial service'. [FN20]The Commission attempted, based upon the information in the record, to determine whether there was a portion of the adjustment that could be allowed because the investment was already made. However, no such determination could be made with the information available. Therefore, the Commission finds that it would be inappropriate to include estimates for costs associated with a construction project scheduled to be completed a full five (5) years after the test year and this adjustment is disallowed.

Gas In Storage

Aquila seeks an adjustment to rate base of $18,157,457 based on the estimated volumes and price of gas planned to be in storage at December 31, 2006, six

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months after the end of the test year.

The Public Advocate agrees that a Gas Storage adjustment is appropriate but recommends that the amount of the adjustment be based upon average monthly gas in storage inventory amounts for the twelve-month period corresponding to the test year. [FN21]Mr. Bartsch testified that 'The use of the projected inventory in any one month, when the gas in storage varies significantly throughout the test year, will result in a totally inappropriate adjustment either in a positive or in a negative direction.' [FN22] Mr. Bartsch proposes an adjustment of $11,184,632. [FN23]

As with other post test year adjustments to the rate base, Aquila must show that this asset is 'used and useful' in the provision of natural gas service and that the amount of the adjustment is 'known and measurable'. Aquila has proposed valuing gas in storage based upon a single point in time which does not provide an accurate representative valuation of the asset. Mr. Dee acknowledged that the balance of gas in storage varies throughout the year with the highest storage levels occurring from October through December and the lowest levels occurring from April to May. [FN24]The Commission finds that an adjustment for gas in storage is appropriate as it is 'used and useful' in the provision of natural gas service. However, we further find the Public Advocate's recommendation that a twelve-month average of historic data over the test-year period is a more appropriate method for determining a 'known and measurable' adjustment in this context.

Cash Working Capital

An additional component of rate base is an allowance for working capital. [FN25]The allowance for working capital includes '[a] prudent allowance for cash working capital.' [FN26]

*5 Cash working capital is a component of invested capital or rate base. Aquila proposes to include a $3,344,444 cash working capital allowance in rate base, which Aquila calculated based on a lead/lag study. On Exhibit VII, Schedule A, page 1 of its filing, Aquila explains that 'Lead/lag measures the amount of cash working capital needed by looking at the timing difference between when cash comes in and when it is disbursed for various expenses. ' While a lead/lag study is the best method for measuring cash working capital, there are many opportunities to impact the outcome.

Mr. Glahn explains 'Ratepayers pay a return to investors on working capital to the extent the capital is supplied by investors.' [FN27] He points out at page 41 of his direct testimony that Aquila failed to include two sources of non-investor supplied cash in its lead/lag study: city franchise fees and sales tax. Relying on Aquila's responses to Public Advocate Data Requests PA-87 and PA-112, Mr. Glahn calculated the lag for franchise fees and concluded that including this lag in the lead/lag study reduces cash working capital by $1,609,722. [FN28]Relying on Aquila's responses to Public Advocate Data Requests PA-113 and PA-114, Mr. Glahn calculated the lag for sales tax to be 40 days, which reduces Aquila's cash work capital allowance by $271,632. Mr. Glahn recommends that Aquila's cash working capital allowance be reduced by these amounts, which total $1,881,354.

Mr. Dee argues, in his rebuttal testimony, that 'neither franchise fees nor the sales tax collected are sources of working capital' according to Mr. Glahn's definition. While Mr. Dee does not specifically reference the definition to which he refers, Mr. Glahn states at page 40 at lines 7 and 8: 'The amount of working capital a company needs depends upon its revenue stream and expenses.' Mr. Dee claims at pages 5 and 6 of his rebuttal testimony that 'franchise fees are not inventories, prepayments, revenues, or expenses' and, therefore, should not be included in the lead/lag study. He makes the same argument with respect to sales tax.

Mr. Dee argues in his rebuttal that Mr. Glahn erred in his calculation of the lead days for both franchise fees and sales tax. Mr. Glahn's calculation of the lead on sales tax assumes that Aquila remits sales tax to the state after it is collected from Aquila's customers. Mr. Dee stated during cross examination that sales tax is owed to the state after it is billed. Mr. Dee recalculated the impact on cash working capital for both sales tax

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and franchise fees in his rebuttal testimony. His calculations indicate that franchise fees provide a source of cash working capital of $277,333, while sales tax creates a need for working capital of $266,417. The net difference is a source of cash working capital of $10,916.

The Commission agrees with Mr. Dee's calculations of the impacts of these two items on Aquila's cash working capital needs. Because the impact demonstrated by Mr. Dee is *de minimis*, the Commission concludes that Aquila's requested cash working capital of $3,344,444 is reasonable.

OPERATING EXPENSES

***6** 'Operating expenses shall consist of expenses *prudently incurred to provide natural gas service* including (a) a reasonable allocation of common expenses as authorized and limited by section 66-1819 and (b) the quantity and type of purchased services regulated by the Federal Energy Regulatory Commission.' [FN29]

Contributions, Donations and Dues

If a jurisdictional utility seeking a general rate increase wishes to include in its operating expenses any 'funds expended in support of or membership in social, recreational, fraternal, or religious clubs or organizations' each must be separately identified in its financial summary. [FN30]Aquila seeks to include fifty percent of such expenses. The Commission will first address contributions and donations, followed by membership dues and fees.

With respect to contributions to community associations and organizations, Mr. Pella testified 'Aquila is rightfully expected to make contributions to community associations and organizations ...Such expenditures are necessary for Aquila to maintain its standing and goodwill in the local communities; do provide benefit to the community's effort to grow; and are a customary and legitimate cost of doing business.' [FN31]

Mr. Pella testified that the fifty percent figure was used in order to avoid having to do an item by item review of each expense as the amounts in question were relatively small. [FN32]Specifically, Mr. Pella stated, 'We realized some contributions in the list could be debated more than others, which really led to the 50 percent rule to avoid sort of a line-by-line debate of value.' [FN33]

The Commission recognizes that contributions to charitable or educational institutions benefit the utility by fostering goodwill in the community and benefit the communities in which a utility provides service. However, allowing inclusion in rate base of contributions to charitable and educational institutions would be to require ratepayers to become involuntary contributors to charities, causes or institutions which they may not support. The appropriate standard for the inclusion of expenses is whether said expenses are 'prudently incurred to provide natural gas service.' [FN34] The Commission finds contributions to charitable or educational institutions should not be included as operational expenses as they do not relate to the provision of natural gas service.

Aquila has divided the membership fees and dues sought into five (5) categories: associations, trade, organizations, fraternal, and country. [FN35]In support of the amounts sought for 'organizations', Mr. Pella testified 'that it is important to be involved in local chambers of commerce because those organizations seek to grow the communities Aquila serves. This economic development and civic activity increase Aquila's customer base and load profile.' [FN36]

The Commission finds that the requested percentage of membership dues and fees which directly contribute to the growth and retention of Aquila's customer base and specifically relate to the business of providing natural gas service in Nebraska should be permitted. Those expenses which do not directly contribute to the growth and retention of Aquila's customer base are more similar to contributions to charitable, and educational institutions which foster goodwill and benefit the communities but do not directly impact the provision of natural gas service. Expenses that pertain to the operation of a natural gas utility, such as involvement in appropriate trade groups, should be included as requested.

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*7 As a matter of public policy, the Commission specifically finds that no expenses related to lobbying or legislative advocacy activity will be allowed. It is our understanding that any amounts attributable to lobbying and legislative advocacy activity have been excluded as part of the fifty percent factor adopted by Aquila.

As no evidence was offered specifically addressing each organization individually, the determination regarding inclusion of a particular expense must be based upon the limited information available in the record. In those cases in which the purpose of the entity or the nature of the fee or dues is unclear, it should be excluded. Furthermore, any fees or dues attributable to an organization outside of Nebraska should be excluded as should country club dues. Additionally, all expenses listed as 'sponsor' should also be excluded as no evidence was offered as to the nature of the sponsorship. Finally, all contributions to charitable and educational organizations must be excluded as explained previously.

Annualized Depreciation Reserves

Aquila proposed an adjustment of $3,031,242 to its depreciation expense and reserves 'to reflect the annualization of expenses based on June 30, 2006 plant balances .... The adjustment also includes updated depreciation rates resulting from a study performed by outside consultants Foster and Associates, and an adjustment for common assets that serve all utilities in the Aquila network. ' [FN37]

The Public Advocate asserts that this adjustment should be disallowed on the basis that 'This adjustment to reserves represents depreciation expense that should have been charged to ratepayers for many years. Those ratepayers were undercharged, but to go forward and collect this cost from current and future ratepayers would mismatch costs and benefits and would be a classic example of unrepresentative costs.' [FN38] In the alternative, the Public Advocate recommends that a lower adjustment be made in the amount of $2,175,184. [FN39]

In rebuttal testimony, Aquila witness Ronald White testified that the adjustment proposed by Mr. Glahn was based on the difference between the whole life rates and the remaining life rates. [FN40]Mr. White further testified that because Aquila adopted the remaining life rates, the analysis proffered by Aquila is accurate. [FN41]

The Commission finds that Aquila has properly adjusted its depreciation expense based upon the remaining lives method. Therefore this adjustment as proposed by Aquila should be included in the determination of rates.

Payroll Adjustments

a. Payroll Annualization

Aquila proposes to increase annual payroll costs by approximately $1,983,305.

The payroll annualization adjustment 'was made to annualize payroll expense to reflect changes in payroll costs through August 15, 2006 .... The annualized base pay amount was also adjusted for known vacancies and other than base payroll categories such as standby, overtime and callout pay.' [FN42] The adjustment includes all open positions for Nebraska operations, with the exception of any part-time or temporary positions. [FN43]

8 The Public Advocate contends that this adjustment should be disallowed as it includes vacant positions and should have been based on payroll costs as of the end of the test year rather than August 15, 2006.

On rebuttal, Aquila recalculated the payroll increase using actual salaries as of March 2007 data and excluding vacant positions. Based upon the recalculation, the adjustment is reduced by $373,806.00. Mr. Petersen testified that 'March 15th is the constant month in which annual merits are granted to all employees, and then the month in which the variable base pay component of the payroll increase is granted. So March is when all the payroll changes take place.' [FN44]

The Commission finds that it is proper to rely upon the actual salaries as of March 2007 as there are no matching issues related to this expense as it does not vary directly with the number of ratepayers or volumes delivered.

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Due to the fluid nature of personnel, some number of vacant positions will always exist whether attributable to staff turnover or restructuring. During the time that the positions remain vacant, a company does not incur any expenses related to salary or benefits for that person. Aquila testified that consultants or temporary personnel would be needed to fill the vacancies. However, if that were the case, those expenses should be included in the test year. The Commission finds that the portion of the adjustment related to vacant positions is not 'known and measurable' and should be disallowed. The Commission finds that the remainder of the adjustment should be permitted using the data for actual payroll recalculated by Mr. Peterson as of March 2007.

b. Variable Compensation Plan

Aquila also seeks an adjustment related to a 150 percent increase in the employee variable compensation plan which results in an increase in operating expenses of $373,806.00. [FN45]

'Aquila maintains a variable compensation or incentive pay plan for non-union employees, which is based on both the achievement of individual objectives and non-financial company objectives.' [FN46] The 'non-financial' company objectives include 'satisfactory customer service, service reliability, effective use of capital for projects, safety and to maintain or reduce Aquila's cost of service.' [FN47] In addition, to the 'non-financial' objectives, employees 'also have objectives for individual projects related to their work responsibilities.' [FN48]

Aquila did not provide any detail as to the metrics relied upon in determining whether objectives were met. Furthermore, no evidence was offered to explain the basis for the 150 percent increase in the program. Finally, no historical information was offered as to what portion of the possible incentive has been paid in the past. In rebuttal, Aquila states that the amount of variable compensation actually paid in March 2007 was $212,910.00. [FN49]

The Commission finds that consideration of the actual amount paid in March 2007 is proper under these circumstances in order to achieve the most accurate adjustment possible. No matching issues exist as the amounts do not relate to the number of ratepayers or volumes sold. Because the amount is based on actual amounts paid, it constitutes a 'known and measurable' adjustment.

*9 However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit. Therefore, the Commission finds that Aquila is entitled to an adjustment of fifty percent of the actual amount paid in March 2007 or $106,455.00. Although the Commission has no desire to micromanage the internal affairs of the jurisdictional utilities, it must have sufficient information in order to determine whether expenses are prudently incurred. Therefore, in future rate filings, applicants shall file greater detail regarding these programs as well as historical data regarding success or failure of incentive programs so as to allow the Commission to determine the prudence of the expense.

c. Economy of Scale

Aquila proposed an adjustment to reflect changes in staffing that have already occurred and will continue to occur due to the sale of Aquila's assets, such as the 'sale of Michigan, Minnesota, and Missouri gas properties, and the upcoming sale of Kansas electric properties.' [FN50]

In his direct testimony, Aquila witness Petersen explained that this adjustment reflects the 'post-sale net reductions in corporate staffing as allocated to Nebraska.' [FN51] Mr. Petersen further explains that this adjustment 'represents the value of additional reductions in the number of employees known at this time and scheduled for elimination between the end of the test year of June 30, 2006 and December 31, 2006.' [FN52] Aquila's proposed adjustment also eliminates 2005 non-incentive corporate employee bonuses that were assigned to Nebraska. The adjustment reduces base period operating expenses by $395,046, reduces taxes other

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than income taxes by $20, 110, and reduces plant in service by $47,816.

Aquila's adjustment reflects a reduction of 27 positions. Aquila's response to Public Advocate Data Request PA-77 states 'Actual support staff reductions applicable to Nebraska were a reduction of 56 positions ...' Aquila also states in this response 'no further reductions related to the reorganization of Aquila are expected during the first half of 2007.' The Public Advocate's expert, Mr, Glahn, recommends that the Commission disallow Aquila's proposed adjustment to reduce base year expenses because it was not known and measurable as evidenced by the fact that the actual staff reduction was more than double the number of positions reflected in Aquila's adjustment.

In rebuttal testimony, Aquila's expert, Mr. Petersen, provided updated payroll information that incorporated the information provided in response to Public Advocate Data Request PA-77. Mr. Petersen 'recalculated the payroll annualization with actual data available as of March 15, 2007' excluding vacant positions. [FN53]The March 15, 2007 data indicates that payroll and related benefits increased by $1,609,499 when compared to the base period actual costs.

The Commission would have expected the Public Advocate to incorporate the additional staff reductions indicated in the response to PA-77 into his recommendation rather than to simply state that the adjustment is not known and measurable because the amount initially proposed by Aquila was not totally accurate and to recommend that the adjustment be disallowed. According to Aquila's response to Public Advocate Data Request PA-77, this adjustment is known and measurable. Furthermore, a utility may propose adjustments based on the best information available at the time it prepares its rate filing and reasonably update the information through discovery.

***10** The Commission's decision on this issue is discussed below.

d. Merit Increases (Non-Union)

Aquila has proposed increases in pay for both union and non-union employees. The increases for union employees are undisputed and clearly represent 'known and measurable' adjustments based upon clearly defined contractual obligations. However, the pay increases for non-union employees are within the discretion of the company. In his rebuttal, Mr. Petersen proposes an updated adjustment which includes 'the actual March 2007 non-union employee merit increases and the union increase'. [FN54]

The Commission finds that the merit increase adjustment for non-union employees through March 2007 is 'known and measurable' and should be included.

e. Summary of Payroll Related Issues

As previously discussed, Aquila witness Petersen provided updated payroll information in his rebuttal testimony. At page 8 of his rebuttal testimony, Mr. Petersen recommended that his updated payroll adjustment be included in rates and explained that this updated amount includes Aquila's proposed economies of scale adjustment and its proposed merit pay increases for both union and non-union employees. Mr. Petersen also recommends a $207,814 increase for vacant employee positions and a $212,910 increase for variable compensation. Mr. Petersen's recommendation in his rebuttal testimony reduces Aquila's original request for these items by $531,169.

The Commission adopts Mr. Petersen's $1,609,499 increase for payroll with the exception of the adjustments described herein. The Commission rejects Aquila's proposal to include any amount in rates for vacant positions, and includes only fifty percent of the requested adjustment for variable compensation for the reasons discussed earlier.

Benefit Adjustment

Aquila seeks an adjustment of $1,498,736.00 in employee benefits which represents an anticipated increase related to health care costs. 'Aquila's medical cost increases for the five years prior to 2007 averaged under

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10 percent per year, while the national average for similar preferred provider plans was up to 8.2 percent higher.' [FN55] Aquila provides general information regarding market trends and historical data regarding past claims in support of the adjustment.

The Public Advocate contends that this adjustment is not a 'known and measurable' change and should therefore be rejected.

The Commission recognizes that health care costs continue to rise. However, the Commission finds that the 14.8 percent increase sought by Aquila is merely a projection and does not constitute a 'known and measurable' adjustment. Therefore, the Commission finds that the health care costs adjustment should not be included.

Postage Adjustment

Aquila had requested a post test year adjustment to its postage expense to reflect an anticipated $.03 increase in the postage rate. However, after the filing, the postal service's governing board approved an increase of only $.02 effective May 14, 2007. As a result, Aquila stated in its rebuttal testimony that its original adjustment should be reduced to reflect the actual postage rate increase. [FN56]The Public Advocate seeks to disallow this expense arguing that it was not a 'known and measurable' change at the time of Aquila's application. [FN57]

***11** The postage expense is a prudent cost incurred in the provision of natural gas service. Although the increase in postal rates occurred nearly a year after the end of the test year, it is a known and measurable change, affecting the revenue requirement of the utility. The original adjustment was based on the actual postage costs incurred during the test year, restated to reflect a higher postage rate. It is possible to correct the amount based upon what is now known about the postage rate based upon the information contained within the record. The adjustment as modified by the current postage rate should be permitted.

COST OF CAPITAL

'In determining a fair and reasonable return on the rate base of a jurisdictional utility, a rate-of-return percentage shall be employed that is representative of the utility's weighted average cost of capital including, but not limited to, long-term debt, preferred stock, and common equity capital. ' [FN58]

'The Commission must allow each utility a reasonable opportunity to earn a reasonable rate of return, which is expressed as a percentage of invested capital, and must fix the rate of return in accordance with *Neb. Rev. Stat.* §§ 66-1825(3) and (5).' [FN59] In evaluating each case, the Commission 'must consider the utility's cost of capital, which is the weighted average of the cost of the various classes of capital used by the utility'. [FN60]

The classes of capital include debt and equity. 'The cost of debt capital is the actual cost of debt.' [FN61] 'The cost of equity capital must be based upon a fair return on its value.' [FN62]

Cost of Equity Capital

Both Aquila and the Public Advocate develop a set of comparable companies and use financial data for those companies, combined with the discounted cash flow (DCF) model and the capital asset pricing model (CAPM), to estimate a cost of equity capital for Aquila.

Aquila proposes a sample of eight comparable companies, in part because it excludes companies with capitalizations greater than $2 billion. [FN63]Aquila provided no explanation for the $2 billion cutoff. The Public Advocate proposes a sample of 12 comparable companies [FN64] that includes Aquila's eight comparable companies plus four other companies. All four of these additional companies have market capitalizations between $2.7 and $3.4 billion. The four companies in question are classified by *Value Line* as mid-cap natural gas distribution companies. Of the eight companies proposed by Aquila, seven are also listed as mid-cap natural gas distribution companies with capitalizations ranging from $1 to $2 billion. The Commission finds no justification for excluding the four companies from the group of comparable companies because of their market capit-

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alizations.

Aquila argues that two of the four companies in question should also be excluded because of their product mixes. However, Aquila provides no data to show that either is predominantly a non-regulated company. Both are included in *Value Line* as natural gas distributors. They should be included in the group of comparable companies.

***12** Aquila generates DCF estimates in the range of 6.61 percent to 10.65 percent. [FN65]In developing these estimates, Aquila uses low and high stock prices for the past year and from a recent two-week period. Aquila also uses the 2006 dividend. [FN66]The Public Advocate develops DCF estimates in the range of 6.6 percent to 9.0 percent. [FN67]In developing these estimates, the Public Advocate uses the average of the monthly high and low stock prices over a recent three-month period and the 2007 expected dividend. [FN68]

The Public Advocate's approach for estimating the dividend yield is appropriate. The stock price information covers a period of time that is long enough to not be overly influenced by a very short-term stock. Yet it does not cover a time period so long as to no longer be relevant. In addition, using an average of the high and low stock prices washes out temporal variation that may exist in daily stock prices. In contrast, using only the high and the low stock prices over-emphasizes any temporal shocks in stock prices. The Public Advocate's use of an expected dividend is most appropriate for use in the DCF model as well. As a result, we conclude the most reasonable DCF estimates are in the range of 6.6 to 10.0 percent.

Both Aquila and the Public Advocate show concern for using equity cost estimates near the low end of the range. Given current market conditions, the Commission agrees and will focus on the upper estimate from the DCF model in determining the cost of Aquila's equity capital.

Aquila performs two CAPM analyses. [FN69]The first uses the current return on long-term government bonds as the risk free rate and the premium of common stock to long-term government bonds as the risk premium. [FN70]Aquila also applies a size premium adjustment to account for a purported bias in the CAPM that underestimates returns for small companies. [FN71]Aquila's second CAPM analysis uses the historical difference between the total market return and the long-term corporate bond return as the risk premium and uses the Aaa corporate bond rate as the risk free rate. [FN72]

The Public Advocate's CAPM analysis uses the current yield on 30-year U.S. Treasury bonds as the risk free rate and estimates the equity risk premium by subtracting the arithmetic mean of total returns on long-term government bonds from the arithmetic mean of total returns on large company stocks. [FN73]

Aquila's analysis that uses the historical return on corporate bonds as the risk free rate is a non-standard approach. Even high grade corporate bonds carry more risk than U.S. government bonds. One could reasonably expect any CAPM estimate using a corporate bond rate as the risk free rate to be higher than estimates using U.S. Treasury securities and Dr. Murry's results bear this out. This approach produces results that are clearly beyond the threshold of a reasonable range of allowable returns on equity in this matter.

Aquila's inclusion of a size adjustment in the CAPM model is unwarranted. The market factors that allow the universe of all small- and medium-cap privately held companies to over-perform their CAPM equity return predictions may or may not exist for the relatively small and unique set of regulated natural gas distribution companies. Until research becomes available establishing such a relationship, this size adjustment overstates the expected equity earnings for a regulated natural gas utility.

***13** The record provides enough information to perform a CAPM analysis on the return on equity for the sample of 12 comparable companies using both Aquila's and the Public Advocate's preferred risk free rates and risk premia. The CAPM-generated returns on equity range between 10.4 and 11.26 percent, with the average of 10.8 percent.

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Based on DCF and CAPM analysis, the Commission finds that a rate of return on equity capital of 10.4 percent is reasonable.

Cost of Debt

Aquila proposes a weighted average cost of long-term debt equal to 7.13 percent. [FN74]The Public Advocate takes exception with the re-pricing of the 11.875 percent series used to calculate that weighted average cost of debt, arguing that it should be re-priced assuming an investment grade of BBB+. [FN75]This argument is unconvincing. Mr. Glahn's *Schedule 8* filed with his prefiled direct testimony shows that four of the twelve companies in his comparison group have an S&P credit rating below BBB+. Two have a credit rating of BBB-. Southern Union, with an equity ratio of 50 percent has a BBB- rating. The Commission finds that a cost of debt equal to 7.13 percent should be used.

Capital Structure

Aquila proposes a capital structure of 51 percent equity and 49 percent debt. [FN76]The Public Advocate does not propose an alternate equity ratio. The Commission finds that an equity ratio of 51 percent is reasonable for Aquila Networks.

Overall Cost of Capital

The Commission concludes that Aquila Networks - Nebraska should be allowed a cost of equity equal to 10.4 percent, a cost of debt equal to 7.13 percent and a common equity ratio of 51 percent. This results in an overall cost of capital equal to 8.8 percent.

RATE MECHANISMS

Aquila has proposed three (3) automatic rate mechanisms: a weather normalization adjustment (WNA), a revenue normalization adjustment (RNA) and a limited cost recovery adjustment (LCR).

The WNA is an adjustment intended to account for variations in weather conditions so as to avoid spikes in utility revenue during colder periods and significant decreases in revenue during warmer weather.

'The RNA Rider is a billing adjustment factor computed on a monthly basis that creates a credit or charge to the monthly delivery charge for firm customers ...designed to stabilize the level of revenues that are provided by customers to the Company each month.' [FN77] In essence, the RNA is intended to address declining revenues related to decreases in declining usage.

The LCR is an adjustment for inflation which allows Aquila to increase rates based upon increases in the consumer price index.

Automatic rate mechanisms raise concerns of piecemeal rate making by adjusting for only one element of cost without accounting for other increases and decreases in costs incurred by the utility. Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operate efficiently. Therefore, their use should be limited.

***14** Rate regulation under the State Natural Gas Regulation Act is relatively recent. Similarly, the move toward such automatic adjustments as proposed by Aquila is also fairly new. The Commission does not wish to dissuade utilities from seeking innovative approaches to rate making in Nebraska to ensure safe and affordable natural gas service for ratepayers. However, at this stage of natural gas rate regulation in Nebraska, the future impact of those mechanisms on ratepayers is difficult to ascertain. Therefore, the Commission finds that the rate mechanisms should be denied.

ENERGY EFFICIENCY RIDER

Aquila seeks a $0.0070 per therm surcharge listed as a separate line item on ratepayer's billing statements used to recover the costs of Aquila's energy efficiency and low income weatherization support program. The Public Advocate did not object to Aquila's proposal.

The Commission finds that the surcharge should be ap-

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proved; however, we will require that Aquila true-up the actual amounts paid in the program and report the amounts attributable to the administrative program each six months.

RATE DESIGN

Traditional vs. Alternative Rate Design

Both Aquila [FN78] and the Public Advocate [FN79] recommend continuing the traditional rate design contained in current rates. A traditional rate design includes two components: (1) A fixed monthly charge, or customer charge, that does not vary with the level of usage, and (2) a commodity charge, or delivery charge, per Therm that does vary with the level of usage. The sum of the customer charge and delivery charge are commonly referred to as the base rates. In addition to the base rates, a customer will be charged a Purchased Gas Cost Adjustment (PGA) charge for the cost of gas and other non-base rate charges such as franchise fees, regulatory assessments and taxes. The base rates are the charges that are to be determined in this proceeding.

Aquila's recommendation to continue using a traditional rate design is conditioned on the Commission also approving the Company's proposed RNA and WNA. In the alternative, Aquila is proposing two alternative rate designs. [FN80]Under rate design Alternative 1, Aquila would only increase the customer charge with the approved revenue increase. In other words, the Company would leave the commodity or delivery charges at current rate levels and use the entire amount of any approved revenue increase to increase the monthly customer charge. Under rate design Alternative 2, Aquila proposes to eliminate the commodity or delivery charge and recover all base rate revenues in the customer charge. This would result in a large, flat monthly charge for all customers in each customer class.

Aquila's rate design Alternative 1 has several problems that do not make it an acceptable rate design. First, as acknowledged by Aquila, [FN81] this alternative does not recognize the variance in costs to serve different sizes of customers that require varied capacity on the system. Under rate design Alternative 1, it is likely that large customers within a customer class will underpay their cost of service while small customers will overpay. In addition to this problem under rate design Alternative 1, small or low use customers will receive a significant percent rate increase while medium and large customers would pay less than current rate charges. [FN82]Because of these disparate customer impacts in each customer class, it would not be reasonable to adopt rate design Alternative 1, even if other factors supported its approval.

***15** Aquila's rate design Alternative 2 has the same problems related to Alternative 1, only on a more magnified level. [FN83]In addition, the flat customer charge only rate design would decrease price incentives for customers to improve energy efficiency. The customer would pay the same base rate charge regardless of how much the customer can reduce its energy needs through energy conservation.

For the reasons discussed, the approved rates should be based upon a traditional rate design. Accordingly, Aquila's proposed rate design Alternatives 1 and 2 should be rejected.

Consolidated Rate Area Rates

In the past, Aquila has had separate base rates for Rate Areas 1, 2 and 3. The three rate areas were established under the prior regulatory structure whereas the municipals within each rate area regulated the natural gas rates. In this case, Aquila is proposing to consolidate the rates in each rate area into a Nebraska-wide or consolidated rate. [FN84]The primary reason for consolidating the different rate area rates is that the cost of service and current rates of each rate area are not that different. The Public Advocate concurs that rate areas should be consolidated. [FN85]

The reasons submitted by Aquila support consolidating the rates in each rate area into a Nebraska-wide rate. In addition, a consolidated rate will reduce administrative and regulatory expenses. The Company's proposal to consolidate the rate area rates into on Nebraska-wide

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rate is approved.

Customer Charge Level

Under the traditional rate design, Aquila is proposing to significantly increase the fixed monthly customer charge for both the residential and commercial customer classes. As explained by Aquila witness Thomas Sullivan, the large increases are intended to recover more of the fixed customer-related costs in the customer charge rather than in the volume-related or variable commodity charge (delivery charge). [FN86] The table below summarizes Aquila's proposal regarding customer charges: [FN87]

Customer Class	Current Customer Charges	Proposed Customer Charges	Aquila Proposed Monthly Increase Amount	Percent
Residential	$11.00	$16.00	$5.00	45.5%
Commerical	$15.00	$20.00	$5.00	33.3%

The Public Advocate disagrees with Aquila on the amount of costs classified as customer-related. While the Public Advocate believes that the customer charge should increase by a greater percent than the commodity or delivery charge, [FN88] the Public Advocate is recommending a much smaller increase in the monthly customer charges.

The record supports an increase in the monthly customer charges, however, the level of Aquila's recommended increase is too large. Additionally, Aquila's proposed shift of additional costs is based upon a rate design established during the utility's last rate case. The outcome of that case was a generic or 'black box' settlement. Although the Commission found the rates in the prior case to be just and reasonable, the issue of rate design was not litigated.

***16** The Commission recognizes the benefits of sending proper price signals to ratepayers in order to encourage conservation. We also recognize that nationally some states have chosen to move a greater portion of fixed costs from the volumetric charge to the fixed charge. Utilities have argued that such reallocation of costs between the fixed and volumetric charges will eliminate the utility's disincentive to encourage conservation.

Additionally, proper price signals are necessary to encourage efficiency in the provision of natural gas service. In determining fair and reasonable rates, the Commission must strike the appropriate balance between ensuring that the utility has a reasonable opportunity to earn a fair rate of return and protecting ratepayers from unreasonable impacts of dramatic increases in fixed rates. We are not convinced that a substantial increase in the customer charge strikes that balance.

Therefore, the Commission finds that the approved customer charges are $12.00 per month for the residential class and $17.00 per month for the commercial class. The balance on the revenues assigned to each customer class should be recovered in the commodity or delivery charge resulting in a rate of $0.15406 for residential customers and $0.17561 for commercial customers. The Commission will continue to be open to innovations in rate design that are in the best interest of ratepayers.

ALLOCATED COST OF SERVICE

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The allocated cost of serving each customer class is usually the primary factor to consider in setting revenue levels by customer class. Other factors may be considered as well which could result in customer class revenue levels above or below the class' allocated cost of service. [FN89]The customer class allocated cost of service study is also used to allocate cost between Aquila's unregulated or large volume customers and the regulated (residential and commercial) customers.

Cost of service studies can be developed using a variety of methodologies and require some subjectivity by the ratemaker. Since the cost of service study is the primary consideration in determining customer class revenue levels and rate levels, it is important that the cost of service study be as accurate as possible. Aquila witness Thomas Sullivan presented the Company's proposed cost of service study. Albert Bartsch and Kimberly Lillyblad presented a differing view of the appropriate class allocated cost of service study on behalf of the Public Advocate.

Direct Assignments to Large Volume Customers

Rates and service rules for Aquila's large volume or industrial customers continue to be unregulated, i.e., similar to the regulatory structure when municipals regulated rates in each rate area. While the Commission does not set rates for Aquila's large volume customers, the Commission can determine the appropriate allocation of costs to the large volume customer class. This allocation of costs between Aquila's large volume customer and all other customers is the jurisdictional allocation that determines the level of rates from the customer classes that the Commission does have jurisdiction over.

***17** A major issue in determining this jurisdictional allocation, or split, was the direct assignment of the cost of mains to certain large volume customers and to the existing rate areas. Aquila argued that it has traditionally directly assigned the costs of specific mains used to serve specific rate areas and industrial customers to those areas and customers. In addition, those industrial customers receiving service from directly assigned mains were not further allocated the costs of mains used to provide services to all other customers.

The Public Advocate stated that no mains should be directly assigned. Instead the cost of all mains should be allocated to the customer classes based on allocation factors. [FN90]Mr. Bartsch claims that allocating all costs, instead of directly assigning costs specifically used to serve certain rate areas and customers, is both 'much simpler' and also more accurate. [FN91]In addition, the Public Advocate witness claims to have based the Public Advocate's cost allocation study using the criteria established in NARUC's Gas Distribution Rate Design Manual. [FN92]

The primary difference between the utility and the Public Advocate is the allocation of transmission mains (Account No. 367) and of distribution mains (Account No. 376). Aquila directly assigns the cost of mains to specific rate areas or customers, or groups of customers, when the data is available, and then allocates the remaining cost of mains to all other customers. The Public Advocate does not directly assign any costs and allocates all costs based on allocation factors.

In general, the Commission believes that the direct assignment of costs to customers or customer classes will result in a more accurate cost of service study if adequate accounting information is available to support the direct assignments. Despite the Public Advocate's claim that it based their cost of service study on the principles included in the NARUC Gas Distribution Rate Design Manual, the Public Advocate did not seem to follow this manual with regard to direct assignments. On page 20 of that NARUC manual, the guidance on direct assignments is as follows:
All items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers.

Accordingly, in this proceeding, the Commission accepts Aquila's direct assignment and allocation of mains. However, the Commission believes this is a significant issue that did not receive adequate attention in this case. We, therefore, direct the parties to further de-

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velop and analyze the benefits and risks of this issue in Aquila's future rate case. In addition, Aquila should address in its next rate case filing the reasons that a consolidated (Rate Area 1 though 4) cost of service study is not preferable to its Rate Area specific cost allocation methodology.

***18** *Account Nos. 381 through 385 Weighting Factors*

The other major cost allocation issue is the appropriate weighting factors to be used in developing allocation factors for use in allocating plant costs booked to Account Nos. 381 through 385. As listed in the FERC uniform System of Accounts, these accounts are identified as follows: [FN93]

Account Number	Description
Account No. 381	Meters
Account No. 382	Meter Installations
Account No. 383	House Regulators
Account No. 384	House Regulator Installations
Account No. 385	Industrial Measuring & Regulating Station Equipment

Weighting factors are applied to the number of customers in each customer class to reflect the difference in costs per customer for the equipment costs. For example, meters for residential customers cost less than meters for large commercial customers. Accordingly, commercial customers have a higher weighting factor when developing the allocation factor for meter related costs.

Aquila presented a Weighting Factor Study that the Company had prepared in support of its proposed weighting factors. [FN94]Aquila used its plant accounting data to develop the weighting factors. The Public Advocate accepted Aquila's weighting factors for Account Nos. 381 through 384 but directly assigned all of Account No. 385 costs to the large volume or unregulated customers. Ms. Lillyblad explained in her direct testimony that she directly assigned Account No. 385 costs to the large volume customers based upon the FERC definition of costs to be included in Account No. 385. [FN95]On rebuttal, Mr. Sullivan explained that metering and regulating equipment costs booked to Account No. 385 serve both large regulated and unregulated customers. [FN96]

The analysis and information provided supports adoption of Aquila's allocation of costs in Account Nos. 381 through 385 and of Aquila's weighting factors.

Other Cost Allocation Issues

The two most significant cost allocation issues are those previously discussed and decided. In Aquila's Post Hearing Brief, several other differences in allocations between the utility's and the Public Advocate's cost of service studies are listed. [FN97]These other cost allocation issues include:

1. Application of correct weighting factors to Account No. 380,

2. Allocate Account No. 387 based on the customer accounts weighting factor,

3. Allocate Account No. 874 based on the combined mains and services plant accounts,

4. Allocate Account No. 892 based on the services plant account,

5. Exclude the acquisition adjustment balance from the

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determination of net plant, and

6. Allocate depreciation reserves and depreciation expenses for the acquisition adjustment on the corrected net plant allocator rather than on general plant.

In the rebuttal testimony of Thomas Sullivan, these other cost allocation issues are discussed. [FN98]There is not any specific support in the Public Advocate's direct testimony for these other cost allocation issues. At the hearing, Mr. Bartsch agrees with using the Aquila's weighting factors for Account No. 380. [FN99]For the remaining other cost allocation issues, the only evidence in the record on these issues supports Aquila's position. For purposes of this proceeding, therefore, the Commission accepts the Company's methodology on these other cost allocation issues.

Jurisdictional Cost Separation

***19** As previously mentioned, the allocated cost of service study is used for both allocations to jurisdictions and to customer classes. Since the Commission has not changed Aquila's allocation methodologies for purposes of jurisdictional allocations, Aquila's assignment of costs to the Nebraska regulated jurisdiction prior to any jurisdictional revenue requirement adjustments is approved. However, we do agree with the Public Advocate that the allocation model used by Aquila to determine the jurisdictional allocations and test year adjustments can be improved. In the next Aquila rate case, we order that the rate filing schedules used to determine the utility's revenue requirement include both total Nebraska amounts and the Commission's jurisdictional amount. Any test year adjustment should also be made to the total Nebraska amounts as well as to the jurisdictional amounts.

Revenue Distribution

While the allocated cost of service study is the primary factor to be considered in distributing the proposed revenue increase among the customer classes, other factors should also be considered. [FN100]As explained by Mr. Bartsch, some of these other factors include: rate stability, customer impacts, energy efficiency incentives, ease of understanding, and gradualism. [FN101]In order to temper the rate impacts on certain customers or customer classes, it is common to gradually move to cost-based rates rather than move completely in one rate case. This concept or factor is commonly referred to as gradualism. Gradualism is also supported by the NARUC Gas Distribution Rate Design Manual.

Aquila has not applied gradualism and instead is proposing to set customer class revenue levels equal to their allocated cost of service. The result is widely varying rate increase levels as shown on Aquila's rate filing Exhibit TJS-9, page 2, column (x). As shown on this exhibit, the cost-based rates would result in substantial percent increases in base rates for residential customers while the commercial and Energy Options customers would receive substantial rate reductions. This outcome is inappropriate.

The Public Advocate's recommended gradualism constraint is to limit the percent increase to the residential class to 1% above the total average percent increase for all customers. [FN102]We accept the PA's gradualism recommendation. Based upon the Commission's approved total revenue increase, this would result in the following rate increases for each of the customer classes:

Customer Class	Current Rate Revenues	Approved Rate Revenues	Approved Increase
Residential	$37,101,291	$44,175,730	$7,074,439
Commercial	$9,506,174	$10,961,992	$1,455,818

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			624,525
Energy Options	$4,0.66,825	$4,691,351	
Total	$50,674,291	$59,829,072	9,154,782

COMPLIANCE

The Commission finds that a compliance conference should be scheduled by the hearing officer to allow all parties an opportunity to discuss the terms and practical effects of the order. Subsequent to the conference, Aquila shall submit to the Commission a Compliance Filing which shall include at least the following information.

Interim Rate Refund Plan

***20** As permitted by law, Aquila implemented interim rates pending the consideration of its rate application. [FN103]Aquila chose to implement the full amount of its proposed rate. As a result of the Commission's decision herein, ratepayers are entitled to a refund of any amounts paid over and above the rates approved herein.

The Commission recognizes that companies may implement interim rates in a variety of appropriate ways. The method for calculating refunds must be consistent with the manner in which the interim rate was implemented. Aquila will be required to file a Refund Plan within 30 days from the compliance conference referenced herein. That Refund Plan will include a proposal for refunding the differences between the interim rate revenue collected and its final rates. The Commission reserves the ability to receive evidence regarding such Refund Plan and to enter a subsequent order regarding such Refund Plan as hereafter provided in this order.

Energy Efficiency Rider

Consistent with the terms herein, Aquila shall file with the Commission information each six months regarding the amount of rebates given and low-income weatherization provided as well as the administrative costs for the programs.

Tariff Sheets

Finally, within thirty (30) days of the compliance conference, Aquila shall file any necessary tariff sheets with the Commission.

ORDER

IT IS THEREFORE ORDERED by the Nebraska Public Service Commission that Aquila's application is approved in part and denied in part as set forth specifically herein.

IT IS FURTHER ORDERED that Aquila has a revenue requirement of $59,829,072.00, representing an increase of $9,154,782.00.

IT IS FINALLY ORDERED that Aquila shall make a compliance filing consistent with the findings herein within thirty days of the compliance conference to be scheduled by the hearing officer.

MADE AND ENTERED at Lincoln, Nebraska this 24th day of July, 2007. Signature Executive Director

FOOTNOTES

FN1 The current residential volumetric charges for each rate area are as follows: Rate Area One (Near Omaha) = $0.10967 per therm; Rate Area Two (Lincoln) = $0.11070 per therm; and Rate Area Three (Rural Eastern Nebraska) = $0.12177 per therm.

FN2 The current business volumetric charges

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for each rate area are as follows: Rate Area One (Near Omaha) = $0.12700 per therm; Rate Area Two (Lincoln) = $0.15922 per therm; and Rate Area Three (Rural Eastern Nebraska) = $0.15266 per therm.

FN3 *Neb. Rev. Stat.* § 66-1825(1) (2003).

FN4 § 66-1825(3).

FN5 § 66-1825(4).

FN6 § 66-1825(6).

FN7 Neb. Admin. Code, Title 291, Ch. 9 § 005.06D (2006).

FN8 § 005.06F.

FN9 § 005.06D.

FN10 Rebuttal Testimony of Vern Siemek, 2:20-22.

FN11 Siemek Rebuttal, 2:27-28.

FN12 Testimony of William Glahn, 31:21-32:2.

FN13 Glahn, 32:2-5.

FN14 Direct Testimony of Vern Siemek, 20:19 - 23:14.

FN15 Siemek, 21:3-5.

FN16 Siemek, 21:18-21.

FN17 Direct Testimony of Albert Bartsch, 5:20.

FN18 Bartsch, 5:16-17.

FN19 Bartsch, 5:12.

FN20 § 005.06D

FN21 Bartsch, 6:8-11.

FN22 Bartsch, 6:4-7.

FN23 Bartsch, 6:13-14.

FN24 See Transcript, 112:3-18.

FN25 § 005.06B.

FN26 § 005.06B3.

FN27 Glahn, 40.

FN28 Exhibit WLG-15, p. 4 of 5.

FN29 § 66-1825(7) (emphasis added).

FN30 § 004. 01B(4).

FN31 Rebuttal Testimony of Steve Pella, 3:1-6.

FN32 Pella Rebuttal, 3:13-18.

FN33 Tr., 30:4-7.

FN34 § 66-1825(7).

FN35 Pella Rebuttal, 5:16-18.

FN36 Pella Rebuttal, 6:17.

FN37 Direct Testimony of Richard Petersen, 6:14-22.

FN38 Glahn, 33:5-9.

FN39 Glahn, 33:9-10.

FN40 Rebuttal Testimony of Ronald White, 3:17-4:10; 5:1-6:5.

FN41 White Rebuttal, 6:7-20.

FN42 Petersen, 7:3-4; 7:7-9.

FN43 See Petersen, 7:12-18.

FN44 Tr., 81:9-13.

FN45 Aquila Application

FN46 Petersen, 8:20-22.

FN47 Petersen, 9:7-9.

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FN48 Petersen, 9:10-11.

FN49 Rebuttal Testimony of Richard Petersen, 7:4-6.

FN50 Petersen, 10:9.

FN51 Petersen, 10:19.

FN52 Petersen, 14:5.

FN53 Petersen Rebuttal, 3:10.

FN54 Petersen Rebuttal, 9:4-7.

FN55 Direct Testimony of Ruth Gustin, 4:12-14.

FN56 Petersen Rebuttal, 11:13-17.

FN57 Glahn, 37:16-38:5.

FN58 § 66-1825(5).

FN59 § 005.05A.

FN60 § 005.05A2.

FN61 § 005.05A2(a).

FN62 § 005.05A2(b).

FN63 Direct Testimony of Dr. Don Murry, 11:11-12 and 12:11-14.

FN64 Glahn, 12:6-24; 13:10-17.

FN65 See Aquila Exhibits DAM-17 - DAM-22.

FN66 See Murry, 23.

FN67 Glahn, 19:12-26.

FN68 Glahn, 16:12-17.

FN69 Murry, 33:14-17.

FN70 Id.

FN71 Murry, 33:17-20.

FN72 Murry, 33:16-17.

FN73 Glahn, 20:12-21:8.

FN74 Murry, 15:1-2.

FN75 Glahn, 28:3-29:2.

FN76 Murry, 12:16-20.

FN77 Direct Testimony of Paul Raab, 22:3-8.

FN78 Direct Testimony of Thomas Sullivan, 20:1 - 24:6.

FN79 Bartsch, 14:1 - 15:11.

FN80 Sullivan, 25:1 - 31:20.

FN81 Sullivan, 30:11 - 14.

FN82 Aquila's Exhibit TJS-9 and Exhibit TJS- 10.

FN83 Sullivan, 31:3-7, Aquila's Exhibit TJS-9 and Exhibit TJS-10

FN84 Sullivan, 22:3 - 13.

FN85 Bartsch, 11:1-21.

FN86 Sullivan, 21:10 - 22:2.

FN87 Aquila's Exhibit TJS-7.

FN88 Bartsch, 14:21 - 23.

FN89 Bartsch, 14:3 - 23.

FN90 Bartsch, 10:16.

FN91 Bartsch, 11:10 - 21.

FN92 Bartsch, 10:12 - 13.

FN93 Rebuttal Testimony of Thomas Sullivan, 24:4 - 16.

FN94 Aquila Rebuttal Testimony Exhibit TJS- 6.

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FN95 Direct Testimony of Kimberly Lillyblad

FN96 Sullivan Rebuttal, 26:14 - 31:22.

FN97 Post Hearing Brief of Aquila, at 108.

FN98 See Sullivan Rebuttal.

FN99 Tr., 239:15 - 240:2.

FN100 Bartsch, 13:1 - 14:23.

FN101 Id.

FN102 Direct Testimony of Albert Bartsch, 14:15 - 23.

FN103 'If the rate filing is not certified by the commission for negotiations, the jurisdictional utility's filed rates may be placed into effect as interim rates, subject to refund, upon the adoption of final rates, ninety days after filing with the commission.' *Neb. Rev. Stat.* § 66-1838(10)(b) (2003).

END OF DOCUMENT

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