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BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

In the Matter of the Petition of	)	
Chattanooga Gas Company for a	)	
General Rate Increase, Implementation	)	DOCKET NO. 09-00183
of the EnergySMART Conservation	)	
Programs and Implementation of a	)	
Revenue Decoupling Mechanism	)	

PRE-FILED DIRECT TESTIMONY AND EXHIBITS OF

DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE TENNESSEE ATTORNEY GENERAL
CONSUMER ADVOCATE & PROTECTION DIVISION

March 10, 2010

DIRECT TESTIMONY OF
DAVID E. DISMUKES, PH.D.

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana with additional staff in Los Angeles, California, and Fallon, Nevada.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also an Adjunct Professor in the E.J. Ourso College of Business Administration (Department of Economics), and I am a full member of the graduate research faculty at LSU.

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing of my publications, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. I have prepared 22 exhibits in support of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Tennessee Attorney General, Consumer Advocate and Protection Division ("Consumer Advocate") to provide an expert opinion on the Chattanooga Gas Company's ("CGC" or "Company") proposed energy efficiency program, called "energySMART," and its proposed Alignment and Usage Adjustment mechanism ("AUA" or "revenue decoupling tracker"), filed before the Tennessee Regulatory Authority ("TRA") on November 16, 2009. I have also been asked to opine on the Company's bare steel replacement program and its relationship to the revenue decoupling tracker proposed in this proceeding.

As part of my testimony I will address the general issues of: (1) what is the appropriate mechanism, or financial incentive, to insure that CGC's financial incentives are aligned with the state's energy conservation policy; and (2) if CGC should be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations

- Section III: Proposed Energy Efficiency Program
- Section IV: Proposed Decoupling Tracker
- Section V: Inconsistency of Decoupling with Economic Thought and Regulatory Practice
- Section VI: Deficiencies in the Rationale for Decoupling
- Section VII: State Regulatory Policies and Decoupling
- Section VIII: Decoupling and Risk Shifting
- Section IX: Implementation Deficiencies in the Decoupling Tracker
- Section X: Policy Alternatives: Lost Base Revenues
- Section XI: Policy Alternatives: Modified Revenue Decoupling
- Section XII: Policy Alternatives: Ratepayer Protections
- Section XIII: Infrastructure Replacement and Decoupling
- Section XIV: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR REVENUE DECOUPLING RECCOMMENDATIONS?

A. I recommend that the TRA reject the Company's proposed AUA, or revenue decoupling tracker mechanism for the following reasons:

- Revenue decoupling is not needed in order for regulatory policy to be consistent with federal and Tennessee energy legislation. This point has already been clearly articulated by the TRA in the Piedmont case[1], and no

[1] See In Re: Petition of Piedmont Natural Gas, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs, TRA Docket No. 09-00104. Petition filed July 16, 2009.

evidence has been provided in this proceeding that would justify a deviation from that precedent.

- The Company's revenue decoupling tracker is entirely inconsistent with traditional regulation and, like most tracker mechanisms, would lead to a number of disincentives for cost efficiency and risk management. The disincentive for cost efficiency created by revenue decoupling has been recognized twice by the TRA. I recommend the TRA continue to uphold this precedent in the instant proceeding.
- The Company's revenue decoupling tracker would transfer a considerable amount of sales risk away from shareholders and towards ratepayers with virtually no reciprocal, or proportional, benefits.
- The Company's proposed revenue decoupling tracker includes no ratepayer protection mechanisms.
- The Company has not shown that its proposed energy efficiency programs would create any form of financial harm.
- The scale and scope of the Company's proposed energy efficiency program does not rise to the level where a revenue decoupling mechanism is needed. The annual lost base revenues resulting from the Company's proposed energy efficiency measures, conservatively, are estimated to be only $202,355 over the first five years of the program.
- Any potential negative financial impacts resulting from these limited energy efficiency programs, to the extent they occur, could easily be accommodated within a lost base revenues mechanism.

Q. DO YOU HAVE ANY RECOMMENDATIONS ABOUT THE COMPANY'S ATTEMPT TO TIE REVENUE DECOUPLING TO INFRASTRUCTURE REPLACEMENT?

A. I recommend that the TRA reject the Company's assertion that the adoption of revenue decoupling will be supportive, or should be used as supportive, of infrastructure replacement activities. Revenue decoupling, to the extent it is adopted, should be used exclusively to support energy efficiency activities, not infrastructure replacement or other revenue stabilization, or revenue enhancement measures. Further, the Company has not provided any effective evidence that: (1) shows currently-proposed rates are deficient in supporting its future investments; and (2) that there is a need for accelerating replacement activities beyond what is already included in the Company's proposed rates.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED ENERGY EFFICIENCY PLAN?

A. Yes. The cost effectiveness plan supporting the Company's energy efficiency program includes a number of mechanical errors, input errors, and faulty assumptions that yield unreliable results. I recommend that the TRA reject the Company's cost effectiveness analysis, and utilize the alternative analysis I have provided that shows a very limited amount of cost-effective energy efficiency savings that will be offered in return for a very large change in the way the Company is regulated. The Company's energy efficiency plan also lacks any independent monitoring and verification and should be rejected until such a plan can be presented for the TRA's consideration. Lastly, the TRA should also reject the Company's proposed Education and Outreach program since it is lacking in detail, a formalized plan, goals and independent oversight.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes. If the TRA would like to actively promote energy efficiency, I recommend that a performance-based mechanism that rewards CGC for greater-than-average success at achieving its energy efficiency potentials be adopted. No performance-based approach should be adopted until the Company submits, for approval, a monitoring and verification plan for its energy efficiency program.

Q. DO YOU HAVE ANY RECOMMENDATIONS IN THE EVENT THAT THE TRA DECIDES TO ADOPT REVENUE DECOUPLING?

A. Yes. If the TRA accepts the Company's decoupling proposal, I recommend the following modifications to the mechanism:

- Include an ROE adjustment as recommended by Dr. Christopher Klein.
- Reject the Company's proposal to allow revenue recovery amounts to increase with customer growth.
- Include a consumer protection mechanism that would restrict decoupling revenue recovery amounts to either:
    - A level no greater than the annual capacity and throughput cost savings from the purchased gas acquisition ("PGA") clause. ("New Jersey Approach")
    - A amount that does not exceed 24% percent, and decreases relative to shortfalls in reaching target energy efficiency savings.

("Washington Approach").

- If the TRA opts to not use a threshold percent, then include an additional consumer protection measure that restricts revenue decoupling accruals to no more than 2.0 percent of total revenues.
- Require a review of the decoupling mechanism in no more than three years. The Company's decoupling mechanism should be evaluated against strong energy efficiency performance goals. These goals should be based on the Company's performance in meeting its savings targets estimated for its proposed energy efficiency programs. This review should include a regulatory presumption that the decoupling mechanism will be repealed in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.
- Define criteria for the decoupling review that would include: (1) an energy efficiency review; (2) a revenue deferrals and collections review; (3) a customer usage analysis; and (4) other mutually acceptable review criteria that are defined by the TRA, the Company, and other stakeholders such as the Consumer Advocate.
- The Company should make annual compliance filings with the Authority that identifies and compares estimated and actual costs incurred for each program, the estimated and actual number of participants for each program, and the estimated and actual therm savings for each program. A complete listing, and cost itemization for the Company's market

transformation (education) activities should also be provided as well as annual collections, and running net balances for collections made under the decoupling tracker.

- The Company should be held to performance metrics on program costs and savings.

III. PROPOSED ENERGY EFFICIENCY PROGRAM

Q. WOULD YOU BRIEFLY DESCRIBE THE COMPANY'S PROPOSED ENERGY EFFICIENCY PROGRAMS?

A. Yes. The Company is proposing a two-fold energy efficiency program, which it refers to as its "energySMART" program. The first component of this program consists of a customer education and outreach program, while the second component consists of a variety of residential and commercial energy efficiency measures. The break down of the program components, and their respective costs, has been provided in Exhibit DED-1. The education and outreach component comprises 34 percent of total program costs, the residential efficiency component of the program comprises 50 percent of the total costs, and the commercial energy efficiency measures comprise 16 percent of the total costs. Administrative and marketing costs associated with the program are purportedly included in the Company's education and outreach costs.

Q. HOW DO THE RELATIVE COSTS, AND PROGRAM COST SHARES, COMPARE TO OTHER NATURAL GAS UTILITY ENERGY EFFICIENCY PROGRAMS?

A. The allocation of costs among program components is not consistent with other leading natural gas utility energy efficiency programs across the U.S. The Company is proposing to spend a considerably larger share on education and outreach than is common for programs of this nature. The Company proposes to spend over 30 percent on education and outreach efforts, which is significantly greater than the typical average of nine percent.[2]

Q. HOW DO THE COMPANY'S PROPOSED ENERGY SAVINGS COMPARE TO OTHER LDC ENERGY EFFICIENCY PROGRAMS?

A. Total measure efficiency savings are low compared to other LDCs. The Company's total program savings are 0.2 percent of total retail sales (including gas) compared to 0.5 percent of total retail sales average reported by other LDCs considered leaders in the development of energy efficiency programs. A comparison between the Company and these LDCs has been provided in Exhibit DED-2.

Q. CAN YOU PLEASE DESCRIBE THE EDUCATION AND OUTREACH COMPONENT OF THE COMPANY'S ENERGY EFFICIENCYPROGRAM?

A. Yes. The Company is proposing to implement a customer education program, commonly referred to as "market transformation" programs, designed to educate customers about efficiency and conservation through bill inserts, print advertisements, and radio and/or other media.[3] The program has also been designed to purportedly provide information on the Company's energySmart programs. The Company's education and outreach program supposedly will

[2] American Gas Association. Natural Gas Efficiency Programs Report, 2008 Programs Year. December 2009.

[3] Response to CAPD Question 171.

include information and training for businesses and vendors participating or supporting the Company's energySmart programs. These businesses include heating, ventilation, and air conditioning ("HVAC") contractors, plumbers, appliance dealers, and CGC's own customer service representatives.[4]

Q. HOW MUCH DOES THE COMPANY PROPOSE TO SPEND ON ITS ENERGY EDUCATION EFFORTS?

A. As depicted on Exhibit DED-1, the Company estimates that it will spend $300,000 on administration, education and outreach efforts in the first year of the program. These expenditures are forecast to decrease by $50,000 after the first year and $25,000 each year after following program implementation. The Company is also proposing to share in the costs of its market transformation programs. In the first year, the Company is proposing to cover about a third of all education and outreach expenditures ($100,000 out of $300,000) below the line. The Company will reduce that contribution in the second year to about one-fifth ($50,000 out of $250,000), and down to 11 percent ($25,000 out of $225,000) in the third year of the program. The Company will make no contributions in the last year of the program. In total, the Company proposes to contribute $175,000 to a total of $975,000 (about 18 percent) of all energy efficiency education expenditures. The Company has noted that during the course of the program, it will not seek rate recovery for any of its contributions.[5]

Q. ARE ADMINISTRATIVE AND MARKETING COSTS INCLUDED IN THE COMPANY'S EDUCATION AND OUTREACH BUDGET?

[4] Direct Testimony of Donna Peeples, pp. 7-9.
[5] Direct Testimony of Steve Lindsey, p. 12.

A. Yes, it would appear that way. Administrative costs are included in the line for education and outreach as identified in Exhibit DJN-1.[6] The inclusion of these costs in the education and outreach budget raises a number of ratemaking issues since none of these costs have been clearly itemized or identified. For instance, the Company was able to provide a two-page budget related to many of its anticipated education and outreach costs including: radio, print, and online advertising; community outreach workshops; and exhibits. This budget has been reproduced in Exhibit DED-3. The budget also includes the costs of other presumably important educational items such as wallet cards; door hangers; and lapel buttons. However, the only line items that pertain to program administrative costs appears to be the publication costs associated with literature promoting the energySMART programs. There are no other program administrative costs itemized in this budget.[7]

Q. ARE THERE ANY PLANS, GOALS, OR EDUCATIONAL TARGETS INCLUDED IN THE COMPANY'S PLANS?

A. No. The budget itemizes a number of expenditures and shows a timeline, but there is no educational plan describing governing educational philosophies, goals, or oversight, monitoring, nor accountability measures.[8] The educational plan has no site locations or preliminary lists, as to how such programs or vendor training will occur. There are no performance metrics. The Company's budget is a generalized marketing list of items that it would like to fund with ratepayer resources. As such, the program should be rejected in its current form.

[6] As updated by Response to CAPD Question 151, Attachment 151-2.
[7] Response to CAPD Question 171.
[8] Response to CAPD Question 176.

Q. DO THE COMPANY'S PROPOSALS REGARDING ITS EDUCATIONAL PROGRAMS APPEAR REASONABLE TO YOU?

A. No. The Company is proposing to spend a considerable amount on what it represents as "energy efficiency education" when in fact, many of these expenditures appear to be promoting the Company's image and creating goodwill. Total expenditures on such items as advertising, booths at conventions, labels, wallet cards, and other similar items comprise over 50 percent of the Company's educational program. What is more troubling is that program administration, including, presumably, monitoring and verification ("M&V") costs are not explicitly identified in this budget. The TRA should reject this program given its lack of clearly defined goals, metrics, and accountability.

Q. CAN YOU PLEASE DISCUSS THE COMPANY'S PROPOSED RESIDENTIAL ENERGY EFFICIENCY MEASURES?

A. Yes. The Company is proposing five residential energy efficiency measures within its energySMART program including:

- Programmable thermostats;
- Low income weatherization;
- High efficiency furnace/boiler incentive;
- Tankless water heater incentive; and
- High efficiency storage water heater incentive.

Q. HOW ARE THESE RESIDENTIAL PROGRAMS STRUCTURED?

A. Generally, all of these programs are based upon offering customers rebates for the installation of high efficiency natural gas appliances. The

Company is proposing to offer a rebate of $500 per customer for its high efficiency furnace and tankless water heater program, and a $150 rebate to customers that participate in its high efficiency storage water heater program. The Company is also giving away free programmable thermostats to 1,500 customers at a value of $20 each. Lastly, the Company is proposing to provide a rebate of $1,650 per household in its low-income weatherization program.[9]

Q. HOW MUCH IS THE COMPANY PROPOSING TO SPEND ON THESE RESIDENTIAL PROGRAMS?

A. The Company is proposing to spend approximately $445,000 per year, or a total of $1.8 million over a four year period on its residential programs. The residential efficiency measures collectively are anticipated to create 107,600 therms of energy efficiency savings per year, for a total of 430,400 therms over a four year period.

Q. IS THE COMPANY PROPOSING ANY COMMERCIAL MEASURES?

A. Yes, the Company is proposing five separate commercial energy efficiency measures that include:

- Food service equipment measure;
- High efficiency furnace/boiler measure;
- Tankless water heater incentive;
- High efficiency water heater incentive; and
- Booster water heater incentive.

[9] The program is limited to 120 households per year.

Like the residential measures, the Company is proposing to offer $500 per participant rebate on its furnace and water heating measures. The Company is proposing to offer a $200 rebate for each participant in its booster water heater and food service equipment measures. The Company is offering a $300 rebate for those commercial customers participating in the high efficiency water heater measure, an amount that is double the comparable residential measure.[10]

Q. HOW MUCH IS THE COMPANY PROPOSING TO SPEND ON ITS COMMERCIAL MEASURES?

A. The Company is proposing to spend $147,000 per year for the next four years on its commercial measures. The commercial measures are anticipated to create 59,535 therms per year in natural gas savings, for a total of 238,140 therms over a four year period.

Q. DID THE COMPANY CONDUCT ANY COST-EFFECTIVENESS ("CE") ANALYSES OF ITS PROGRAMS?

A. Yes, the Company conducted a CE analysis on each of its proposed measures. The Company indicated that it followed the protocols of the *California Standard Practice Manual* in determining the cost effectiveness of the ten residential and commercial programs.[11] The Company tested each of its programs using the tests of the California Standard Practice Manual.[12] I have provided a copy of the summary results from the Company's cost-effectiveness

[10] Direct Testimony of Daniel J. Nikolich, Exhibit DJN-1, as updated in Response to CAPD Question 151, Attachment 151-2.
[11] Direct Testimony of Daniel J. Nikolich, pp. 3-4.
[12] Ibid.

tests, as they were revised in Response to CAPD Question 151, Attachment 151-2, in Exhibit DED-4.

Q. WOULD YOU DESCRIBE THE COST EFFECTIVENESS TESTS RECOMMENDED IN THE CALIFORNIA STANDARD PRACTICE MANUAL?

A. Yes. There are four tests that are recommended in the California Standard Practice Manual. These tests, as defined by the manual, are set forth below:

> The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.
>
> The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.
>
> The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.
>
> The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.[13]

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[13] California Standard Practice Manual, July 2002.

Q. WHAT WERE THE COST EFFECTIVENESS RESULTS FROM THE PARTICIPANTS TEST?

A. The Company finds, not surprisingly, that most of its proposed measures pass the Participants Cost test, which examines the cost-effectiveness of a given energy efficiency measure from a participating customers' perspective. Total costs include the installation costs from the program, while benefits are generally the summation of energy savings and rebates. The lowest scores arising from the Company's participant test analysis is for the residential high efficiency furnace offerings and the tankless water heater measure.

Q. WHAT WERE THE COST EFFECTIVENESS RESULTS FROM THE NON-PARTICIPANTS, OR RATE IMPACT MEASURE ("RIM") TEST?

A. The Company's analysis found that every single residential and commercial measure failed the non-participant or RIM test, except the programmable thermostats. This result leads an important conclusion: the subsidies covered by non-participating customers, in terms of the lost revenues they will pay for program participation, as well as the subsidies they will pay for the actual program incentives, results in an economic loss for over 90 percent of CGC's customers that do not participate in these energy efficiency programs. This is problematic when one group of stakeholders (non-participating customers) subsidizes another (participating customers and CNG's shareholders).

Q. HOW LARGE ARE THE TOTAL LOST BASE REVENUES FROM THE RESIDENTIAL AND COMMERICAL PROGRAMS COMBINED?

A. The Company estimates $2.5 million for total program (residential and commercial) lost base revenues for the first five years of the program. These revenues are incurred over the course of the assumed measure life of the measures offered by the program. The weighted average measure life for the Company's entire portfolio of energy efficiency measures is 16.2 years. This results in an average annual lost base revenue impact of $501,256 for the first five years, which is less than 3 percent of current total Company base revenues. However, as I have stated before, some caution should be used in the comparison since the Company's numbers are in error and overstate a more appropriate estimate of lost revenues.

Q. HAVE ANY OTHER COMMISSIONS RECOGNIZED THE NEGATIVE IMPACTS THAT THESE CROSS SUBSIDIES CAN HAVE ON NON-PARTICIPATING CUSTOMERS?

A. Yes. The Virginia State Corporation Commission ("VSCC" or "Corporation Commission") raised a number of concerns about the impact these taxes, or cross-subsidies, could have on non-participating customers, as well as raising issues about these programs' cost effectiveness in the face of a decoupling mechanism. The Corporation Commission recently issued, and submitted, a report to the Virginia legislature summarizing its recent experience with energy efficiency and revenue decoupling as required under the "Natural Gas Conservation and Ratemaking Efficiency Act" (hereafter "Efficiency Act").[14]

[14]Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate

While the Corporation Commission did acknowledge that provisions of the Efficiency Act did, or will, encourage energy efficiency investment, it expressed the following concerns regarding program cost effectiveness and ratepayer impacts:

> Sufficient evidence does not yet, however, exist to conclude that these investments are cost-effective under either the RIM or TRC tests. Initial estimates generally indicate that these investments will be beneficial from some perspectives. However, these same estimates indicate that the <u>natural gas utility efficiency plans may negatively impact the non-gas rates paid by natural gas consumers and that non-participations in the programs offered pursuant to these plans will be negatively impacted</u>. Additionally, the cost benefit <u>results do not consider any revenue impact that might be attributable to the implementation of decoupling mechanism</u>. Such revenue changes could significantly impact the costs and benefits of a utility's overall conservation plan when viewed from a utility customer's perspective.[15]

Q. DID THE COMPANY ACKNOWLEDGE THE FACT THAT ITS PROPOSED PROGRAMS FAILED THE RIM TEST?

A. Yes. The Company acknowledged that its programs failed the RIM test on an individual and collective basis. The Company justified proposing these programs based upon the conclusion that:

> …an increase in gas costs will push this test to a favorable result. Given the relative volatility of natural gas prices of the past several years and the current low gas prices, future increases in gas costs may be highly likely.[16]

Q. DO YOU AGREE WITH THE COMPANY'S CONCLUSIONS REGARDING THE FUTURE OUTLOOK FOR GAS PRICES AND THE COST EFFECTIVENESS OF ITS PROGRAM?

Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

[15] Ibid, emphasis added.

[16] Direct Testimony of Daniel J. Nikolich, 16: 1-3.

A. Natural gas is an energy commodity and like many energy commodities it can be highly volatile. But volatility in the industry is nothing new: gas prices were volatile prior to the winter of 2000-2001, were volatile during the challenging period between 2005 and 2008, and even in today's depressed markets, are likely to continue to be volatile. The results of CE analyses are not, however, driven by volatility, but the absolute level, and change, in the price of natural gas. Few natural gas analysts in the industry today anticipate higher natural gas prices anytime in the year future, especially prices that will rise to the levels after the hurricanes of 2005.

Q. WHAT ARE THE COST EFFECTIVENESS RESULTS FROM THE TOTAL RESOURCE COST ("TRC") TEST.

A. The Company's TRC test results are all positive, indicating that when all of the benefits and costs are pooled, benefits will exceed costs. This cost-effectiveness test is biased since it does not include the potential rate increases that ratepayers will have to incur by supporting the Company's revenue decoupling tracker.

Q. DID ANY OF THE COMPANY'S MEASURES FAIL THE TRC TEST?

A. Yes, prior to making the revisions to its CE analysis, one measure failed the TRC test, indicating that the savings creating from this measure is still not large enough to offset the guaranteed lost revenues and subsidies paid by non-participating ratepayers. The residential tankless water heating program failed the TRC test, and the commercial high efficiency furnace program is only on the cusp of being "cost-effective." However, when the Company submitted a revised

CE analysis in Response to CAPD Question 151, the residential tankless water heater program produced a TRC score of 1.26. This change in the underlying assumptions in fuel prices changed the TRC result for this program and increased the score for the other programs.

Q. CAN YOU DISCUSS THE ASSUMPTIONS USED BY THE COMPANY IN DEVELOPING THESE COST EFFECTIVENESS RESULTS?

A. Yes, the Company utilized a number of input assumptions in developing its cost-effectiveness results. The more significant of the assumptions included in the Company's cost-effectiveness analysis are:

- Avoided utility costs, and participant benefits, are based upon PGA rates that include:
    - Purchased commodity costs (commodity natural gas prices) that are taken from the most recent month available and then are increased at a rate comparable to the NYMEX strip settlement prices.
    - Capacity costs that were based upon the commercial C-2 purchased gas demand rate charged to customers as of October 1, 2009, and escalated each year by a constant inflation rate of 2.5 percent that appears to have been developed as some type of average from the Consumer Price Index-Urban ("CPI-U").
- An inflation rate of 2.5 percent was applied to all rebates and measure equipment costs.

- A discount rate based upon the Company's requested overall return of 8.28 percent
- Installation costs for the equipment associated with each of the proposed measures.
- Measure lives for each measure that vary from 15 years to as long as 25 years.
- Administrative and marketing costs.
- Number of participants.
- Annual energy savings from each of the proposed measures.
- Limited free riders and kickback effects.

Q. ARE THERE ANY DEFICIENCIES IN THE COMPANY'S COST EFFECTIVENESS ASSUMPTIONS?

A. Yes, there are a number of deficiencies with the Company's CE analysis that include:

- An exaggerated price inflation forecast that was used to accelerate capacity costs creating unreasonable increases in forecasted retail rates.
- An incorrect estimate of lost revenues.
- Understated measure equipment costs that have the effect of overstating program benefits.
- Overstated participation rates that are inconsistent with recent program experience throughout the U.S. and even with the Company's own affiliates.

- Overstated measure lives that lead to over-estimates of efficiency savings over time.
- Overstated incremental energy efficiency savings levels that exaggerate the potential program savings and cost-effectiveness.
- Understated administrative and marketing costs that will not generate the levels of participation anticipated by the Company. This unnecessarily increases program benefits.

Q. HAS THE COMPANY UPDATED ITS COST EFFECTIVENESS ANALYSIS TO ACCOUNT FOR RECENT TRENDS IN NATURAL GAS SUPPLIES AND PRICES?

A. Yes. The Company recently revised its cost effectiveness results by updating, among other things, its natural gas price projections.[17] A graph of the Company's original and revised gas price projections over time has been provided in Exhibit DED-5. A comparison of the changes between the Company's original cost effectiveness findings and the one provided in discovery has been summarized in Exhibit DED-6.

Q. ARE THERE ANY PROBLEMS ASSOCIATED WITH THE COMPANY'S CAPACITY COST ASSUMPTIONS?

A. Yes. The Company notes that part of its gas price forecast includes a capacity component, presumably for transportation and storage. The Company uses the C-2 purchased gas demand rate and inflates this over time as the proxy for the capacity cost component of its avoided supply costs. Such an approach

[17] Response to CAPD Question 151 and CAPD Question 157.

overstates capacity costs since they do not follow the rates of inflation seen in the CPI-U. Exhibit DED-7 outlines the historic capacity charges on the Tennessee Gas Pipeline, East Tennessee Gas Pipeline and Southern Natural Gas Company ("SONAT") systems. There has been little change in these rates over the past decade. Thus, the Company's assumption that capacity charges will escalate at a rate of 2.5 percent per year is without empirical support.

Q. CAN YOU EXPLAIN HOW THE COMPANY UNDERSTATES ITS LOST BASE REVENUE ESTIMATE?

A. Yes. The Company's true lost base revenues should be based on the incremental base rate (i.e., volumetric base rate) paid by those customers participating in the various energy efficiency measures. In developing its RIM test the Company failed to include the lost revenues from its base rates. By excluding this component of the RIM cost, the Company understated its lost base revenues.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE ESTIMATE OF THE COMPANY'S LOST BASE REVENUES?

A. Yes, I developed an estimate of the Company's lost base revenues that is based upon the incremental base rates for each customer class that may participate in the various energy efficiency measures. I estimate the first five-year average annual lost base revenue impact of $202,235. The true estimated lost base revenues are less than 1 percent of current total Company base revenues. Such a small level of lost revenues should be grounds enough to reject the Company's proposed revenue decoupling mechanism.

Q WILL THIS CHANGE THE RIM CE RESULTS?

A Yes, making this correction to the calculation of lost base revenues will actually reduce the RIM test results since the "cost" (lost base revenues) is higher. These RIM test results, however, are still somewhat skewed under the Company's proposal since they fail to account for the tax that will be placed upon non-participating customers through the decoupling mechanism.

Q. LET'S DISCUSS YOUR NEXT CONCERN. CAN YOU EXPLAIN THE DEFICIENCIES IN THE COMPANY'S INSTALLATION AND EQUIPMENT COST ASSUMPTIONS?

A. The Company's measures are based upon a variety of assumed installation and equipment costs that, in some instances, are lower than those used in other CE analyses, or found in the market. Artificially low installation and equipment costs will deflate the cost of adopting energy efficiency measures, thereby artificially increasing the program's energy efficiency savings and participation. Exhibit DED-8 provides each program measure and the key assumptions used in the Company CE model compared to the ones that I recommend. As shown, I am recommending a change in the tankless water heater installation and equipment costs and the commercial food service installation and equipment costs. Although I have not made changes to the other program equipment and installation costs this should not be considered an endorsement of the Company's estimates.

Q. CAN YOU DEFINE A "FREE RIDER" AND WHY IT IS IMPORTANT TO CONSIDER THESE IMPACTS IN A COST EFFECTIVENESS ANALYSIS?

A. A free rider is defined as a household or business that receives a rebate from an energy efficiency program, but would have participated in the program without the incentive. Utilities need to account for the presence of free rider problems in order to determine the true impact of their conservation program efforts and expenditures: free ridership will result in some share of program expenditures being wasted since ratepayers are supporting efficiency applications that would have occurred without the utility program. The Company's analysis, however, adjusted for free riders in only one instance: the residential high efficiency furnace program, which assumed a 29 percent free ridership level. The Company excluded free rider adjustments in its other cost effectiveness analyses based upon its position that none were needed in instances when the measure lives were shorter than the equipment life.[18]

Q. EARLIER YOU REFERENCED KICKBACK EFFECTS. WHAT ARE THOSE AND WHY ARE THEY IMPORTANT IN EXAMINING COST EFFECTIVENESS?

A. Kickback effects can be defined as increases in usage that can arise from the lower cost of operating an appliance, or the increased usage that may arise from the increased disposable income generated by the energy savings. An example may include a customer that turns his heating thermostat up to attain a higher level of satisfaction, for the same total cost, from a more efficient space heating unit. These kickback effects can reduce overall effective savings from energy efficiency programs.

[18] Response to CAPD Question 157.

Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE REGARDING KICKBACK EFFECTS?

A. The Company's original filing, and its cost effectiveness analysis, assumed no kick-back effects. The Company did, however, provide a later revised analysis that included kickback effects for its residential high efficiency furnace incentive and its residential tankless water heating incentive.[19] The Company did not provide an explicit definition for the kickback assumption it used in its analysis but simply posited that "…kickback benefits were accounted for by using an average savings level based upon actual data in which there were some instances where customers actually added load rather than reducing their consumption."[20]

Q. DID YOU EXAMINE THE DIFFERENCES BETWEEN THE TWO STUDIES TO ASCERTAIN HOW THE COMPANY ADJUSTED FOR KICK-BACK EFFECTS?

A. Yes. Exhibit DED-9 graphs the annual changes in energy savings resulting from the kick-back assumptions included in the high efficiency furnace measure and the tankless water heating measure. Four lines appear in each graph: (a) two lines show the forecasted energy savings for the Company's original and revised analyses; and (b) two lines show the forecast demand savings for the Company's original and revised analyses. Page 1 shows the results for the high efficiency furnace measure, and page 2 shows the results for the tankless water heating measure. The annual average difference between the

[19]Response to CAPD Question 151 and CAPD Question 157. This is also the analysis that revised the Company's assumed natural gas price forecast.

[20]Response to CAPD Question 157.

original and revised high efficiency furnace measure is 59 percent. The annual average difference between the original and revised tankless water heating measure is 54 percent.

Q. HAVE YOU RE-ESTIMATED THE COST EFFECTIVENESS OF THE COMPANY'S PROPOSED ENERGY EFFICIENCY PROGRAM USING MORE APPROPRIATE ASSUMPTIONS?

A. Yes. Exhibit DED-10 provides a summary outlining the revised assumptions I used in my cost effectiveness analysis of the Company's proposed energy efficiency program. In summary, the revised assumptions I utilized in my cost-effectiveness analysis included:

- Elimination of the inflation adjustment on the capacity costs and inclusion of lost base revenues.
- Use of more realistic residential service lives for the programmable thermostat, low income weatherization, high efficiency furnace and the high efficiency storage water heater.
- Use more reasonable commercial service lives for the high efficiency storage water heater.
- The use of more realistic installed cost assumptions for the tankless water heater and food service programs.
- The addition of moderate assumptions on free ridership and kick-back effects.

Q. HOW DO YOUR REVISED COST EFFECTIVENESS FINDINGS IMPACT THE FORECASTED ENERGY EFFICIENCY SAVINGS LIKELY TO ARISE FROM THE COMPANY'S ENERGY EFFICIENCY PROGRAM?

A. They significantly reduce the overall anticipated savings and number of participants associated with an already limited program.

Q. HOW DO THESE REVISED COST EFFECTIVENESS FINDINGS IMPACT THE ESTIMATED LOST BASE REVENUES FROM THE PROGRAM?

A. They significantly reduce an already mediocre level of lost base revenues associated with the Company's original estimates. The first five-year lost base revenues decrease from the $2.5 million originally estimated by the Company, to a more realistic level of some $1.0 million.

Q. EARLIER YOU OUTLINED THE CONCERNS EXPRESSED BY THE VIRGINIA CORPORATION COMMISSION. DOESN'T THE COMPANY HAVE AN AFFILIATE IN VIRGINIA?

A. Yes, the Company's affiliate, Virginia Natural Gas ("VNG") operates in Virginia and the VSCC's review of VNG's energy efficiency and decoupling efforts were a key component of its findings. The Corporation Commission, while finding that revenue decoupling has, or will stimulate energy efficiency investments, expressed considerable frustration with the performance of both VNG's energy efficiency results and revenue decoupling. The Corporation Commission's concerns can be summarized as follows:

> VNG's revenue decoupling mechanism will compensate the Company for energy reductions of approximately 10 million Ccfs while VNG's own estimates indicate that its programs have generated reductions of less than 116,000 Ccfs. As such, use of

> the specified non-gas revenue required by the Natural Gas Conservation Act [i.e., revenue decoupling] provides significant additional revenue to VNG over and above compensation needed to offset lost revenues attributable solely to VNG's efficiency efforts.[21]

Q. HOW WELL DID VNG'S ENERGY EFFICIENCY PROGRAMS PERFORM?

A. Not very well. I have provided a summary of the first year results that were included in the Virginia Efficiency Report in Exhibit DED-11 which consists of four pages. The first page of the exhibit provides the participation levels by measure since the program's inception in May, 2009. The second page provides program savings in Ccfs. The third page provides program costs, while the fourth page provides revenue decoupling charges collected from ratepayers for the full year (2009).

Q. WHAT CONCLUSIONS CAN BE REACHED FROM THESE PROGRAMS?

A. There are several conclusions that can be reached from the VNG experience to date.

- Only 5,652 residential customers participated in VNG's energy efficiency program. This represents about 2.3 percent of total VNG residential customers.

[21] Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009, p. 18, emphasis added.

- First year efficiency savings were only 116,120 Ccfs, representing 0.1 percent of total VNG residential sales.
- Program costs were $829,313 or 0.4 percent of total 2009 total residential revenues. Program costs were $146 per participant and exclude education and outreach efforts (valued at another $94,370 for 2009).
- VNG ratepayers received a revenue decoupling surcharge in every month from January through September. During this period, revenue decoupling surcharges totaled $4.7 million.
- Non-participating customers paid almost $42 per Ccf of first year savings in program administrative costs, revenue decoupling balances, and lost base revenues.

Q. HAVE YOU DONE ANY COMPARISONS TO VNG'S AND CGC'S ENERGY EFFICIENCY PROGRAMS?

A. Yes. The VSCC Report also included a table outlining the cost effectiveness estimates that were provided prior to program implementation (i.e, the CE study upon which the program, and revenue decoupling, were approved). A comparison of these programs, to the ones provided by CNG, has been provided in Exhibit DED-12. Interestingly, many of the VNG programs have cost effectiveness assumptions and results that are comparable to the ones offered by the Company in this proceeding. In addition, one CGC-proposed program has a RIM test result that is greater than the one proposed by VNG (i.e., high efficiency furnace).

Q. WOULD YOU COMPARE THE FIRST YEAR PARTICIPATION LEVELS AND SAVINGS IN THE VNG PROGRAM TO THE FORECASTS PROVIDED BY CGC?

A. Yes. In its first year, VNG savings in its programmable thermostats program was 4 Ccf per participant, which is far lower than CGC's forecast of 26 Ccf per participant. Similarly, VNG's participation in its high efficiency furnace program was 60 therms per participant, whereas CGC forecasts 67 therms.

Q. SHOULD THE TRA BE CONCERNED ABOUT THE CLOSE COMPARABILITY OF THE FORECASTED SAVINGS FROM THE VNG AND CGC PROGRAMS?

A. Yes. The VNG programs, like those proposed by the Company in this proceeding, had relatively rosy depictions of the cost-effectiveness, participation, and energy savings that would result from its residential energy efficiency program. Actual participation and savings rates proved those forecasts to be incorrect which resulted in programs that are question the likelihood of cost-effectiveness even under a biased measurement tool. The VNG experience, coupled with a revenue decoupling tracker that shifted $4.7 million in revenues that were over and beyond lost base revenues to the utility shareholders, bodes unfavorably for a positive Tennessee experience.

Q. SHOULD THE TRA REJECT THE COMPANY'S ENERGY EFFICIENCY PROGRAM?

A. Yes, the TRA should reject the Company's proposed energy efficiency program. The program has questionable cost-effectiveness results, and will cause over 90 percent of the Company's customers to subsidize customers participating in the proposed energy efficiency programs. The Company's original analysis showed that 5 percent of its customers will receive an net present value ("NPV") benefit of $10.7 million that will be paid for by 95 percent of the customers at a NPV cost of $5.7 million. While the absolute level of benefits are greater than the absolute level of costs (resulting in a TRC greater than one), these benefits are not shared among all ratepayers, but restricted to participating customers alone: there are no reduced transmission capacity payments benefits, there are no reduced storage premium credits, there are no reduced reservation or demand charges for commodity purchases that would extend benefits to non-participating customers that are not taking advantage of a program. Such an outcome is untenable with traditional regulation that seeks to balance the interests between and among customer classes.

IV. PROPOSED DECOUPLING TRACKER

Q. WOULD YOU PLEASE DESCRIBE THE PURPOSE OF THE COMPANY'S AUA MECHANISM?

A. Yes. The Company's proposed AUA mechanism, or revenue decoupling tracker, has been proposed to "break the link" between sales and revenues that purportedly creates a disincentive for the development of cost effective energy efficiency programs. According to the Company:

> . . . the existing rate design approach, which unequivocally incentivizes utility behavior, links its ability to recover authorized revenues to customer sales or throughput. Specifically, <u>eliminating the existing throughput incentive is necessary</u> to unlock the

> potential for utilities to play a significant role in advancing Tennessee's aggressive energy policy agenda.[22]

Later, the Company notes:

> … The Company's proposal will align the interests of CGC and it customers and is consistent with the energy policy initiatives mandated by the federal government in PURPA and the Stimulus Act and by the Tennessee General Assembly in Tenn. Code Ann. § 65-4-126.[23]

Q. IS REVENUE DECOUPLING IS NECESSARY AND MANDATED BY THE ARRA, PURPA, OR TENNESSEE'S ENERGY POLICY AGENDA?

A No, neither PURPA nor Section 65-4-126 requires, mandates, nor finds revenue decoupling necessary in order to support energy efficiency. In fact, each of the Directors were very clear at the conclusion of the most recent Piedmont Natural Gas decoupling case that they in no way interpret state legislation as requiring revenue decoupling. This position was stated very clearly by Director Roberson:

> This petition is the first opportunity this authority has had to address the statute enacted by the legislature last year establishing the state policy of promoting energy conservation by requiring the TRA in an appropriate proceeding to ensure that there is a proper alignment of regulated utility's financial interest to promote said policy. The legislature established the policy but allowed the TRA wide latitude in how and when to implement it.
>
> I will state that there is no reference to decoupling in the statute that was enacted.[24]

Q. DID ANY OTHER DIRECTORS OBJECT TO THE CONCLUSION THAT STATE LAW REQUIRES REVENUE DECOUPLING?

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[22] Direct Testimony of Daniel P. Yardley, 9:3-7, emphasis added.
[23] Direct Testimony of Steve Lindsey, 8:17-20, emphasis added.
[24] Transcript of Authority Conference, January 25, 2010, p. 25, emphasis added.

A. Yes, Director Hill also arrived at an equally firm position on this matter by correctly noting:

> Piedmont spent a great deal of time, both on paper and during the hearing itself, arguing that Tennessee's recently adopted conservation policy codified in TCA 65-4-126 is a clear statement of policy strongly supporting decoupling.
>
> I agree with the Consumer Advocate that this view is highly unwarranted. <u>There is no evidence that decoupling is the only method by which to achieve the conservation goal set out by the legislature that the TRA seek to implement a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently.</u>[25]

Q. HOW DID DIRECTOR FREEMAN RULE IN THIS MATTER?

A. Director Freeman not only noted that revenue decoupling is not required under state law, but that any utility seeking a new financial incentive to pursue energy efficiency has a relatively high evidentiary burden of proof:

> I find that Piedmont <u>failed to present sufficient evidence to justify a need for a new financial incentive</u> in order to comply with state and federal law regarding conservation while earning a just and reasonable rate of return. <u>The Authority must be able to determine the benefit to consumers before giving Piedmont an additional financial incentive</u>.[26]

Q. DO YOU THINK CGC HAS MET THE EVIDENTIARY STANDARD ENVISIONED BY DIRECTOR FREEMAN?

A. No. The Company has not provided any evidence that traditional regulation in Tennessee has failed or that the current method of regulation has created a negative financial impact upon its incentives to promote energy efficiency. The TRA's current regulatory approach provides ample opportunities for CGC, and other regulated utilities, to provide cost-effective energy efficiency

[25] Ibid., p. 29, emphasis added.
[26] Ibid., p. 21.

service to its ratepayers. Thus, the Company's revenue decoupling proposal should be rejected since it has failed to provide an affirmative showing that current regulation in Tennessee is deficient in supporting energy efficiency.

Q. IS THE COMPANY'S POSITION MISPLACED?

A. Yes, and from a policy analyst's perspective, revenue decoupling is not required, nor highlighted as the preferred mechanism for providing financial support for utility-sponsored energy efficiency. There are a variety of other mechanisms that the TRA could adopt that would not only meet the provisions included in both PURPA and TCA Section 65-4-126, but would be superior policy alternatives to the revenue decoupling proposal recommended by the Company. I will discuss a number of these potential policy opportunities in the later sections of my testimony.

Q. ARE YOU AWARE OF ANY ARRA ENERGY EFFICIENCY FUNDS THAT HAVE BEEN DENIED OR REMOVED FROM ANY STATE BECAUSE OF ITS DECOUPLING ADOPTION STATUS?

A. No, not that I am aware. Exhibit DED-13 shows that every state in the U.S. received energy efficiency dollars as allocated by the ARRA. The exhibit shows the state and dollars allocated by decoupling status. Contrary to the Company's suggestions, no state has been deprived nor had their appropriated energy efficiency dollars removed as a consequence of not having revenue decoupling.

V. INCONSISTENCY OF DECOUPLING WITH ECONOMIC THOUGHT AND REGULATORY PRACTICE

Q. DO YOU THINK REVENUE DECOUPLING IS CONSISTENT WITH LONG RUN REGULATORY PRACTICES AND POLICIES?

A. No. Revenue decoupling is clearly a policy that has been utilized in the past and was abandoned almost as quickly as it was implemented. In the early 1990s, at least seven different states adopted revenue decoupling for their respective electric utilities. By 2000, no states had an active revenue decoupling mechanism in place, including California. If revenue decoupling were a proven and effective regulatory approach more states would have adopted this mechanism in the past and it would be almost commonplace today. Instead, those states that adopted and ultimately rejected revenue decoupling found that either: (a) the mechanisms failed to create any significant increases in energy efficiency savings, raising questions about the *a priori* assumption of utility disincentives; (b) the mechanisms were incompatible with increasingly competitive retail power and natural gas markets; or (c) the mechanisms resulted in an unreasonable level of risk shifting that was inconsistent with sound regulatory policy. To suggest otherwise is simply a wishful, revisionist interpretation of those states' past experiences.

Q. WASN'T DECOUPLING PRIMARILY REMOVED BECAUSE OF RETAIL COMPETITION?

A. In many instances, but not all, revenue decoupling was removed because of the adoption of retail competition. While many decoupling advocates would like to use retail choice as a convenient excuse for the past removal of decoupling mechanisms they gloss over the rationale for why decoupling and retail competition are incompatible: no customer in a competitive market, with competitive opportunities, would willingly: (1) pay for programs for which he or she receives no benefits (i.e., the RIM problem); or (2) indiscriminately make any market participant whole for revenue losses regardless of source or rationale (i.e, the overcompensation of lost base revenues problem). Such a result would be inefficient and lead to societal losses. Thus, the rationale for removing revenue decoupling in a retail choice environment was its inconsistencies with competition and efficiency, not some arbitrary policy choice made by state regulators. Interpreting the rationale for these past policy changes otherwise is simply revisionist history.

Q. SHOULD UTILITIES BE GIVEN A REASONABLE OPPORTUNITY TO EARN A RETURN ON AND OF THEIR INVESTMENTS AS WELL AS THEIR PRUDENTLY INCURRED COSTS?

A. Yes, but it is a well recognized fact in utility regulation that in any given year, allowed and achieved returns are not likely to be exactly the same. In fact, such an event usually only occurs by coincidence and while utilities are given a reasonable <u>opportunity</u> to earn a return on and of their investments, these opportunities are not synonymous with an <u>entitlement</u> (or guarantee). Regulatory practice, and the academic literature of utility regulation, recognize that achieved rates of return can be higher or lower than allowed returns and the positive incentives associated with regulatory lag quite often inure to the utility and its shareholders because efficiency improvements that occur between rate cases can increase earnings, benefiting shareholders.[27] Importantly, regulatory lag can be an important policy tool in controlling utility costs which ultimately can lead to lower rates.[28]

Q. CAN REVENUE TRACKER MECHANISMS, LIKE REVENUE DECOUPLING, LEAD TO ANY REGULATORY PROBLEMS OR DISINCENTIVES?

A. Yes. Trackers of all types, including revenue decoupling, will ultimately lead to higher utility costs because they eliminate the positive incentives of regulatory lag on a utility's ongoing operational costs. It is a basic economic fact that rational utility management has little incentive to control costs (operational and capital) if it has no effect on the utility's profits,[29] which is precisely the situation that occurs when a utility is able to pass higher costs through to ratepayers with little to no regulatory scrutiny and with minimal consequences on sales. Such an approach is completely at odds with traditional regulatory principles and ratemaking practices, and because the Company's proposals also exclude any type of benchmarks or standards, they are also contrary with most alternative or performance-based regulatory approaches.

Q. IS REVENUE DECOUPLING BASED UPON ANY SOUND ECONOMIC PRINCIPLES OR ACADEMIC THOUGHT?

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[27] W.K. Viscusi, J.M. Vernon, J.R. Harrington, Jr. (1997) *Economics of Regulation and Antitrust*, Second Edition. Cambridge: MA: MIT Press, 380.

[28] J.C. Bonbright. (1961). Principles of Public Utility Rates. New York: Columbia University Press, 53.

[29] See Alfred Kahn. (1988). *The Economics of Regulation: Principles and Institutions*. Cambridge, MA: MIT Press: Vol. 2 (Institutional Issues): 48.

A. No, and unlike the better part of utility regulation, revenue decoupling has virtually no support or basis in the academic and theoretic economic literature.[30] The entire premise of revenue decoupling, that firms (utilities) are revenue maximizers instead of profit maximizers, is entirely inconsistent with the fundamental principles found in a basic economics textbook. In fact Professor Harry Trebing, the long-recognized and respected professor, utility economist, and former director of the Institute of Public Utilities[31] at the Michigan State University characterized revenue decoupling as a "scholarly abomination."[32]

Q. HOW DO TRACKERS CONTRADICT TRADITIONAL REGULATORY THINKING?

A. In the early 1960s, a seminal article was published that dramatically influenced the theory and practice of utility regulation and the theoretical economics of regulated firms. This article, authored by Professors H. Averch and L. Johnson, and published in the *American Economic Review* in 1962,[33] posited that rate of return regulation creates an incentive for regulated utilities to overcapitalize resulting in an inefficient utilization of resources and higher than optimal rates. This article was met with a flurry of scholarly research attempting to empirically verify what became known as the "A-J effect," as well as examining

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[30]Brennan, Timothy J. (2008). "'Night of the Living Dead' or 'Back to the Future'? Electric Decoupling, Reviving Rate-of-Return Regulation and Energy Efficiency." Washington, DC: Resources for the Future Discussion Paper No. 08-27.

[31]See http://ipu.msu.edu/. The Institute of Public Utilities at the Michigan State University has a decades-long tradition of training regulatory commission staff and new regulatory commissioners through their annual two-week training sessions at MSU commonly referred to as "Camp NARUC" by those who have attended the event.

[32]Brennan, Timothy J. (2008). "Decoupling." Presented to the Institute of Public Utilities, Michigan State University, 40th Annual Regulatory Policy Conference.

[33]H. Averch and L. Johnson. (1962) "Behavior of the Firm under Regulatory Constraint." *American Economic Review*. 52:1052-1069.

the conditions under which the effect would, and would not, be sustained. Rejoinders to the research noted that two characteristics of the regulatory process tended to temper the likelihood and prevalence of the A-J effect: (1) the possibility of disallowances through the prudence review process and (2) the positive resource efficiency incentives created by “regulatory lag.”

Q. HOW DOES REVENUE DECOUPLING UNDO THESE EFFICIENCY-CREATING INCENTIVES?

A. Revenue decoupling reduces these resource efficiency incentives in two ways. First, if revenue decoupling does in fact reduce the tendency for rate cases, as its proponents would suggest, then the mechanism would reduce the potential use of disallowances in tempering bad expenditure and investment decisions. Second, if utilities are given the ability to change, and generally increase their rates, without any annual justification, then the discipline typically imposed by regulatory lag is completely removed as well. As noted earlier, the theory and practice of public utility regulation is based upon the well-recognized observation that regulatory lag gives utilities an incentive to reduce costs between rate cases and become more efficient since the benefits of those efficiencies will typically inure to shareholders.[34]

Q. HAS THE TRA RECOGNIZED THE DISINCENTIVES FOR COST EFFICIENCY CREATED BY REVENUE DECOUPLING?

A. Yes. In the Piedmont decision, Director Roberson clearly recognized the fundamental importance of regulatory lag in facilitating cost efficiencies, and the

[34] Again, see Kahn, *The Economics of Regulation*, 48.

fundamental problem revenue decoupling creates in eliminating this incentive. Director Roberson noted that revenue decoupling:

> … appears to eliminate or significantly reduce the positive effect of regulatory lag. In theory, regulatory lag provides an incentive for utilities to operate efficiently in order to maximize profits. For a monopoly, this concept is very important, and any new rate design adopted by the Authority should not forgo the benefits of this traditional ratemaking principle.[35]

Q. IS REVENUE DECOUPLING CONSISTENT WITH SOME OF THE MORE RECENT DEVELOPMENTS IN REGULATORY ECONOMICS?

A. No. One of the more recent contributions to the literature and practice of public utility regulation has included a recognition of the importance and role of information in conditioning effective regulatory policy outcomes. Theoretical developments in regulatory economics over the past twenty years recognize that the effectiveness of the traditional regulatory process can be limited by the presence of asymmetric information between regulators and regulated companies. Quite often regulators have less information over costs and other variables important in determining the cost of service than their regulated utilities. When such conditions exist, incentive or performance-based forms of regulation, which tie rewards to observable performance measures tend to lead to more efficient outcomes benefiting ratepayers and shareholders alike. Decoupling rates from revenues and performance, therefore, runs counter to not only traditional regulatory thinking, but the more recent developments and innovations to this body of literature and understanding over the past two decades.

[35] Transcript of Authority Conference, January 25, 2010, p. 26.

Q. ARE THERE ANY OTHER DISINCENTIVES THAT CAN ARISE FROM REVENUE DECOUPLING?

A. Yes, an important disincentive that may arise with decoupling is that utilities may be less likely to take steps that reduce price volatility for their customers through reasonable risk management practices in gas supply procurement. While commodity gas costs are a pass-through item, they significantly impact overall average rates paid by households, businesses and industries. Overall average rates are composed of the PGA and a base rate component. Exhibit DED-14 shows that it is not entirely coincidental that LDCs started rapidly requesting revenue decoupling mechanisms in the back-draft of Hurricane Katrina and the volatile pricing period following 2005. This price volatility creates risks for LDC revenues even though the commodity component is a direct pass through to customers. Decoupling sales and distribution revenues, therefore, can reduce a utility's incentive to manage its gas price risk (volatility) since it results in no sales loss to the LDC.

Q. DOES THE POSSIBILITY OF RATE DECREASES CREATE A POTENTIAL BENEFIT FOR RATEPAYERS?

A. Not necessarily, particularly for relatively risk-averse ratepayers. While revenue decoupling holds out the purported opportunity for rate decreases, this opportunity comes at a cost. Revenue decoupling puts ratepayers in the position where they have traded distribution rate certainty for distribution rate uncertainty. By definition, risk averse agents like ratepayers will be worse off under decoupling (even with rate decrease opportunities) since certainty is always higher valued (greater expected utility) relative to risk.[36] Other things being equal, revenue decoupling cannot, over the long run, result in rate decreases since, based upon the Company's position, use per customer will always be decreasing, resulting in a relatively consistent series of rate increases over time. Thus, the shaded promises of decoupling, at best, will result in decreases in household benefits because it has traded a certain for risky outcome; and at worst, is hollow, since usage trends would indicate such an outcome is unlikely to occur over the longer run.

VI. DEFICIENCIES IN THE RATIONALE FOR DECOUPLING

Q. WHAT ARE THE PURPORTED DISINCENTIVES TO UTILITIES TO PROMOTE ENERGY EFFICIENCY?

A. Energy efficiency advocates, as well as many (but not all) utilities, often argue that current regulatory pricing practices discourage utility-sponsored energy efficiency programs. These advocates claim that energy efficiency reduces sales thereby reducing a utility's ability to recover its fixed costs. One of the primary rationales for the Company's revenue decoupling proposal has been to address what it claims is a mismatch between the financial interests of its customers and its shareholders regarding energy efficiency.

Q. HOW DOES REVENUE DECOUPLING ADDRESS THIS PURPORTED DISINCENTIVE?

[36] P.R.G. Layard and A.A. Walters. (1978). *Microeconomic Theory*. New York: McGraw-Hill Book Company, 357.

A. Revenue decoupling removes the relationship between the collection of a utility's revenue requirement and its sales. Under the Company's revenue decoupling approach, changes in sales revenues would be compared with benchmark revenue amounts. The purported public policy goal of revenue decoupling is to make a utility indifferent between making an incremental sale or creating incremental end-use efficiencies.

Q. ARE SALES DECREASES DUE TO ENERGY EFFICIENCY THE ONLY CAUSE OF DIFFERENCES BETWEEN TEST YEAR (ALLOWED) AND ACTUAL REVENUES?

A. No. In fact, utility lost base revenues associated with energy efficiency programs are typically quite small. There are a variety of other reasons why retail natural gas sales and revenues in any given year can differ from the test year amount and these impacts are usually considerably larger than sales losses created by energy efficiency programs. Consider that test year retail sales and revenues in a rate case are usually based upon a "typical" year and as such, are based upon typical factors such as the weather, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year, weather may be colder or warmer than the long-run normal weather trends included in the test year, and other factors may occur in any given year that impact sales differently than what was anticipated in the test year determination. The differences in sales created by weather, the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

Q. HOW DO THE MOTIVATIONS FOR REVENUE DECOUPLING DIFFER BETWEEN ELECTRIC AND NATURAL GAS UTILITIES?

A. Revenue decoupling has attained a new level of interest in recent years for natural gas and electric utilities due to (1) the significant increase in natural gas prices, particularly after 2005, which has impacted overall usage[37] and (2) the significant acceleration of state-driven energy efficiency ("EE") goals and targets. Exhibit DED-15 presents a map that shows EE goals that many states have recently adopted hoping to attain demand reduction levels by as much as 15 to 20 percent by 2015.

Q. ARE NATURAL GAS AND ELECTRIC UTILITIES FACING SIMILAR USAGE TRENDS?

A. No. Natural gas utilities have claimed an additional motivation for promoting revenue decoupling that is associated with changing trends in overall use per customer ("UPC"), particularly declining trends in residential UPC over the past several years. Electric utilities have not been facing similar decreasing UPC trends, and in fact, have seen UPC trends move in opposite directions from those seen in the natural gas industry. The chart in Exhibit DED-16 compares overall U.S. electric and natural gas UPC trends over the past 18 years. While electric UPC has been generally increasing, over this same period, natural gas UPC has been generally decreasing.

Q. HAVE NATURAL GAS UTILITIES SEEN REVENUE AND SALES DECREASES FROM THESE UPC TRENDS?

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[37]Natural gas price increases are also important in power markets since natural gas typically determines the price of energy at the margin in many hours of the day in most regional wholesale power markets.

A. No, in fact total usage and total non-gas distribution revenues have continued to increase for most gas distribution companies. Exhibit DED-17 provides a graph of the historic trends in total use and total estimated non-gas distribution revenues. In each instance, total use and total revenues have been increasing primarily due to significant natural gas customer growth that has occurred over the past several decades. Thus, the claim that these UPC trends are compromising utilities' ability to recover the returns on and of their investment, is highly untenable.

Q. HAVE NATURAL GAS DISTRIBUTION COMPANIES EXPERIENCED CONSIDERABLE LOST REVENUES AS A RESULT OF PAST ENERGY EFFICIENCY EFFORTS?

A. No. Most natural gas utility energy efficiency efforts have represented relatively small shares of their overall retail sales and revenues. As previously discussed, Exhibit DED-2 provided a table of natural gas utilities considered to be leaders in the promotion of energy efficiency. As seen from the table, savings from these energy efficiency programs typically represent relatively small shares of overall revenues.

Q. WHAT FACTORS ARE INFLUENCING CHANGES IN UPC IF ENERGY EFFICIENCY SAVINGS DO NOT ACCOUNT FOR CONSIDERABLE SHARES OF UTILITY REVENUE CHANGES?

A. A number of factors influence sales including weather, income, commodity prices, as well as structural usage changes created by new and more efficient appliance standards. More recently, the recession and its consequences of unemployment and belt tightening have contributed to a reduction in usage by customers. As I noted earlier, natural gas commodity prices have changed dramatically over the past eight years starting during the winter of 2000-2001 and particularly in the aftermath of Hurricanes Katrina and Rita in 2005. These commodity price changes have had considerable impacts on recent changes in total residential use per customer. In fact, as seen in Exhibit DED-16, some of these UPC trends are starting to reverse themselves, despite four to five years of energy efficiency activism, due to considerably lower natural gas commodity prices.

Q. ARE YOU AWARE OF ANY STUDIES THAT HAVE EXAMINED THE IMPACT OF HIGH AND VOLATILE NATURAL GAS PRICES ON RESIDENTIAL NATURAL GAS DEMAND?

A. Yes. The American Gas Association ("AGA") released a study in 2007 that examines residential customer reactions to natural gas prices across the U.S. and in different census regions.[38] The AGA residential natural gas demand study used utility-specific monthly data from 46 different companies across the U.S. There were three reported purposes for conducting this study that included:

- Examining whether or not the trend in declining use per customer (residential) has changed in this higher-priced natural gas environment;
- Developing updated residential price elasticity estimates for the U.S. and each of its nine respective census regions;
- Obtaining estimates of changes in residential use per customer attributable to technology-induced gains in appliance and shell efficiency.

Q. WHAT CONCLUSIONS WERE REACHED IN THE AGA STUDY?

[38] Joutz, F. and Trost, R. An Economic Analysis of Consumer Response to Natural Gas Prices. Prepared for the American Gas Association. March 2007.

A. The AGA study found statistically significant price elasticities nationally and in every region examined. The long run price elasticity of demand on a UPC basis was estimated to be -0.18 nationally.[39] The study noted that the residential price elasticity of demand (on a UPC basis) has remained relatively constant between the periods in which natural gas prices were relatively low (pre-2000) and when they were relatively high (post-2000). The most important conclusion of the study was that well over half of the post-2000 decrease in residential natural gas UPC (57 percent) was attributable to price.[40] Only 43 percent of the decrease in residential UPC was attributable to longer-term structural changes in efficiency and appliance stock turn-over.[41]

Q WHAT CONTROL DOES A UTILITY HAVE OVER SUCH FACTORS AS COMMODITY PRICES, THE ECONOMY, WEATHER, AND TECHNOLOGICAL STANDARDS?

A. Utilities have virtually no control over these factors so the premise that the current regulatory regime creates a throughput incentive is entirely illogical. Consider that utilities have no specific influence on the economy or economic growth, they have no ability to change natural gas commodity prices and can only change distribution rates with the approval of their regulators, cannot control the weather, and have no control over technological trends or innovation. How utilities would encourage more throughput between rate cases is absolutely beyond explanation: utilities simply cannot control customers and customer usage.

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[39] Ibid, p. 5.
[40] Ibid, p. 49.
[41] Ibid, p. 49.

Q. CAN'T UTILITIES PROMOTE RATE STRUCTURES THAT EXPAND USE?

A. Yes, but those declining block rate structures are developed in a fashion that tends to reflect the underlying costs of service and ultimately have to be approved by regulators. Utilities are regulated because they are (1) imbued with the public interest and (2) have natural monopoly cost characteristics (i.e., declining costs). Rates typically reflect these cost characteristics because efficient use (output) decreases overall average costs for all ratepayers. A contraction of efficient use, therefore, can have the ability to raise costs, other things being equal. So, to the extent that rate design promotes use, there is a sound economic and regulatory reason for promoting that use: declining block rate structures are developed for the explicit purpose of creating efficiencies and cost savings for all customers, not the select few that may be participating in a subsidized energy efficiency program.

Q. WHAT ABOUT SALES LOSSES ASSOCIATED WITH THE PROMOTION OF MARKET TRANSFORMATION PROGRAMS?

A. Large and rapid decreases in energy use are not likely to arise from any market transformation program thereby causing potential financial harm for the Company. Education is a long-term proposition and the results of these market transformation programs will likely be embedded (and difficult to separate) from the trend in usage per customer.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS THAT LOST REVENUES SIMPLY WON'T PROVIDE THE APPROPRIATE SIGNALS FOR

UTILITIES TO ENGAGE IN MARKET TRANSFORMATION?

A. I would disagree. CGC, like any other regulated utility in this country, has an obligation to serve its customers in a safe, reliable, and economic fashion. Part of that charge should be informing and educating customers about the appropriate use of utility services that rely heavily upon local, regional, and national natural resources. Failure to responsibly inform customers about any actions that may jeopardize these resources would be, or at least should be, imprudent.

Q. WHAT DOES, OR SHOULD, THE PUBLIC INTEREST STANDARD IMPLY ABOUT INEFFICIENT SALES PROMOTION AND THE PROVISION OF UTILITY SERVICE?

A. Utilities operate in the public interest because they (1) provide basic and necessary customer services and (2) extract and utilize valuable natural resources in the provision of these services (energy, air, water, land) to the public. Public utilities are expected to act and perform in a fashion that is consistent with this responsibility. Intentionally wasting these natural resources, which is the effective premise of the "throughout incentive" suggested by decoupling, is inconsistent with this public interest standard. The promotion of inefficient sales to reward shareholders is simply inconsistent with the underlying public interest principles of close to 100 years of utility regulation. To act in such a fashion would intentionally jeopardize natural resources, unnecessarily increase costs for ratepayers, and prejudice the public interest. If utilities intentionally engage in such inefficient actions, then regulatory commissions ought to consider very stringent penalties, as opposed to incentives, to bring utility actions in line with the public interest.

Q. DO YOU HAVE ANY EXAMPLES OF UTILITIES THAT RECOGNIZE THIS PUBLIC INTEREST REQUIREMENT RELATIVE TO SALES GROWTH AND DECOUPLING?

A. Yes. Georgia Power Company, which is part of one of the largest electric utilities in the United States, noted in its comments on the Georgia State Energy Strategy:

> <u>Decoupling is typically proposed as a solution to a perceived problem that does not exist</u> … The report assumes that under the current scheme of cost-based regulation…there is an ongoing and significant incentive for electric utilities…to grow its sales and a corresponding negative incentive to implement energy efficiency because of lost revenues.
>
> [Our] focus is and has always been on reliable, competitively priced electricity and great service for its customers. <u>[Our company] only implements energy sales initiatives where those initiatives can be shown to help reduce the price of electricity to [our] customers</u>.
>
> [We are] also subject to frequent rate proceedings that ensure that there are not long-term incentives to simply increase sales to drive increased profitability… This has ensured that there is not a long-term benefit to [our] earnings from simply increasing electricity sales, as those additional sales are included when revenues and prices are re-set during the rate proceeding.[42]

More recently, the CEO of Southern Company stated his continued belief that decoupling is not workable for his company .

> I'm reluctant to answer a ever consider kind of question, because I think in these times you always have to be willing to consider anything. But fundamentally, we don't think that the decoupling concept works in our regulatory environment. And fundamentally, I've said I don't particularly like the notion. I think there is good

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[42] Comments of Georgia Power Company on the State Energy Strategy for Georgia. Comment period June 6, 2006 to July 5, 2006, emphasis added.

> reason to keep the cost of the product connected with the use of the product and make sure that our customers are as informed as we can possibly make them about how to use a product and the service efficiently and effectively to control their costs. I like that model a lot better than I like disconnecting what I think ought to go together.[43]

VII. STATE REGULATORY POLICES AND DECOUPLING

Q. DO YOU THINK THE DECOUPLING DEBATE HAS ANY COMMON ATTRIBUTES WITH OTHER PAST POLICY INITIATIVES?

A. Yes, the promotion and adoption of revenue decoupling is perhaps one of the most divisive public policy issues to be debated in public utility regulation in the past twenty years. The only policy debate comparable would be electric retail competition. Any individual suggesting that revenue decoupling will result in some kind of "win-win" between utilities and consumers has clearly not been in tune with the debate, the positions of differing parties in this debate, and the considerable policy and ratemaking issues at stake.

Q. IS REVENUE DECOUPLING A NEW METHOD FOR DEALING WITH CHANGES IN REVENUES RESULTING FROM UTILITY-SPONSORED ENERGY EFFICIENCY PROGRAMS?

A. No. There is nothing "new" about revenue decoupling, which is a policy proposal that dates back to the late 1980s and early 1990s, and was included as a regulatory review requirement in the Energy Policy Act of 1992 ("EPAct 1992"). Past revenue decoupling initiatives were driven primarily by the electric utility industry, and many of the same energy efficiency and environmental advocates

[43] Southern Company (SO), Q2 2009 Earnings Call, July 29, 2009 1:00 pm ET; with CEO David Ratcliffe.

promoting the mechanism today. Most decoupling mechanisms created during this period were eliminated during the electric restructuring process that also began in the early 1990s and accelerated through the better part of the decade.

Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE DECOUPLING CAN LEAD TO SERIOUS PROBLEMS DURING AN ECONOMIC CONTRACTION?

A. Yes, one of the more widely-recognized failures of revenue decoupling occurred in Maine during the early 1990s. The program, known as “ERAM” (“Electric Revenue Adjustment Mechanism”), was put into place for a three-year trial period to encourage Central Maine Power (“CMP”) to promote energy efficiency. The ERAM, like the proposed RPC, had no adjustments for changes in regional activity. The adoption of the ERAM coincided with a recession that resulted in lower sales levels and substantial revenue deferrals. CMP was entitled to recover these deferrals under the provisions of the ERAM mechanism, which by the end of 1992 reached $52 million. Only a very small portion of this amount was attributed to CMP’s conservation efforts as most of the deferral resulted from the economic recession. The ERAM was viewed by many as a mechanism that shielded CMP from the economic impact of the recession rather than furthering the intended energy efficiency and conservation incentives. CMP’s ERAM was terminated on November 30, 1993.[44]

[44] Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability, Maine Public Utilities Commission, Presented to the Utilities and Energy Committee, February 1, 2004.

Q. CAN YOU EXPLAIN THE FEDERAL LEGISLATION THAT THE COMPANY SUGGESTS REQUIRES THE TRA TO IMPLEMENT POLICIES LIKE DECOUPLING?

A. Yes, the American Recovery and Reinvestment Act of 2009 ("ARRA") was passed by Congress and signed into law in early 2009. A large portion of the ARRA was dedicated to promoting energy efficiency and renewable energy. In order to qualify for funds distributed from the ARRA, each state was required to certify that its regulatory policies supported the development of energy efficiency. Specifically, the ARRA required states adopt:

> . . . in appropriate proceedings for each electric and gas utility, with respect to which the State regulatory authority has ratemaking authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide 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.[45]

Q. DID TENNESSEE ADOPT SIMILAR LEGISLATION?

A. Yes. Soon after the passage of the ARRA, the Tennessee Legislature passed Section 65-4-126 of the Tennessee Code Annotated that follows language similar in nature to the ARRA:

> . . . 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

[45] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 § 410(a), 123 Stat. 147 (2009).

efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently..[46]

Q. DO YOU THINK THE ARRA, OR THE TENNESSE STATUTE, REQUIRES THE ADOPTION OF REVENUE DECOUPLING?

A. Not from a policy perspective. On its face, and within the four corners of the policy statements, there are no explicit requirements for revenue decoupling, straight-fixed variable rate design, revenue stabilization plans, performance-based regulation, or any other regulatory policy measure often attributed to either piece of legislation. Further, the ARRA gives state commissions considerable latitude to examine the issue of utility incentives, regulatory structure, and energy efficiency. Assertions that the ARRA requires revenue decoupling, or even suggests that this policy is preferred to traditional regulation, is a misinterpretation of the legislation. In fact, the original language in the House version of the ARRA specifically included requirements and provisions for revenue decoupling, but the National Association of Regulatory Utility Commissioners ("NARUC"), as well as other ratepayer and consumer groups like NASUCA and ELCON, recommended that these requirements be removed from the bill.[47]

[46] Tenn. Code Ann. § 65-4-126.

[47] In Re: Economic stimulus legislation and state utility ratemaking policies. Letter to Congressional Leaders from The National Association of State Utility Consumer Advocates (NASUCA) and The Electricity Consumers Resource Council (ELCON). January 23, 2009. Also see: Testimony of the Honorable Richard E. Morgan, Commissioner, District of Columbia Public Service Commission on Behalf of the National Association of Regulatory Utility Commissioners on "Allocation Policies to Assist Consumers". Before the United States House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and the Environment. April 23, 2009.

Q. DOES TRADITIONAL REGULATION ADDRESS THE KEY COMPONENTS OF THE ARRA AND SECTION 65-4-126 OF THE TENNESSEE CODE ANNOTATED?

A. Yes. Traditional regulation addresses each of the three components including the provision that suggests:

1. Regulators should have a "general" policy that aligns utility incentives with helping customers use energy more efficiently.
2. Regulators should have a "general" policy that allows utilities the timely recovery of their energy efficiency investments.
3. Regulators should have a "general" policy that allows for the timely recovery of earnings associated with cost effective energy efficiency savings.

Q. LET'S TALK ABOUT THE FIRST ARRA REQUIREMENT. DOES CURRENT REGULATION ALIGN UTILITY INCENTIVES WITH HELPING CUSTOMERS USE ENERGY MORE EFFICIENTLY?

A. Yes. Utilities are regulated in the public interest. The goal of current regulation is to develop fair, just, and reasonable rates. Utilities, are given an opportunity to recover their prudently-incurred costs, and a return on and of their prudently-incurred investments if they are found to be providing reliable and economic service. This "regulatory compact" has aligned customer and utility interests in the provision of service for over a century. This general policy is not restricted to just one type of service alone and includes gas procurement, distribution services, customer services, and energy efficiency services.

Q. CAN REVENUE DECOUPLING UNDERMINE THE ALIGNMENT OF THESE INTERESTS?

A. Yes. Revenue decoupling would undermine this positive set of incentives (i.e., profit in return for economic and reliable service) and the alignment of utility and ratepayer interests. Revenue decoupling provides guaranteed revenues, creating incentives for inefficiency and poor service. If utility service is interrupted, revenue decoupling without any corresponding protections, will ensure that a Company has been made whole for those sales losses, minimizing its incentives for speedy service restoration. If customer service is poor, and customers leave for alternative energy sources (like electricity), a decoupled natural gas utility will be made whole for that loss and is held unaccountable for its actions. If a utility's rates are not competitive, and it loses customers to bypass or fuel switching, a decoupled utility will be made whole for the inefficiency. If opportunities to add new loads arises through business relocations or expansions, revenue decoupling discourages active pursuit of those loads since a utility will be made whole with, or without, the new customers. Thus, revenue decoupling does nothing to align customer and utility interests, and does everything to move those interests in opposite directions.

Q LET'S TURN TO THE SECOND ARRA REQUIREMENT. DOES CURRENT REGULATION PROVIDE A GENERAL POLICY THAT ALLOWS FOR THE TIMELY RECOVERY OF ENERGY EFFICIENCY COSTS?

A. Yes. Rate cases and other cost recovery mechanism give utilities the opportunities to recovery their energy efficiency expenditures. Some utility commissions require those costs to be recovered in base rates, while others allow energy efficiency cost recovery tracker mechanisms like the one proposed by the Company. Regardless, either mechanism, both currently available under traditional regulation, gives the utility of timely recovery of energy efficiency costs without the need for revenue decoupling.

Q. LET'S TURN TO THE THIRD ARRA REQUIREMENT. DOES CURRENT REGULATION PROVIDE A GENERAL POLICY THAT ALLOWS FOR THE TIMELY RECOVERY OF EARNINGS ASSOCIATED WITH ENERGY EFFICIENCY SAVINGS?

A. Yes, as I noted before, current regulation has provided utilities with an opportunity to earn a return on and of their prudently-incurred investments for well over a century. This allowance is not set on an asset-specific basis, nor is it restricted to certain types of assets. Utilities get an allowed rate of return that is uniform for all types of capital investments such as distribution mains, transmission mains, compression, regulation, service lines, meters, general plant, and other types of capital investments. The current process does not exclude energy efficiency to the extent that the nature of the investment is capitalized. Further, if earnings were to fall due to energy efficiency investments, utilities are typically allowed to come before a regulatory commission to seek an increase in rates in order to cover those earnings losses.[48]

[48] This assumes that a utility is not under some type of performance, incentive, or formula-based rate plan that includes a "stay-out" provision.

Q. DO YOU AGREE WITH THE ASSERTION THAT REVENUE DECOUPLING WILL ALIGN THE INTERESTS OF THE COMPANY AND ITS CUSTOMERS?

A. No, the Company's suggestion that revenue decoupling will align the interests of the Company and its customers is not correct.[49] Revenue decoupling is being actively debated before various state legislatures and state regulatory commissions and is seen as a divisive issue by some important stakeholder groups. For some groups, like energy efficiency advocates and some utilities, revenue neutrality is seen as a positive regulatory outcome. Other groups, particularly consumer groups, are very concerned about the adoption of revenue decoupling and the implications it may have for customer bills. Two prominent consumer groups have opposed regarding revenue decoupling mechanisms including the Electric Consumers Resource Council ("ELCON") and the National Association of State Utility Consumer Advocates ("NASUCA").

Q. WHAT POSITION HAS ELCON TAKEN ON REVENUE DECOUPLING?

A. ELCON, a large trade association comprised of major industrial customers of natural gas and electricity, issued both a position statement and White Paper strongly opposed to revenue decoupling: a position similar to that taken by most industrial customers in the early 1990s when revenue neutrality mechanisms were initially debated. The White Paper issued by ELCON noted many flaws with revenue decoupling including:

(1) Decoupling promotes mediocrity in the management of a utility;

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[49] Direct Testimony of Steve Lindsey, p 6.

(2) Decoupling shifts significant business risk from shareholders to consumers with only limited opportunities for net increases in consumer benefits;

(3) Decoupling eliminates a utility's financial incentive to support economic development within its franchise area;

(4) Decoupling tends to address "lost revenues" and not the real issue which is "lost profits;"

(5) Sending appropriate price signals is the most important step in promoting energy efficiency; and

(6) Third party, independent delivery of energy efficiency services is a more effective means of addressing incentives.[50]

Q. WHO DOES NASUCA REPRESENT?

A. NASUCA represents the various state-funded Attorneys General, consumer counsels, and consumer advocate agencies charged with representing the interests of all ratepayers in state utility regulatory proceedings.

Q. HAS NASUCA ISSUED A FORMAL POSITION STATEMENT OR RESOLUTION ON REVENUE DECOUPLING?

A. Yes. In 2007, NASUCA passed a resolution stating that it would "continue its long tradition of support for the adoption of effective energy efficiency programs" and "oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases."[51]

Q. HAVE YOU PROVIDED AN ANALYSIS ON THE CURRENT PROGRESS OF REVENUE DECOUPLING ADOPTION AND REJECTION?

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[50] Revenue Decoupling, A Policy Brief of the Electricity Consumers Resource Council. The Electricity Consumers Resource Council, January 2007.

[51] National Association of State Utility Consumer Advocates, NASUCA Energy Conservation and Decoupling Resolution, Resolution 2007-01, June 12, 2007.

A. Yes, Exhibit DED-18 shows the recent activity on revenue decoupling for natural gas utilities across the U.S. Currently, there are 15 states that have adopted revenue decoupling as either a permanent or pilot mechanism for natural gas utilities. These states include Arkansas, California, Colorado, Illinois, Indiana, Maryland, Nevada, New Jersey, North Carolina, Ohio, Oregon, Utah, Virginia, Washington and Wyoming. Another six states have enacted legislation that requires decoupling including Connecticut, Massachusetts, Michigan, Minnesota, New York and Wisconsin. Kansas and Tennessee are currently considering revenue decoupling proposals.

Q. HAVE ANY STATES REJECTED REVENUE DECOUPLING PROPOSALS?

A. Yes, some states have rejected decoupling. In 2009, Rhode Island rejected National Grid's revenue decoupling proposal stating that it "is not persuaded that experimenting with full revenue decoupling is appropriate at this time."[52] Similarly, the Arizona, Iowa and Nebraska commissions have not been convinced that decoupling is necessary. In a generic docket considering decoupling, the Iowa Utilities Board concluded that "Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings."[53] In 2006, the Nebraska Commission recognized the possibilities of increased rates and risk shifting from decoupling:

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[52] Application for a rate change pursuant to R.I.G.L. §§ 39-3-10 AND 39-3-11 of Narragansett Electric d/b/a National Grid. Rhode Island Public Utilities Commission. Docket No. 3943. January 29, 2009.

[53] In re: Inquiry into the effect of reduced usage on rate-regulated natural gas utilities. Iowa Utilities Board. Docket No. NOI-06-1, December 18, 2006.

> 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.[54]

Q. HAS THE TRA MADE ANY FINDINGS ON DECOUPLING OUTSIDE OF ITS RECENT PIEDMONT FINDINGS?

A. Although the TRA has not yet issued a final order on the subject, this issue was discussed in the transcripts of its deliberations in Docket No. 05-00258 concerning the Consumer Advocate's petition for Atmos Energy Corporation to appear and show cause that it was not over-earning. On the subject of Atmos' Customer Utilization Adjustment ("CUA"), as well as other issues, Commissioner Miller filed a written a motion setting forth his proposed resolution to the issues raised in this proceeding. On the subject of the CUA, Commissioner Miller's Motion stated:

> The modification proposed by Atmos to include the Customer Utilization Adjustment, also known as CUA, within the Weather Normalization Audit ("WNA") is a novel approach to lessen inaccuracies that may occur when forecasting revenues/margins for Atmos. It is abundantly clear that the recovery of fixed costs through a volumetric charge can lead to over or under recovery of such costs. The proposed CUA, however, does not correct this problem; rather it removes any incentive for Atmos to control fixed costs. Therefore, I move to deny the Customer Utilization Adjustment.[55]

[54] In the matter of Aquila, Inc. d/b/a Aquila Networks (Aquila) Omaha, seeking individual rate increases for Aquila's Rate Area One, Rate Area Two, and Rate Area Three. Before the Nebraska Public Service Commission. Application No. NG-0041. July 24, 2007.

[55] Director Miller's Motion.

Chairman Kyle and Director Jones both agreed with the motion made by Commissioner Miller.[56] The concerns raised by the TRA in that proceeding are consistent with the ongoing concerns expressed recently in the Piedmont investigation.

Q. HAVE SOME STATES CHANGED THEIR POSITIONS ON REVENUE DECOUPLING?

A. Yes. In New York, the Commission initially rejected a decoupling proposal for Consolidated Edison, but in 2007 it issued an order requiring electric and gas utilities to file proposals for true-up based decoupling mechanisms in ongoing and new rate cases.

Q. HAS REVENUE DECOUPLING LEGISLATION REQUIRED OTHER COMMISSIONS TO CHANGE THEIR PRECEDENT?

A. Yes. In 2006, the Connecticut Department of Public Utility Control ("DPUC") originally ruled strongly against revenue decoupling for its electric and gas utilities and took issue with: (1) the position that decoupling creates incentives for EE; and (2) the degree to which decoupling shifts business risk from a utility to consumers. The DPUC found that:

> …decoupling by itself does not provide an incentive to energy DCs to promote conservation. Rather, in helping to ensure fixed cost recovery, it removes a disincentive for companies to promote conservation. However, it may also shift to ratepayers such normal business risks as lower sales due to economic downturns, weather, new energy efficiency technology, and demand response to price increases. This report discusses mechanisms for various degrees of decoupling ranging from partial to full decoupling. **<u>In general, the</u>**

[56] Docket No., 05-00258, Tr. October 26, 2006, pp. 6-7, 15.

more complete the decoupling, the more business risks are shifted from the energy DCs to the ratepayers.[57]

Q. WHAT HAPPENED AFTERWARDS?

A. In 2007, the Connecticut Legislature enacted the Electricity and Energy Efficiency Act which established very specific requirements for decoupling and required the DPUC to order the state's electric and natural gas distribution companies to decouple their distribution revenues. While the DPUC approved decoupling for United Illuminating soon after the legislation passed, it recently rejected a comparable proposal for Connecticut Natural Gas.

Q. HAVE ANY OTHER STATE COMMISSIONS CHANGED THEIR POSITION DUE TO OPPOSING LEGISLATIVE REQUIREMENTS?

A. Yes. In Michigan, decoupling proposals that were strongly opposed by the Michigan Attorney General were ultimately dropped by both SEMCO and Consumers Energy as part of settlement agreements. However, in October 2008, the Governor signed into law a bill allowing natural gas utilities to request a revenue decoupling plan as long as they are spending at least 0.5 percent of total revenue on energy efficiency programs.[58]

VIII. DECOUPLING AND RISK SHIFTING

Q. WHO TRADITIONALLY BEARS THE RISK OF CHANGES IN SALES REVENUE?

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[57] DPUC Investigation into Decoupling Energy Distribution Company Earnings from Sales, Decision, Connecticut Department of Public Utilities, Docket No. 05-05-09, January 18, 2006, *emphasis added*.

[58] Michigan Public Act No. 295, Approved by the Governor, October 6, 2008.

A. The utility and its shareholders typically bear the risk of revenue and sales differences from the test year for a number of different reasons. First, it is the utility's responsibility to propose a typical year for rate-making purposes. It would not be in a utility's, nor its shareholders' best interest, to propose a test year that was unsupportive of what management believed was required to recover costs and earn its allowed return. Second, a utility's allowed rate of return, like that of any other business, includes some premium for the business risk inherent in the industry in which it operates.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

A. Under decoupling, if revenues fall due to a contraction in the economy, customers will be required to make the utility whole for those revenue shortfalls. Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times or alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risks of these economic contractions, just like many other types of businesses and industries.

Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?

A. As noted earlier in the summary of the recent AGA study, when natural gas prices increase, they can have a direct impact on natural gas usage. Holding other factors constant, natural gas commodity price increases are typically translated into higher overall average prices seen by ratepayers on their total bills. Under the Company's decoupling proposal, it will be made whole for any natural gas price-induced reductions in UPC. Maintaining a revenue decoupling mechanism like that proposed by the Company, without any corresponding adjustment for this shift in revenue recovery risk, results in rates that are inconsistent with the fair, just, and reasonable standards of traditional utility regulation.

Q. HAS THE CONNECTICUT DPUC ISSUED ANY OTHER DECISIONS REGARDING DECOUPLING AND RISK?

A. Yes. Notwithstanding recent legislation allowing revenue decoupling, the DPUC recently rejected, once again, a decoupling proposal offered by Connecticut Natural Gas and found:

> Full decoupling compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conservation. Clearly, the very large potential risk of revenue instability is shifted from the Company to customers. If the Company were to purchase an insurance instrument to guarantee [sic] distribution revenues, the insurer would expect compensation and the Company would expect to make payment for the transfer of risk. The Company's decoupling proposal thrusts customers into the role of insurer without proffering compensation. By reviewing the level of compensation customers would require to breakeven under decoupling, the Department concluded that the requisite reduction in ROE needed as compensation would prove too draconian and actually impede the Company's ability to attract capital. The Company's own calculation shows that a 10% change in weather (HDDs) alone translates into a $4 million change in revenue. Add to this a continuing loss in UPC as predicted by the Company plus the uncertainty of a faltering economy and customers, conservatively, are at risk for $5 to $7 million of annual revenue shortfall. It will require a 100 basis point reduction in ROE (approximately a $3.8 million reduction in revenue) to provide customers with weather-only compensation, without anything

> additional. While decoupling can be expected, *a priori*, to reduce the frequency of rate applications and associated expense, the Company has not proffered any stay-out proposal. The enlarged conservation expenditures that the Company points to as the decoupling quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further. The Company's decoupling proposal guarantees a revenue stream free of customer compensation while holding open the freedom to file a rate application at will. The Company's decoupling proposal is denied.[59]

Q. WHAT ABOUT THE ARIZONA FINDINGS REGARDING REVENUE DECOUPLING?

A. In 2005, the Arizona Corporation Commission ("ACC"), in evaluating a proposal offered by Southwest Gas Company noted that:

> [t]he 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 public policy requires such a result . . .[60]

Last year (2008), Southwest proposed another decoupling mechanism and in its decision the ACC found:

> [i]t 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.[61]

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[59] Application of Connecticut Natural Gas Corporation for a Rate Case; Docket No. 08-06-12, Decision, June 30, 2009.

[60] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, Docket No. G-01551A-04-0876; Decision No. 68487, February 23, 2006.

[61] In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona, Docket No. G-01551A-07-0504; Decision No. 70665, Arizona Corporation Commission, December 24, 2008.

Q. WHAT HAS THE NEW HAMPSHIRE COMMISSION FOUND ON THIS ISSUE?

A. The New Hampshire Commission determined that decoupling could inappropriately shift risks onto customers.

> 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.[62]

IX. IMPLEMENTATION DEFICIENCIES IN THE DECOUPLING TRACKER

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE DECOUPLING TRACKER IN GREATER DETAIL?

A. The Company's proposed AUA rider is a type of revenue per customer ("RPC") approach to decoupling that compares actual RPC in any given month to an allowed RPC level determined in this proceeding. The Company proposes that any deficiency (or surplus) that arises from this difference (between actual and allowed RPC) should be multiplied by actual customers in order to arrive at a total deficiency (or surplus) for recovery (or credit). The Company then proposes to divide this deficiency (surplus) from projected sales (throughput) in order to arrive at a volumetric surcharge (or credit) that is applied to customer bills. The

[62] Energy Efficiency Rate Mechanisms Order Resolving Investigation, New Hampshire Public Utilities Commission, DE 07-064; Order No. 24,934, January 16, 2009.

Company is proposing to apply this rider to the residential (R1) and commercial (C1 and C2) classes, as well as the transportation (T3) class.

Q. CAN YOU EXPLAIN THE COMPANY'S PROPOSED "CALCULATION" AND "RECONCILATION" PERIODS?

A. Yes. The Company has structured its AUA to be calculated on an annual basis with usage and customer data from the 12 months ending each April 30 (the "calculation period"). The resulting AUA rate will be applied to customer bills for a twelve month period beginning July 1 of each year (the "recovery period").

Q. ARE THERE ANY IMPLEMENTATION PROBLEMS WITH THE COMPANY'S PROPOSED DECOUPLING MECHANISM?

A. Yes, there are three implementation problems with the Company's proposal. The first implementation problem is the Company's proposal to eliminate the weather adjustment mechanism and to use the AUA as a composite revenue true-up mechanism. The second implementation problem rests with the Company's proposal to include transportation customers in the decoupling proposal. The third implementation problem with the Company's proposal is the use of actual, as opposed to test year, customers.

Q. WHY WOULD EXCLUDING THE WEATHER NORMALIZATION CLAUSE BE A PROBLEM?

A. The creation of a composite revenue tracker is likely to be confusing to customers and also creates an opportunity for permanency that the TRA should reject. For instance, Piedmont, in its recent decoupling application, explicitly separated the two mechanisms due to the customer confusion issues that were raised in its North Carolina program. Piedmont acknowledged a shortcoming of this combined approach by observing that the North Carolina mechanism is in "…consistent need to estimate the weather-sensitive portion versus the energy efficiency portion [separately]."[63] According to Piedmont the Weather Normalization Adjustment in Tennessee, in place since 1991, will provide this important weather-related information in a framework that is based upon a proven calculation that is audited annually by the TRA.[64] The creation of the two mechanisms also creates an opportunity for policy inertia. For instance, removing decoupling, at some future date, should it prove to not have a significant impact on the delivery of cost-effective energy efficiency, will likely be difficult given its interaction as a weather adjustment mechanism. At minimum, it is likely to be confusing to ratepayers by the potential switching back and forth between tracker mechanisms.

Q. SHOULD TRANSPORTATION CUSTOMERS BE INCLUDED IN EITHER THE DECOUPLING MECHANISM OR THE ENERGY EFFICIENCY PROGRAM?

A. No. Retail ratepayers should not be subsidizing programs for customers that are taking commodity service from a third party provider. In addition, transportation customers, seeking competitive service, should not be burdened with the cost responsibility of programs that they have no interest, or responsibility, in promoting. As noted earlier, the RIM test revealed that non-participants will receive no quantifiable benefits from the Company's energy

[63] Response to TRA Data Request 2-5, Docket No. 09-00104.
[64] Ibid.

efficiency program. It would be equally egregious to then apply a surcharge to a class of customers not eligible for these programs, and are seeking to attain competitive commodity service opportunities elsewhere. Such an approach is likely to be non-competitive.

Q. DOES THE COMPANY'S DECOUPLING MECHANISM ALLOW IT TO INCREASE REVENUES DUE TO CUSTOMER GROWTH?

A. Yes, the Company's proposal would allow it to keep the revenues associated with customer growth in the annual true-up process. Thus, rather than being a mechanism that is limited to assisting in the recovery of fixed costs, the Company's proposal is something more: it allows the Company to increase its revenues outside of a rate case on a forward going basis. The Company claims, but provides no evidence, that this is necessary since, supposedly, the additional of new customers is a:

> …significant cost driver on CGC's system. Specifically, the addition of new customers entails substantial capital expenditures that would not be made without retention of incremental base revenues by CGC. This is accomplished through the per-customer approach.[65]

Q. HAS THE COMPANY PROVIDED ANY RELIABLE EVIDENCE THAT ITS INCREMENTAL COST OF SERVING NEW RESIDENTIAL CUSTOMERS IS HIGHER THAN WHAT IS IN RATES?

A. No. The Company bases its support for earning potentially millions of revenues on a forward-going basis exclusively on "knowledge and experience" of the Company's expert as opposed to any definitive empirical analysis of the cost

[65] Direct Testimony of Daniel P. Yardley, pp. 30-31.

differences between serving new and existing customers.[66] The Company has provided virtually no quantitative support that the embedded cost of serving new customers, which is already included in rates, is greater than the incremental cost of adding a new customer. The Company fails to acknowledge that its rates already include the average cost of developing mains, services, meters and regulators for its customers (among other cost components). The real issue here is not that these customers impose a cost, since they do: the issue is do these customers impose an incremental cost that is greater than the average already included in rates.

Q. DID THE COMPANY ATTEMPT TO PROVIDE ADDITIONAL INFORMATION SUPPORTING ITS CONTENTION?

A. Yes, that information was provided in Response to CAPD Question 195, Attachment 195-1 and has been summarized in Exhibit DED-19. The request asked for all of the detailed workpapers and support documentation that served as the basis for the Company's calculations. To date, the Company has not provided the support information behind these cost representations, so I reserve the right to amend my testimony at a later date once this previously-requested information becomes available.

Q. DO ANY ANAMOLIES STAND OUT IN THE DATA YOU HAVE RECEIVED TO DATE?

A. Yes. The Company's analysis provides a comparison of the difference between the incremental and embedded cost of serving new customers. The cost components provided included meters, mains, service lines, regulators, and

[66] Response to CAPD Question 109.

"other." The differences between service lines (incremental to embedded) are minimal and there are no differences between the cost of new and embedded regulators. There is a credit item for new customers for $180 that is undefined, and the largest single cost difference between the two series is associated with meters where a $344 difference between the embedded cost and actual costs. The Company provided no information regarding the source of this data, the age of this data, the customer classes to which it applies, or any explanation of the credit for "other" costs for new customers of ($180). There is no data here to suggest what has caused the increased cost of serving new customers.

X. POLICY ALTERNATIVES: LOST BASE REVENUES

Q. HOW WOULD A LOST BASE REVENUE APPROACH WORK?

A. Under this approach, the Company's ability to recover lost base revenues should be based upon actual savings achieved through its proposed energy efficiency programs. For instance, the Company anticipates that its High Efficiency Gas Water Heater program will achieve 45,000 therms in savings per year. Lost base revenues associated with the program can be estimated as $12,150 per year assuming (a) the Company attains its estimated participation and savings rate and (b) has an average base rate of $0.27 therms. Under this approach, lost revenue recovery is restricted to specific energy efficiency-created changes in sales and not a broader measure of sales loss (like decoupling) that could result from a variety of factors, most of which are beyond the utility's control and its efforts at energy efficiency.

Q. HISTORICALLY, WHAT APPEARS TO BE THE BIGGEST REPORTED DIFFICULTY ASSOCIATED WITH LOST REVENUE MECHANISMS?

A. Lost revenues are simply the product of average utility base rates and the actual savings attained by the DSM program. Since the average utility base rate is regulated and known, the fundamental challenge in estimating lost revenues is measuring and verifying the actual amount of savings.

Q. HOW DOES THE ACCOUNTABILITY ASSOCIATED WITH LOST REVENUES ENHANCE REGULATORS' CONFIDENCE IN ENERGY EFFICIENCY?

A. A lost revenue approach directly ties a utility's incentive to promote energy efficiency to actual performance by linking lost revenue recovery to achievement of energy efficiency goals. As such, a lost revenue approach can be thought of as a type of performance-based regulation since it is the utility's performance that defines its ability to recover revenues associated with energy efficiency-created sales losses. Tying a utility's incentive to accurate measurement gives the Authority, and other stakeholders, increased confidence that (1) the revenues being recovered by utilities are based upon verifiable achieved savings and (2) the costs incurred for DSM program development and implementation are tied to verifiable savings, thereby justifying ratepayers' investment in these programs.

XI. POLICY ALTERNATIVES: PERFORMANCE-BASED APPROACH

Q. WHAT TYPES OF PERFORMANCE-BASED OPTIONS ARE AVAILABLE TO THE TRA?

A. Three options the TRA could consider include:

- An performance-based approach that would base the target goals on an achieved benefit/cost ("B/C") ratio.
- An performance-based approach that offers rewards for reaching a forecasted level of total natural gas savings.
- An performance-based approach that creates an earnings/sharing mechanism offering earnings rewards for superior energy efficiency performance and penalties for sub-par energy efficiency performance.

Q. WOULD YOU PLEASE DISCUSS THE FIRST PERFORMANCE-BASED ALTERNATIVE?

A. The first alternative is an performance-based mechanism that would be based on an achieved B/C ratio for the Company's energy efficiency programs. Here, a target or benchmark B/C ratio would be established and could be set by the estimated B/C ratios included in the Company's filing. A dead-band would be established around this ratio within which results in no penalties or rewards. Exceptional performance outside of the dead-band would be rewarded on some fixed dollar per Dth saved. Sub-standard performance, where the B/C ratio falls below the lower end of the dead-band, would be penalized. A series of blocks could also be established (though not required) that would increase the fixed incentive amount as higher levels of efficiency are reached.

Q. HAVE ANY STATES ADOPTED A MECHANISM SIMILAR TO THIS?

A. Yes. In New Hampshire all programs (including new market transformation initiatives) are screened using a cost-effectiveness test. A cost-effectiveness incentive is awarded for programs that achieve a B/C ratio of 1.0 or higher. In approving this incentive, the New Hampshire Commission stated:

> The utility must demonstrate that the program for which it seeks incentive payments offers customers extraordinary benefits and will enhance the move toward either non-subsidized DSM programs or market-based energy efficiency. These benefits should be over and above what would accrue to ratepayers with prudent utility management.[67]

Q. CAN YOU EXPLAIN THE SECOND PERFORMANCE-BASED ALTERNATIVE?

A. The second alternative is a more traditional DSM performance-based plan. Here a fixed target level of savings (in Dth) is established for the baseline. Again, a dead-band would be set around some target savings level with rewards for achieved savings outside the band, and penalties for achieved savings under the band. A series of blocks could also be established (though not required) that would increase the fixed incentive amount as higher levels of savings are reached. Incentive amounts, bands, and targets would have to be established once the Company provides its two-year portfolio of proposed programs.

Q. HAVE ANY OTHER STATES UTILIZED MECHANISMS SIMILAR TO THE TWO YOU JUST DESCRIBED?

A. Yes and some of these have been highlighted in Exhibit DED-20. In Colorado for example, if a utility achieves at least 80 percent of its savings goals, it is eligible for a bonus on its DSM cost recovery. The bonus is a percentage of the net economic benefits resulting from the DSM plan and is correlated with the

[67] Energy Efficiency Programs. New Hampshire Public Utilities Commission, Order Establishing Guidelines for Post-Competition Energy Efficiency Programs, Order No. 23,574. November 1, 2000

utility's performance relative to an approved savings target (Dth per dollar spent).[68]

Q. DO ANY OF THESE PROGRAMS INCLUDE PENALTIES?

A. Cascade Natural Gas Company has a pilot decoupling plan in Washington State, with a penalty mechanism for failure to meet certain annual energy savings thresholds. The penalty mechanism was a requirement of the commission for its approval of a proposed settlement of the utility's request. The WUTC stated:

> 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. [69]

Q. WHAT OTHER STATES HAVE SIMILAR PERFORMANCE-BASED MECHANISMS?

A. As depicted on Exhibit DED-20, several states have adopted a variety of different incentive mechanisms including California, Rhode Island, and Minnesota.

Q. HOW DOES THE CALIFORNIA PROGRAM WORK?

A. California has utilized a succession of incentive mechanisms over the years. Recently, energy efficiency incentive mechanisms were developed that include energy efficiency goals and a risk/reward incentive mechanism ("RRIM").

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[68] In the matter of the proposed rules regarding natural gas demand-side management, pursuant to House Bill 07-1037, Enacted as ß40-3.2-103, Colorado Public Utilities Commission, Decision No. C08-0248; Docket No. 07R-371G, March 5, 2008, Adopted; March 7, 2008, Mailed.

[69] Washington Utilities and Transportation Commission, Docket UG-060256, Order 05, January 12, 2007.

The RRIM is an incentive mechanism designed to align shareholder and consumer interests. It "provides both a meaningful level of shareholder earnings and a return on ratepayers' investment in energy efficiency." [70]

Q. HOW DOES THE RHODE ISLAND MECHANISM WORK?

A. In Rhode Island, National Grid's threshold performance level for energy savings by sector is 60 percent of annual savings. This must be attained to earn the incentive related to achieving energy savings in the sector. Currently there are five performance metrics each with goals that must be attained in order to earn an incentive. The shareholder incentive mechanism consists of two components: 1) five performance-based metrics and 2) kWh savings targets by sector. The incentive earning for energy savings is capped at 125 percent of the target incentive amount. The incentive earnings for achieving performance metrics is capped at $100,000 ($20,000 for each metric).[71]

Q. WHAT ABOUT THE MINNESOTA PROGRAM YOU REFERENCED EARLIER?

A. In Minnesota, incentives are awarded based upon a finding that utility expenditures have resulted in net ratepayer benefits and only a portion of such net ratepayer benefits are awarded to the utility.[72]

[70] Order Instituting Rulemaking to Examine the Commission's Energy Efficiency Risk/Reward Incentive Mechanism. California Public Utilities Commission, Rulemaking 09-01-019, February 4, 2009.

[71] National Grid Least Cost Procurement. Rhode Island Public Utilities Commission, Docket No. 3931, April 17, 2009.

[72] In the Matter of Requests to Continue Demand-Side Management Financial Incentives Beyond 1998. Minnesota Public Utilities Commission, Docket No. E, G-999/CI-98-1759, April 2000.

Q. WOULD YOU DESCRIBE THE THIRD PERFORMANCE-BASED ALTERNATIVE?

A. Yes. Under the third alternative, the TRA could adopt a broad revenue stabilization/earnings sharing mechanism that would create a positive, performance-based approach to (a) the Company's overall operations and (b) its pursuit of energy efficiency. Under such a plan, the level of earnings shared between ratepayers and shareholders could be tied directly to the success of the Company's energy efficiency programs. The greater the program savings, the larger the sharing percentage that would be attributable to the Company's shareholders.

XII. POLICY ALTERNATIVES: MODIFIED REVENUE DECOUPLING

Q. DO YOU HAVE ANY ALTERNATIVE REVENUE DECOUPLING RECOMMENDATIONS

A. Yes, if the TRA decides to move forward with revenue decoupling, I recommend that it choose between one of two options which I will generally refer to as: (1) the "New Jersey Option;" and (2) the "Washington Option." Both forms of revenue decoupling incorporate positive risk mitigating characteristics that decoupling revenue from sales brings, but do so in a fashion that is tied to the energy efficiency efforts and achieved savings level and shun the notion of guaranteed revenue recovery and risk shifting.

Q. WOULD YOU PLEASE DISCUSS THE NEW JERSEY OPTION?

A. Yes. New Jersey's revenue decoupling program is referred to as the Conservation Incentive Program ("CIP"). The program was originally adopted as the result of a settlement in 2006 for South Jersey Gas Company ("SJG") and New Jersey Natural Gas Company ("NJNG"). The program was recently extended for an additional three year period ending 2013.[73] The program is unique since it ties weather-adjusted margin recovery to upstream natural gas savings attained in the PGA. Here, upstream savings are those associated with: (a) capacity release; (b) reductions in capacity purchases; and (c) reductions in the average cost of purchased gas. The program effectively ties downstream (downstream of the city gate) natural gas savings to those attained upstream. Under such an approach, difficult to prove assertions about "lost fixed distribution cost recovery" become more easily verifiable since a loss of capacity upstream cannot be attained without some type of loss downstream. The program effectively "recouples" performance and revenue rewards for a utility since margin deferrals are not recovered unless they are matched with savings.

Q. DO YOU THINK THE NEW JERSEY APPROACH ADDRESSES MANY OF THE CONCERNS EXPRESSED BY THE VIRGINIA CORPORATION COMMISSION?

A. Yes. Recall that the VSCC has had two concerns with its decoupling mechanism. The first is that the mechanism allowed utilities to recover margins in excess of those associated with its energy efficiency efforts. The second was that energy efficiency programs had the unattractive feature of creating very little savings for non-participating customers. The New Jersey approach solves both of those problems since the program ensures that a utility is not made whole for

[73] New Jersey Board of Public Utilities. Docket Nos. GR0512019 and GR0512020. Final Order. January 21, 2010.

revenues greater that the energy efficiency savings associated with its efforts. Second, and more importantly, non-participating customers attain benefits of funding energy efficiency programs through lower PGA rates. Such an approach is clearly more beneficial, and more consistent with traditional regulation, than the RPC approaches proposed by the Company, as well as many other regulated utilities around the country.

Q. CAN YOU GENERALLY EXPLAIN HOW THE NEW JERSEY CIP WORKS?

A. Yes. Like traditional decoupling plans, the New Jersey CIP starts with base levels of use per customer and revenues (margins) per customer for earnings recovery purposes. The true-up process, like the one proposed by the Company, is done on an annual basis. Utilities are required to show both the changes in their weather-adjusted margins per customer in addition to the gas cost savings that have acquired during the reporting period. Utilities are allowed to recover the full amount of their CIP deferral if the amount is equal to, or less than the gas savings acquired for customer during the same time period. If the CIP is deferral is greater than the gas savings attained in the reporting period, those amounts can be carried over for future eligibility up to three years. Any CIP carry-over deferrals that are not matched with gas cost savings by the end of the three year review period are not eligible for recovery.

Q. HOW IS THE RISK SHIFTING NATURE OF THESE PROGRAMS HANDLED?

A. Utilities are required to cover the full costs of their energy efficiency efforts up to the amounts prescribed by the BPU, below the line: in other words, shareholders are required to pick up the costs of these programs. If the utility fails to spend the amounts required by the Order, the deficiency is carried over until the next year. However, deficiencies cannot be avoided: if a utility fails to spend what it is required at the end of the three year review period, it will have to credit the difference to ratepayers.

Q. WHAT ARE YOUR RECOMMENDATIONS SHOULD THE TRA DECIDE TO PURSUE A POLICY COMPARABLE TO NEW JERSEY'S CIP?

A. The TRA should direct the Company to make a separate filing after the conclusion of this proceeding to develop a plan that is consistent with the components of the New Jersey Department of Public Utilities ("DPU") most recent order extending the CIP program. The program should be modified, where appropriate, for unique characteristics of the Company's service territory, any unique operational considerations, and Tennessee regulatory policy.

Q. WOULD YOU PLEASE DISCUSS THE WASHINGTON PLAN?

A. Yes. The Washington Utilities and Transportation Commission ("WUTC") has had back-and-forth experience with revenue decoupling over the past twenty years. In the early 1990s, Puget Sound Energy had a revenue decoupling mechanism only to see the mechanism removed due to lack of stakeholder support in 1996. Revenue decoupling was not examined again until 2005 when the WUTC held a decoupling workshop and found the issue so nuanced that it deferred any decisions on the matter to utility-specific requests rather than a rulemaking. In the following year, however, the WUTC rejected two separate requests for decoupling from PacifiCorp and Puget Sound Energy. Later in 2006, however, the WUTC approved a decoupling pilot program for Cascade, and a year later Avista.

Q. WERE THERE ANY SPECIAL PROVISIONS IN THE AVISTA DECOUPLING APPROVAL?

A. Yes. Avista's revenue decoupling plan that was accepted by the WUTC with a number of modifications: most of which included a number of important ratepayer protections.[74] Two aspects of the Avista decoupling decision, however, stand out. The first was the requirement that Avista's decoupling balance recoveries be capped at 90 percent of the total deferrals, and actual recoveries of those deferrals be tied to specific savings targets established from its Integrated Resource Plan. The second was that the program would be approved in a pilot basis with a third-party independent review in order to ascertain the merits of the decoupling program and the impact it had on supporting energy efficiency investments.

Q. WHAT IS THE STATUS OF THE AVISTA DECOUPLING MECHANISM?

A. Over the past year, the WUTC has conducted an independent third party analysis of Avista's revenue decoupling plan as part of its rate case filing. Interestingly, this is the first independent decoupling review that has been done by an outside consulting firm not commonly associated with a public utility client

[74] In the Matter of the Petition of Avista Corporation, d/b/a Avista Utilities for an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism. Washington Utilities and Transportation Commission, Docket UG-060518, Order 04, February 1, 2007.

base. The outside consultant was not allowed to "draw conclusion, make recommendations, or otherwise determine whether conservation increased as a result of implementing decoupling."[75] All parties were given the opportunity to file testimony, and offer expert opinions on the decoupling experiment's results, as well as the findings of the outside consultant. On December 22, 2009, the WUTC issued its decision in Avista matter and made a number of important change to its revenue decoupling mechanism.

Q. WHAT DID THE WUTC FIND?

A. The WUTC found that decoupling appeared to stimulate energy efficiency investments but noted, much like the Virginia State Corporation Commission, that the mechanism made the utility considerably more than whole from lost margins associated with energy efficiency. Most of the parties to the proceeding agreed that decoupling created greater than necessary revenue recoveries for the utility. Even Avista, the utility, requested lowering the recovery amounts from 90 percent of the deferrals to 70 percent. The WUTC, in its ruling, capped decoupling recoveries to 45 percent of the deferrals (down from the prior allowed amount of 90 percent), and set a sliding scale for recovery based on achieved energy efficiency savings. The old recovery scale (capped at 90 percent), the new recovery scale (capped at 45 percent), and my recommendations for a similar scale for CGC should the TRA decide to adopt a Washington-style mechanism, has been provided in Exhibit DED-21. I recommend that if the TRA move

[75] Docket 090134 and UG 090135, consolidated. *Washington Utilities and Transportation Commission v. Avista Corporation, d./b./a. Avista Utilities*. Order 10: Final Order Rejecting Tariff Filling; Approving and Adopting Multi-Party Partial Settlement Stimulation; Deferring Lancaster Costs; Extending Decoupling Mechanism; Authorizing Tariff Filing; and Requiring Compliance Filing, December 22, 2009. Final Order at 261.

forward with this type of mechanism, it adopt a 24% cap that decreases based upon the Company's shortfalls at reaching the defined energy efficiency targets.

Q. SHOULDN'T REVENUE DECOUPLING MAKE A UTILITY WHOLE FOR ALL REVENUE LOSSES?

A. No, and while many utilities have attempted to make this argument under the rubric of "new traditional regulation" or some other euphemism, such policies tend to be entirely contrary to the approaches most regulatory commissions that have adopted revenue decoupling to promote energy efficiency, not utility revenue stability. The WUTC was very clear in noting this in its recent order when the subject arose:

> The Company argues that its decoupling mechanism is necessary to allow the recovery of fixed costs approved in the most recent general rate case. <u>We disagree that decoupling's purpose is so broad</u>. The regulatory construct for decoupling in Washington has centered on the utility's performance relative to consideration….<u>We seek to avoid guaranteed recovery of lost margin that would occur should lost margin from other causes be included in the mechanism</u>.[76]

Q. DID THE WUTC ORDER END ON A POSITIVE NOTE FOR REVENUE DECOUPLING?

A. Not entirely. While the WUTC clearly acknowledged the increase in energy efficiency spending that resulted from revenue decoupling, it expressed, what appears to be, some frustration with the decisiveness and complexity of the process:

> We note that decoupling is but one method of supporting conservation, and we encourage the Company and parties to consider alternatives that avoid the mechanism's inherent

[76] Ibid., p. 291.

complications while accomplishing the objectives we set forth herein.[77]

Q. IN THE PAST, YOU HAVE PROPOSED RATEPAYER PROTECTION MECHANISMS THAT ARE MORE COMPARABLE TO THE APPROACH USED IN COLORADO. CAN YOU PLEASE EXPLAIN WHY YOU HAVE NOT OFFERED THAT APPROACH IN THIS PROCEEDING?

A. Yes. The Colorado approach, which caps revenue recoveries to a level consistent with the five year average change in UPC is still an approach that is preferable to an unadjusted RPC methodology like the Company's. However, over the past several months, a number of early-adopting decoupling states have released the results of their reviews of their respective decoupling mechanisms. These reviews have clearly highlighted the fact that over-recovery of revenues is a significant problem with revenue decoupling that needs to be addressed, and controlled, if revenue decoupling is to be adopted. While the Colorado approach has merits, and can be adopted, it still rests on a weak and imperfect relationship between changes in use and energy efficiency efforts. While the mechanism serves to reduce overall ratepayer risk, it could still lead to utility over-recoveries. Thus, a mechanism like New Jersey's CIP, that ties recoveries to gas cost savings, or one like Washington, that ties recoveries to direct estimates of efficiency-created lost base revenues, may be preferable. The key policy component in the development of any revenue decoupling approach is to "re-couple" performance to revenue recovery.

[77] Ibid., p. 309.

XIII. POLICY ALTERNATIVES: RATEPAYER PROTECTIONS

Q. IF THE TRA ADOPTS SOME FORM OF DECOUPLING, DO YOU RECOMMEND ANY GENERIC RATEPAYER PROTECTIONS GO ALONG WITH THIS PROGRAM?

A. Yes. If the TRA approves either form of revenue decoupling (i.e, New Jersey approach or Washington approach), I recommend that it include strong incremental energy efficiency goals for the Company that should be examined at the end of a no more than three-year fixed term for the mechanism. The regulatory review at the end of the fixed period should be clearly defined and the TRA should set a regulatory presumption that the decoupling mechanism will be repealed thereafter the fixed number of years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

Q. WHY ARE YOU RECOMMENDING NO MORE THAN A THREE-YEAR REVIEW PERIOD?

A. A three-year review period is similar to the time periods that have recently been accepted in other states approving revenue decoupling proposals, particularly on a pilot basis. Three years seems to be a long enough period to evaluate meaningful changes in utility promotion of energy efficiency and will not be so long as to allow unanticipated consequences from becoming unmanageable.

Q. WHAT REVIEW CRITERIA SHOULD THE TRA INCLUDE IN THIS DECOUPLING REVIEW PROCESS?

A. The TRA should consider adopting a host of review criteria in its evaluation process that are similar to those adopted in other states. Review criteria could fit into four general categories that would include: (1) an energy efficiency review; (2) a revenue deferrals and collections review; (3) a customer usage analysis; and (4) other review criteria that are defined by the Authority, the Company and other stakeholders.

Q. WHAT TYPES OF CRITERIA SHOULD BE EVALUATED IN THE DECOUPLING REVIEW?

A. A review of the Company's pre- and post-decoupling energy efficiency activities is important in understanding the role that revenue decoupling plays in removing the purported disincentive in promoting energy efficiency. Some of the potential areas of review should include at least:

- A comparison of pre- and post decoupling energy efficiency performance primarily focused on program participation and energy savings. Goals should be set and the Company's ability to attain these goals should be monitored.
- An analysis of the scope, magnitude, and innovation with which the Company is promoting energy efficiency.
- An analysis of the incremental energy efficiency program offerings and/or expansions.
- An analysis of the changes in the avoided costs impacting energy efficiency program participation and savings.
- An analysis of energy efficiency expenditures per program.

- An analysis of the breadth of energy efficiency program offerings across various customer classes.
- A comparison of actual energy efficiency savings to those included in the Company's long run planning process.

Q. SHOULD THE TRA REVIEW THE COMPANY'S REVENUE DEFERRAL AND COLLECTION EXPERIENCE?

A. Yes. Some of the areas of analysis in this category of review should include, but should not be limited to:

- An analysis of monthly, seasonal, annual, and cumulative revenue deferrals and balances.
- An analysis of any changes made to the deferral calculations.
- Comparison of estimated deferrals to those suggested in the rate case.
- An analysis of the potential impact of deferrals on earnings and overall returns.
- An analysis of the bill impacts associated with the decoupling mechanism.
- An analysis of the interest or carrying charges associated with the deferrals.
- An analysis of the actual direct lost margin associated with the Company's total and incremental DSM efforts.

Q. SHOULD OBSERVATIONS ON CUSTOMER USAGE TRENDS AND PERCEPTIONS BE OBSERVED AS WELL?

A. Yes. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

Q. ARE THERE ANY ADDITIONAL CRITERIA YOU WOULD RECOMMEND INCLUDING?

A. The TRA could include other acceptable criteria offered by the Company and other stakeholder groups in its revenue decoupling review. Two additional analyses that may not fit neatly into the categories defined above, but may be nonetheless equally important, could include:

- The degree in which the Company's corporate culture regarding the promotion of energy efficiency has meaningfully changed as a result of the adoption of revenue decoupling.
- An analysis of financial market perceptions of the Company's revenue decoupling mechanism and its potential impact on earnings.

XIV. INFRASTRUCTURE REPLACEMENT AND DECOUPLING

Q. IS THE COMPANY PROPOSING AN INFRASTRUCTURE COST RECOVERY RIDER IN THIS PROCEEDING?

A No. In its last rate case, the Company proposed a cast iron and bare steel replacement cost rider (or generally, "infrastructure cost recovery rider"). The proposal was excluded from the settlement agreement in the last case. The Company notes that as part of the settlement, it did commit to replace 21 miles of pipe by the end of 2010. In addition, the Company notes that it has developed a ten year infrastructure replacement plan that will include, in total, the replacement of 80 miles of pipeline over a 14 year period, inclusive of the 21 miles already replaced.

Q. WHAT DOES THIS HAVE TO DO WITH REVENUE DECOUPLING?

A. Nothing, but the Company is attempting to tie the approval of its proposed decoupling tracker to its proposed infrastructure replacement activities. Decoupling trackers are usually implemented to remove negative disincentives for energy efficiency measures and, if developed appropriately, should have nothing to do with other regulatory issues, like pipeline replacement. The Company, however, is attempting to cast a wide net with its decoupling tracker proposal by noting that if the decoupling tracker is approved, it will presumably alleviate the need for a future tracker mechanism.

Q. HOW DOES THE COMPANY ATTEMPT TO TIE THESE TWO CONCEPTS?

A. The Company notes that pipeline replacement activities are non-revenue generating. In addition, these investments will increase plant in service (rate base) and the return, taxes, and depreciation expenses commonly associated with new investments. Both assertions are correct and consistent with typical regulatory accounting. What is not entirely correct, or is at least questionable, is the subsequent assertion made by the Company that if revenue decoupling were not approved, it would somehow need to come in for repeated rate cases in order to recover the costs of these replacement activities. This assertion is incorrect since:

- The scope of these proposed investments, on an annual average basis, is relatively small and unlikely to lead to any financial deterioration in the Company's earnings.
- Given the outcome of the last rate case and settlement, the Company has already made some pipeline replacement investments (21 miles) that presumably are included in the current test year. In order for the Company's presumption to be correct, the magnitude of these future incremental investments would have to be greater than what is included in the test year.
- Even if correct, the position presumes that an accelerated rate of replacement (over what is in the test year) needs to occur. The Company has not provided any analysis that accelerated replacement is needed for economic, safety, or reliability purposes.

Q. LET'S TURN TO THE FIRST POINT YOU RAISED. ARE THESE PIPELINE REPLACEMENT INVESTMENTS LARGE ON AN ANNUAL AVERAGE BASIS?

A. No. The Company's notes that, in total it will replace 80 miles of pipe over a 14 year period. It has already replaced 21 miles of pipe since the last rate case (four years), which leaves only 59 miles of pipe to be replaced over the next ten years. If one were to assume an average cost of $50 per foot, or $264,000 per mile[78], replacing this 59 miles of pipe over ten years would cost the Company approximately $54,000 the first year, and increase by a similar amount in each of the next nine years. Nevertheless, this is not an amount that would create a financial crisis for the Company.[79]

Q. WHAT ABOUT YOUR SECOND POINT REGARDING THE COMPANY'S TEST YEAR REPLACEMENT ACTIVITIES?

A. The Company notes that it has already replaced 21 miles of pipe since the last rate case (four years), which leaves only 59 miles of pipe to be replaced over the next ten years. Thus, the Company has replaced pipe at an annual average rate of about 5.2 miles per year. The future replacement level is about 5.9 miles per year. Thus the two levels are comparable. If the Company's current test year includes an amount greater than or equal to 5.2 miles per year, it is likely to generate sufficient revenue, other things equal, to cover those investment costs.

[78] The assumption of $55 per foot is for 12-inch steel pipe.
[79] This uses the Company's proposed ROE of 11 percent.

Q. WHAT ABOUT YOUR THIRD OBSERVATION. HAS THE COMPANY JUSTIFIED THE NEED FOR ACCELERATED INFRASTRUCTURE REPLACEMENT?

A. No. Exhibit DED-22 provides a number of comparisons of the Company's unprotected bare steel and cast iron pipeline inventory relative to other southeastern LDCs. Page 1 shows that the Company's share of total unprotected pipe is about 4.2 percent of all distribution plant, lower than the peer average of 5.2 percent. A comparison of the Company's replacement activity to other southeastern gas utilities, indexed to 1991, has been provided on page 2 of the exhibit and shows that the Company's replacement efforts are lacking in comparison to its peers. Page 3 of the exhibit provides a comparison of the Company's annual corrosion-related leaks relative to other southeastern utilities. Again, the Company's numbers are low relative to the peer group. Thus, the need for any accelerated pipeline replacement activity is questionable: the Company currently has a relatively small share of pipe needing replacement and has a relatively low number of reported leaks.

Q. WHAT ARE YOUR RECOMMENDATIONS ON THE USE OF THE COMPANY'S REVENUE DECOUPLING TRACKER TO SUPPORT INFRASTRUCTURE REPLACEMENT?

A. I recommend that the TRA reject the Company's assertion that somehow, the adoption of revenue decoupling will be supportive, or should be used as supportive of infrastructure replacement activities. Revenue decoupling, to the extent it is adopted, should be used exclusively to support energy efficiency activities, not infrastructure replacement or other revenue stabilization, or revenue enhancement measures. Further, the Company has not provided any effective evidence that: (1) shows currently-proposed rates are deficient in supporting its future investment activities; and (2) that there is a need for accelerating replacement activities beyond what is already included in the Company's proposed rates.

XV. CONCLUSIONS AND RECOMMENDATIONS

WHAT ARE YOUR REVENUE DECOUPLING RECOMMENDATIONS?

A. I recommend that the TRA reject the Company's proposed AUA, or revenue decoupling tracker mechanism for the following reasons:

- Revenue decoupling is not needed in order for regulatory policy to be consistent with federal and Tennessee energy legislation. This point has already been clearly articulated by the TRA in the Piedmont case[80], and no evidence has been provided in this proceeding that would justify a deviation from that precedent.
- The Company's revenue decoupling tracker is entirely inconsistent with traditional regulation and, like most tracker mechanisms, would lead to a number of disincentives for cost efficiency and risk management. The disincentive for cost efficiency created by revenue decoupling has been recognized twice by the TRA. I recommend the TRA continue to uphold this precedent in the instant proceeding.

[80] See In Re: Petition of Piedmont Natural Gas, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs, TRA Docket No. 09-00104. Petition filed July 16, 2009.

- The Company's revenue decoupling tracker would transfer a considerable amount of sales risk away from shareholders and towards ratepayers with virtually no reciprocal, nor proportional, benefits.
- The Company's proposed revenue decoupling tracker includes no ratepayer protection mechanisms.
- The Company has not shown that its proposed energy efficiency programs would create any form of financial harm.
- The scale and scope of the Company's proposed energy efficiency program does not rise to the level where a revenue decoupling mechanism is needed. The annual lost base revenues resulting from the Company's proposed energy efficiency measures, conservatively, are estimated to be only $202,355 million, over the first five years of the program.
- Any potential negative financial impacts resulting from these limited energy efficiency programs, to the extent they occur, could easily be accommodated within a lost base revenues mechanism.

Q. DO YOU HAVE ANY RECOMMENDATIONS ABOUT THE COMPANY'S ATTEMPT TO TIE REVENUE DECOUPLING TO INFRASTRUCTURE REPLACEMENT?

A. I recommend that the TRA reject the Company's assertion that the adoption of revenue decoupling will be supportive, or should be used as supportive, of infrastructure replacement activities. Revenue decoupling, to the extent it is adopted, should be used exclusively to support energy efficiency activities, not infrastructure replacement or other revenue stabilization, or revenue enhancement measures. Further, the Company has not provided any effective evidence that: (1) shows currently-proposed rates are deficient in supporting its future investments; and (2) that there is a need for accelerating replacement activities beyond what is already included in the Company's proposed rates.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED ENERGY EFFICIENCY PLAN?

A. Yes. The cost effectiveness plan supporting the Company's energy efficiency program includes a number of mechanical errors, input errors, and faulty assumptions that yield unreliable results. I recommend that the TRA reject the Company's cost effectiveness analysis, and utilize the alternative analysis I have provided that shows a very limited amount of cost-effective energy efficiency savings that will be offered in return for a very large change in the way the Company is regulated. The Company's energy efficiency plan also lacks any independent monitoring and verification and should be rejected until such a plan can be presented for the TRA's consideration. Lastly, the TRA should also reject the Company's proposed Education and Outreach program since it is lacking in detail, a formalized plan, goals and independent oversight. The Company's plan more closely resembles an advertising and goodwill campaign rather than an education and conservation plan.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes. If the TRA would like to actively promote energy efficiency, I recommend that a performance-based mechanism that rewards CGC for greater-than-average success at achieving its energy efficiency potentials be adopted. No performance-based approach should be adopted until the Company submits, for approval, a monitoring and verification plan for its energy efficiency program.

Q. DO YOU HAVE ANY RECOMMENDATIONS IN THE EVENT THAT THE TRA DECIDES TO ADOPT REVENUE DECOUPLING?

A. Yes. If the TRA accepts the Company's decoupling proposal, I recommend the following modifications to the mechanism:

- Include an ROE adjustment as recommended by Dr. Christopher Klein.
- Reject the Company's proposal to allow revenue recovery amounts to increase with customer growth.
- Include a consumer protection mechanism that would restrict decoupling revenue recovery amounts to either:
    - A level no greater than the annual capacity and throughput cost savings from the purchased gas acquisition ("PGA") clause. ("New Jersey Approach")
    - An amount that does not exceed 24 percent, and decreases relative to shortfalls in reaching target energy efficiency savings. ("Washington Approach").
- If the TRA opts to not use a threshold percent, then include an additional consumer protection measure that restricts revenue decoupling accruals to no more than 2.0 percent of total revenues.

- Require a review of the decoupling mechanism in no more than three years. The Company's decoupling mechanism should be evaluated against strong energy efficiency performance goals. These goals should be based on the Company's performance in meeting its savings targets estimated for its proposed energy efficiency programs. This review should include a regulatory presumption that the decoupling mechanism will be repealed in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.
- Define criteria for the decoupling review that would include: (1) an energy efficiency review; (2) a revenue deferrals and collections review; (3) a customer usage analysis; and (4) other mutually acceptable review criteria that are defined by the TRA, the Company, and other stakeholders such as the Consumer Advocate.
- The Company should make annual compliance filings with the Authority that identifies and compares estimated and actual costs incurred for each program, the estimated and actual number of participants for each program, and the estimated and actual therm savings for each program. A complete listing, and cost itemization for the Company's market transformation (education) activities should also be provided as well as annual collections, and running net balances for collections made under the decoupling tracker.
- The Company should be held to performance metrics on program costs

and savings.

Q DOES THIS COMPLETE YOUR TESTIMONY FILED ON MARCH 10, 2010?

A. Yes.

Attachment 1

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola Junior College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

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3. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

4. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

5. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

6. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.

7. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

8. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

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4. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry” (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

5. “New Paradigms for Power Engineering Education.” (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

6. “Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf” (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

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PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. “A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements” (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

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32. “Clean Air, Kyoto, and the Boy Who Cried Wolf.” (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

33. “Energy Conservation Programs and Electric Restructuring: Is There a Conflict?” (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

34. “The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry.” (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

35. “Issues and Opportunities for Small Scale Electricity Production in the Oil Patch.” (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

36. “Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry.” (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

37. “Coming to a Neighborhood Near You: The Merchant Electric Power Plant.” (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.

38. “Slow as Molasses: The Political Economy of Electric Restructuring in the South.” (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

39. “Stranded Investment and Non-Utility Generation.” (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

40. “Reliability or Profit? Why Entergy Quit the Southwest Power Pool.” (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.

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6. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

7. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

8. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

9. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

10. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

11. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

12. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

13. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

14. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

15. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

16. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

17. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

18. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

19. *Energy Conservation and Electric Restructuring In Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

20. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

21. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator*. “Economic Contributions and Benefits Support by the Port of Venice.” Port of Venice Coalition. Total Project: $20,000. Status: Completed.

2. *Principal Investigator.* “Energy Policy Development in Louisiana.” Louisiana Department of Natural Resources. Total Project: $49,500. Status: Completed.

3. *Principal Investigator.* “Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation.” With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: In Progress.

4. *Principal Investigator*. “OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity.” (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Awarded, In Progress.

5. *Principal Investigator*. “State and Local Level Fiscal Effects of the Offshore Petroleum Industry.” (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

6. *Principal Investigator*. “Understanding Current and Projected Gulf OCS Labor and Ports Needs.” (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

7. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

8. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

9. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

10. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

11. *Principal Investigator*. "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

12. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

13. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

14. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

15. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

16. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

17. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding:

$557,744. Status: Awarded, In Progress.

18. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

19. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

20. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

21. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

22. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

23. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7, 2009.

2. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

3. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

5. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

6. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

7. “An Examination of LNG Development on the Gulf of Mexico.” (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

8. “OCS-Related Infrastructure on the GOM: Update and Summary of Impacts.” (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

9. “The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America’s Estuaries. New Orleans, Louisiana, December 11.

10. “The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey.” (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

11. “The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast.” (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

12. “Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned.” (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

13. “An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana.” (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

14. “Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases.” (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

15. “GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand.” (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

16. “Are There Any In-State Uses for Alaska Natural Gas?” (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: “Energy Markets in Turmoil: Making Sense of It All.” Vancouver, British Columbia, Canada. October 7.

17. “The Economic Impact of State Oil and Gas Leases on Louisiana.” (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

18. “Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana.” (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

19. “New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico.” (2002). With Vicki Zatarain. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

20. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

21. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

22. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

23. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

24. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

25. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

26. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

27. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

28. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

29. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

30. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

31. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

32. “A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry.” (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

33. “New Paradigms for Power Engineering Education.” (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

34. “Cogeneration and Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

35. “The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978.” (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. “Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS.” (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. “Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry” (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. “Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries” (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. “Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry.” (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. “Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators.” (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. “Empirical Determinants of Nuclear Power Plant Disallowances.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. “A Cross-Sectional Model of IntraLATA MTS Demand.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. “Energy Regulation: Overview of Power and Gas Regulation.” Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. “Trends and Issues in Renewable Energy.” Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. “CES Research Projects and Status.” Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. “Hurricane Impacts on Energy Production and Infrastructure.” Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. “Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. “Electric Restructuring and Conservation.” (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. “Electric Restructuring and the Environment.” (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. “Electric Restructuring and Nuclear Power.” (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. “The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

2. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

3. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. November 10, 2009.

4. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

5. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

6. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

7. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

8. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

9. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

10. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

11. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

12. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

13. “The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers.” (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

14. Panelist, “Expanding Exploration of the U.S. OCS” (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

15. “Gulf Coast Energy Outlook.” (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

16. “Background, Issues, and Trends in Underground Hydrocarbon Storage.” (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

17. “Greenhouse Gas Regulations and Policy: Implications for Louisiana.” (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

18. “Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives.” (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

19. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

20. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency.” (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

21. “Regulatory and Policy Issues in Nuclear Power Plant Development.” (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

22. “Oil and Gas in the Gulf of Mexico: A North American Perspective.” (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

23. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates (“NASUCA”) Gas Committee Monthly Meeting. February 13, 2006.

24. “Recent Trends in Natural Gas Markets.” (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

25. “Energy Markets: Recent Trends, Issues & Outlook.” (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

26. “Energy Outlook” (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

27. “Global and U.S. Energy Outlook.” (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

28. “Interdependence of Critical Energy Infrastructure Systems.” (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

29. “Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006) The Economic and Market Impacts of Coastal Restoration: America’s Wetland Economic Forum II. Washington, DC September 28, 2006.

30. “Relationships between Power and Other Critical Energy Infrastructure.” (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

31. “Outlook, Issues, and Trends in Energy Supplies and Prices.” (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

32. “Energy Sector Outlook.” (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

33. “Oil and Gas Industry Post 2005 Storm Events.” (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

34. “Concentration of Energy Infrastructure in Hurricane Regions.” (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

35. “LNG—A Premier.” (2006). Presentation Given to the U.S. Department of Energy’s “LNG Forums.” Los Angeles, California. June 1, 2006.

36. “Regional Energy Infrastructure, Production and Outlook.” (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

37. “The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook.” Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

38. “Update on Regional Energy Infrastructure and Production.” (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

39. “Hurricane Impacts on Energy Production and Infrastructure.” (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

40. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

41. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

42. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

43. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

44. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

45. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

46. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

47. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

48. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

49. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

50. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

51. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

52. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

53. “CES 2005 Legislative Support and Outlook for Energy Markets and Policy.” Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

54. “Electric Restructuring: Past, Present, and Future.” Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

55. “The Outlook for Energy.” Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

56. “The Outlook for Energy.” Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

57. “Background and Overview of LNG Development.” Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

58. “Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry.” Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

59. “The Economic Opportunities for a Limited Industrial Retail Choice Plan.” Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

60. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

61. “Energy Issues for Industrial Customers of Gas and Power.” Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

62. “Energy Issues for Industrial Customers of Gas and Power.” American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

63. “Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry.” Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

64. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

65. “LNG In Louisiana.” Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

66. “Louisiana Energy Issues.” Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

67. “The Gulf South: Economic Opportunities Related to LNG.” Presentation before the Energy Council’s 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

68. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

69. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

70. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

71. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

72. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

73. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

74. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

75. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

76. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

77. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

78. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

79. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

80. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

81. “What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

82. “An Introduction to Distributed Energy Resources.” Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

83. “Merchant Energy Development Issues in Louisiana.” Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

84. “Power Plant Siting Issues in Louisiana.” Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

85. “Merchant Power and Deregulation: Issues and Impacts.” Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

86. “Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana.” Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

87. “Economic Impacts of Merchant Power Plant Development in Mississippi.” Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

88. “Economic Opportunities for Merchant Power Development in the South.” Presentation before the Southern Governor’s Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

89. “The Changing Nature of the Electric Power Business in Louisiana.” Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

90. “Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

91. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

92. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

93. “The Economic Impacts of Merchant Power Plant Development In Mississippi.” Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

94. “Energy Conservation and Electric Restructuring.” With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

95. “Pricing and Regulatory Issues Associated with Distributed Energy.” Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: “Is the Window Closing for Distributed Energy?” Houston, Texas, October 13, 2000.

96. “Electric Reliability and Merchant Power Development Issues.” Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

97. “A Introduction to Distributed Energy Resources.” Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

98. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

99. “Electricity 101: Definitions, Precedents, and Issues.” Energy Council’s 2000 Federal Energy and Environmental Matters Conference. Loews L’Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

100. “LSU/CES Distributed Energy Resources Initiatives.” Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

101. “Distributed Energy Resources Initiatives.” Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

102. “Merchant Power Opportunities in Louisiana.” Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

103. Roundtable Discussant. “Environmental Regulation in a Restructured Market” The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

104. “The Political Economy of Electric Restructuring In the South” Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

105. “The Dynamics of Electric Restructuring in Louisiana.” Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

106. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

107. “What’s Happened to Electricity Restructuring in Louisiana?” Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

108. “A Short Course on Electric Restructuring.” Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

109. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

110. “How Will Utility Deregulation Affect Tourism.” Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

111. “Reflections and Predictions on Electric Utility Restructuring in Louisiana.” With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

112. “Electric Utility Restructuring in Louisiana.” Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

113. “Electric Utility Restructuring.” Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

114. “Electric Utility Restructuring: Issues and Trends for Louisiana.” Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

115. “The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues.” Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

116. “Electric Restructuring: Louisiana Issues and Outlook for 1997.” Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

117. “Restructuring the Electric Utility Industry.” Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

118. “Deregulating the Electric Utility Industry.” Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

119. “Electric Utility Restructuring in Louisiana.” Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

120. “Electric Utility Restructuring in Louisiana.” Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

121. “Electric Utility Restructuring” Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

122. “Electric Utility Restructuring -- Background and Overview.” Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

123. “Electric Utility Restructuring.” Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

124. Roundtable Moderator, “Stakeholder Perspectives on Electric Utility Stranded Costs.” Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

125. Panelist, “Deregulation and Competition.” American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Before the Tennessee Regulatory Authority. Docket 09-00104. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review.

2. Expert Testimony. Before the Nebraska Public Service Commission. Docket Number NG-0060. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

3. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

4. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

5. Expert Testimony. Docket EO09030249. Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

6. Expert Testimony. Docket EO0920097. Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the

Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

7. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

8. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

9. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

10. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

11. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

12. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

13. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

14. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

15. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

16. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

17. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

18. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

19. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

20. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

21. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

22. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

23. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

24. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service

Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

25. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

26. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

27. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

28. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

29. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

30. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

31. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

32. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

33. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida

Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

34. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

35. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

36. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

37. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

38. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

39. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

40. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

41. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

42. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

43. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities

Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

44. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

45. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

46. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

47. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

48. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

49. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

50. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

51. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

52. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

53. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with

Tax Incentives on Merchant Power Generation and Transmission.

54. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

55. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

56. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

57. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

58. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

59. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

60. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

61. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

62. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-Current, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Econometric Society, Southern Economic Association, Western Economic Association, and the International Association of Energy Economists.

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory
Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.
Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).
Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric

Engineering).

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

<u>THESIS/DISSERTATIONS COMMITTEES</u>

5 Thesis Committee Memberships (Environmental Studies, Geography)
3 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics).
1 Doctoral Examination Committee Membership (Information Systems & Decision Sciences)
1 Senior Honors Thesis (Journalism, Loyola University)

<u>LSU SERVICE AND COMMITTEE MEMBERSHIPS</u>

Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-Current)

LSU Faculty Senate (2003-2006)

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Chattanooga Gas Company
Proposed DSM Program Components

	Participants per Year	Incentive	Unit	Annual Energy Savings: Savings per Participant: Therms	Dollars ($)	Total Savings: Therms	Dollars ($)	Total Cost: Year 1	Year 2	Year 3	Year 4
								($)			
Residential Measures											
Free Programmable Thermostats	1,500	$ 20	Furnace/Boiler	26	$ 20	39,000	$ 29,541	$ 30,000	$ 30,000	$ 30,000	$ 30,000
Low Income Weatherization	120	$ 1,650	Home	130	$ 101	15,600	$ 12,140	$ 198,000	$ 198,000	$ 198,000	$ 198,000
High Efficiency Furnace/Boiler Incentive	500	$ 500	Furnace/Boiler	67	$ 82	33,500	$ 41,121	$ 250,000	$ 250,000	$ 250,000	$ 250,000
Tankless Water Heater Incentive	300	$ 500	Appliance	57	$ 70	17,100	$ 20,944	$ 150,000	$ 150,000	$ 150,000	$ 150,000
High Efficiency Storage Water Heater Incentive	100	$ 150	Appliance	24	$ 29	2,400	$ 2,860	$ 15,000	$ 15,000	$ 15,000	$ 15,000
sub-Total Residential before Asset Management Funding						107,600	$106,606	$ 643,000	$ 643,000	$ 643,000	$ 643,000
less Asset Management Funding for Low Income Weatherization								$(198,000)	$(198,000)	$(198,000)	$(198,000)
Total Residential Programs						107,600	$106,606	$ 445,000	$ 445,000	$ 445,000	$ 445,000
Commercial Measures											
Food Service Equipment	200	$ 200	Appliance	48	$ 42	9,600	$ 8,352	$ 40,000	$ 40,000	$ 40,000	$ 40,000
High Efficiency Furnace/Boiler Incentive	135	$ 500	Furnace/Boiler	67	$ 58	9,045	$ 7,869	$ 67,500	$ 67,500	$ 67,500	$ 67,500
Tankless Water Heater Incentive	60	$ 500	Appliance	435	$ 378	26,100	$ 22,706	$ 30,000	$ 30,000	$ 30,000	$ 30,000
High Efficiency Storage Water Heater Incentive	15	$ 300	Appliance	161	$ 140	2,415	$ 2,101	$ 4,500	$ 4,500	$ 4,500	$ 4,500
Booster Water Heater Incentive	25	$ 200	Appliance	495	$ 431	12,375	$ 10,766	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Total Commercial Measures						59,535	$ 51,793	$ 147,000	$ 147,000	$ 147,000	$ 147,000
Administration, Customer Outreach and Education								$ 300,000	$ 250,000	$ 225,000	$ 200,000
less CGC Contribution								$(100,000)	$ (50,000)	$ (25,000)	$ 0
Total energySMART						**167,135**	**$158,399**	**$ 792,000**	**$ 792,000**	**$ 792,000**	**$ 792,000**

Source: Response to CAPD Question 151, Attachment 151-2.

Chattanooga Gas Company
Comparison of CGC and Other LDC Programs

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-2
Page 1 of 1

	Program Spending (million $)	Percent of Retail Revenues (%)	Gas Savings (Mcf/year)	Percent of Gas Sales Saved (%)	Mcf/year Saved per Million $* (Mcf/year)	Benefit-Cost Ratio
Aquila (Minnesota)	2.1	**1.4%**	146,000	0.5%	69,000	--
Centerpoint	5.6	**0.5%**	720,000	0.5%	129,000	2.6
Keyspan	12.0	**1.0%**	490,000	0.4%	41,000	3.0
Northwest Natural Gas	4.7	**0.7%**	85,000	0.1%	18,000	--
NSTAR	3.9	**0.8%**	71,500	0.2%	18,000	2.3
PG&E	21.7	**0.7%**	2,040,000	0.7%	94,000	2.1
PSE	3.8	**0.4%**	311,000	0.5%	82,000	1.9
Southern California Gas	21.0	**0.6%**	1,100,000	0.3%	53,000	2.7
Vermont Gas	1.1	**1.6%**	57,000	1.0%	57,000	5.6
Xcel Energy (Minnesota)	4.0	**0.7%**	663,000	0.9%	166,000	1.6
Average	**8.0**	**0.8%**	**568,350**	**0.5%**	**72,700**	**2.7**
Median	4.4	**0.7%**	400,500	0.5%	63,000	2.4
Chattanooga Gas Company	**0.8**	**0.5%**	**16,714**	**0.2%**	**21,103**	**2.2**

Note: * First year energy savings per million dollars of program expenditures.
Source: Tegen, S. and Geller, H. Natural Gas Demand-Side Management Programs: A National Survey, Southwest Energy Efficiency Project, January 2006; and Response to CAPD Question 151, Attachment 151-2.

Chattanooga Gas Company
energySMART Customer Outreach & Education Plan

	Unit Size	Total Insertion	Cost ($)	Percent of Total Cost (%)
Radio Communication	:60		$50,000	16.7%
Print Communication				
Chattanooga Times Free Press	Special Insert	3	$49,080	16.4%
Cleveland Daily Banner		6	$11,000	3.7%
Chattanooga Magazine		3	$11,500	3.8%
Online Communication				
chattanoogagas.com			N/A	
timesfreepress.com	Banner Ads		Value Add	
Google AdWords	NA		$2,500	0.8%
Out of Home Communication				
Rotary Billboard		1	$15,000	5.0%
Trade Outreach and Communication				
HVAC / Plumber Kickoff Breakfast		1	$750	0.3%
Plumbing News Ad	Jr. Page FC	7	$5,075	1.7%
HVAC Insider Ad	Jr. Page 4C	7	$6,832	2.3%
Dealer Energy Efficiency Workshops (Res & Comm)		2	$3,200	1.1%
Dealer Literature (program overview, forms)			$500	0.2%
HBAST Luncheon Presentations		2	$500	0.2%
Direct Mail				
eDM Program Announce to opt-in customers		12,000	$240	0.1%
Residential - Older/Inefficient Homes		40,000	$26,000	8.7%
Weatherization Program		3,000	$1,950	0.7%
Commercial - Program Announcement		8,000	$5,200	1.7%
energySMART Program Bill Insert	4C DS Buckslip	5	$9,000	3.0%
Community Outreach / Events / Sponsorships				
Commercial Customer EE Workshops		2	$3,500	1.2%
Homeowner EE Workshop Series		6	$37,500	12.5%
Exhibit display			$5,000	1.7%
Civic & community presentation/exhibit opportunities		TBD	$10,500	3.5%
Collateral / Literature				
Literature - Residential Programs	4C Handouts		$3,125	1.0%
Literature - Commercial Programs	4C Handouts		$1,250	0.4%
Consumer Booklet - Energy Efficiency	4C		$3,500	1.2%
Energy Savvy Magazine	8 pg 4C	3 x 50k	$30,000	10.0%
Wallet Cards	4C	5,000	$1,000	0.3%
Doorhangers	4C	2,500	$1,000	0.3%
Lapel Buttons	2C	250	$500	0.2%
Other				
Employee Program Kickoff			$500	0.2%
Program Manager travel to support eS events			$4,000	1.3%
TOTAL			$299,702	100.0%

Note: The response to this data request also included a Gantt chart with the Company's proposed timeline which was excluded from this exhibit due to size limitations. Source: Response to CAPD Question 171, Attachment 171-1.

Chattanooga Gas Company
Results of Cost-Effectiveness Tests

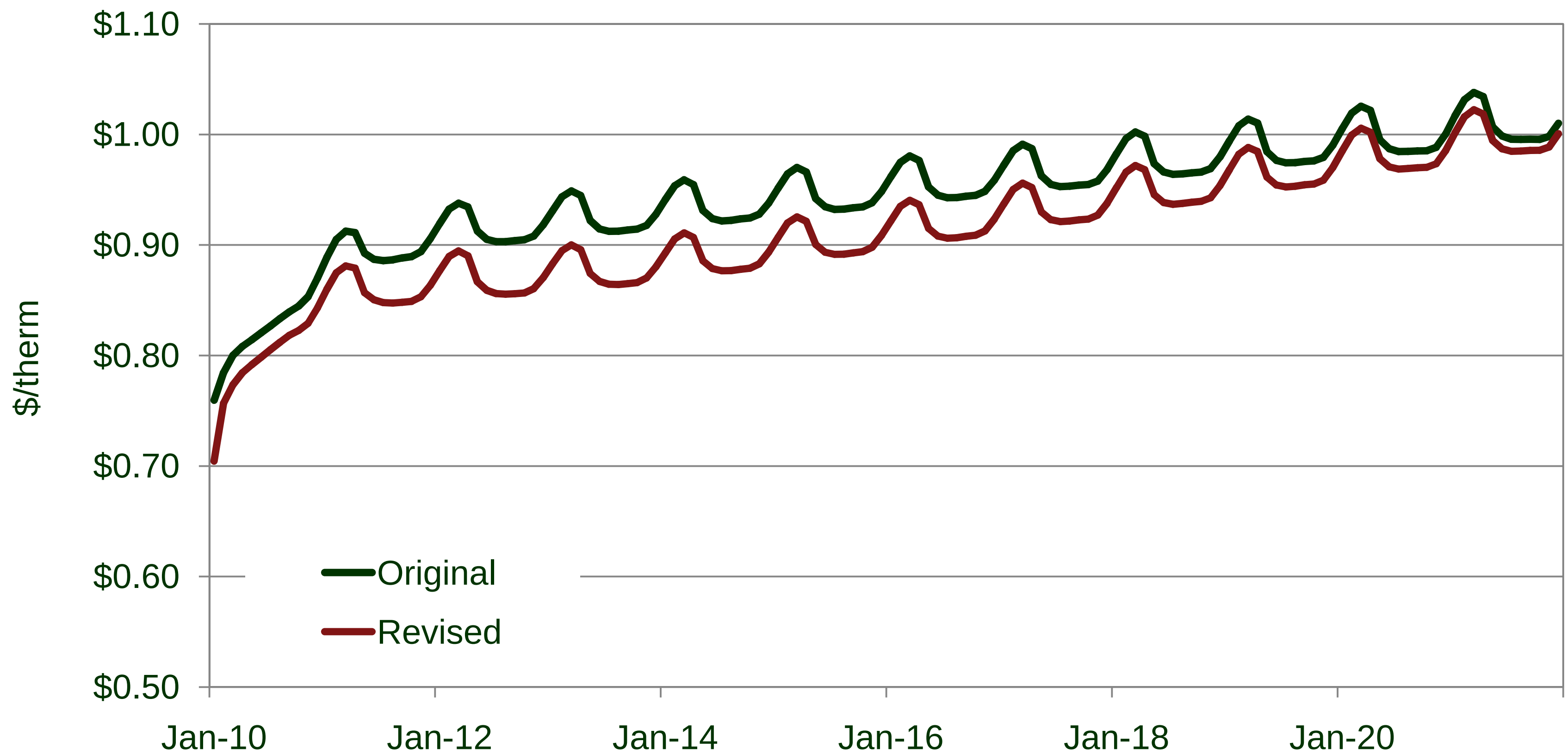
Witness: Dismukes
Docket No. 09-00183
Exhibit DED-4

	Residential Measures					Commercial Measures					
	Free Programmable Thermostats	**Low Income Weatherization**	**High Efficiency Furnace/ Boiler Incentive**	**Tankless Water Heater Incentive**	**High Efficiency Storage Water Heater Incentive**	**Food Service Equipment**	**High Efficiency Furnace/ Boiler Incentive**	**Tankless Water Heater Incentive**	**High Efficiency Storage Water Heater Incentive**	**Booster Water Heater Incentive**	**Total energySmart**
Participants Test											
Total Benefits	$ 1,678,264	$ 1,658,551	$ 2,988,099	$ 1,826,125	$ 182,610	$ 968,968	$ 843,217	$ 1,100,782	$ 97,558	$ 441,620	$ 11,785,793
Total Costs	$ 674,092	$ 539,274	$ 1,797,580	$ 943,729	$ 78,644	$ 359,516	$ 485,347	$ 188,746	$ 33,705	$ 337,046	$ 5,437,679
Net Benefit	$ 1,004,172	$ 1,119,277	$ 1,190,519	$ 882,395	$ 103,966	$ 609,452	$ 357,870	$ 912,036	$ 63,854	$ 104,574	$ 6,348,114
Benefit/Cost Ratio	**2.49**	**3.08**	**1.66**	**1.94**	**2.32**	**2.70**	**1.74**	**5.83**	**2.89**	**1.31**	**2.17**
Rate Impact Measure Test											
Total Benefits	$ 3,063,486	$ 940,515	$ 2,378,094	$ 1,190,336	$ 118,907	$ 815,453	$ 690,273	$ 998,013	$ 79,886	$ 433,007	$ 10,707,969
Total Costs	$ 1,692,427	$ 1,659,684	$ 2,992,819	$ 1,828,957	$ 183,554	$ 970,857	$ 844,491	$ 1,101,348	$ 97,700	$ 441,856	$ 12,013,693
Net Benefit	$ 1,371,059	$ (719,169)	$ (614,726)	$ (638,621)	$ (64,647)	$ (155,403)	$ (154,218)	$ (103,335)	$ (17,814)	$ (8,850)	$ (1,305,724)
Benefit/Cost Ratio	**1.81**	**0.57**	**0.79**	**0.65**	**0.65**	**0.84**	**0.82**	**0.91**	**0.82**	**0.98**	**0.89**
Total Resource Cost Test											
Total Benefits	$ 3,063,486	$ 940,515	$ 2,378,094	$ 1,190,336	$ 118,907	$ 815,453	$ 690,273	$ 998,013	$ 79,886	$ 433,007	$ 10,707,969
Total Costs	$ 688,255	$ 540,407	$ 1,802,301	$ 946,562	$ 79,588	$ 361,404	$ 486,621	$ 189,312	$ 33,846	$ 337,282	$ 5,665,579
Net Benefit	$ 2,375,231	$ 400,108	$ 575,793	$ 243,774	$ 39,318	$ 454,049	$ 203,652	$ 808,701	$ 46,039	$ 95,724	$ 5,042,390
Benefit/Cost Ratio	**4.45**	**1.74**	**1.32**	**1.26**	**1.49**	**2.26**	**1.42**	**5.27**	**2.36**	**1.28**	**1.89**
Program Administrator Test											
Total Benefits	$ 3,063,486	$ 940,515	$ 2,378,094	$ 1,190,336	$ 118,907	$ 815,453	$ 690,273	$ 998,013	$ 79,886	$ 433,007	$ 10,707,969
Total Costs	$ 148,981	$ 890,935	$ 1,128,208	$ 676,925	$ 68,353	$ 181,646	$ 304,616	$ 135,386	$ 20,366	$ 22,709	$ 3,778,126
Net Benefit	$ 2,914,505	$ 49,580	$ 1,249,886	$ 513,411	$ 50,553	$ 633,807	$ 385,657	$ 862,627	$ 59,519	$ 410,298	$ 6,929,843
Benefit/Cost Ratio	**20.56**	**1.06**	**2.11**	**1.76**	**1.74**	**4.49**	**2.27**	**7.37**	**3.92**	**19.07**	**2.83**

Source: Response to CAPD Question 151, Attachment 151-2.

Chattanooga Gas Company
Original and Revised Gas Price Projections

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-5
Page 1 of 1



Source: Response to CAPD Question 151, Attachments 151-1 and 151-2.

Chattanooga Gas Company
Original and Revised Cost-Effectiveness Results

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-6

	Residential Measures					Commercial Measures					
	Free Programmable Thermostats	Low Income Weatherization	High Efficiency Furnace/ Boiler Incentive	Tankless Water Heater Incentive	High Efficiency Storage Water Heater Incentive	Food Service Equipment	High Efficiency Furnace/ Boiler Incentive	Tankless Water Heater Incentive	High Efficiency Storage Water Heater Incentive	Booster Water Heater Incentive	Total energySmart
Original Benefit-Cost Ratio											
Participants Test	$ 2.54	$ 3.10	$ 1.28	$ 1.53	$ 2.37	$ 1.80	$ 1.24	$ 5.56	$ 2.72	$ 1.35	$ 2.16
Rate Impact Measure Test	$ 1.89	$ 0.57	$ 0.84	$ 0.55	$ 0.66	$ 0.95	$ 0.80	$ 0.91	$ 0.80	$ 0.99	$ 0.81
Total Resource Cost Test	$ 4.74	$ 1.76	$ 1.08	$ 0.84	$ 1.54	$ 1.70	$ 0.99	$ 5.02	$ 2.18	$ 1.34	$ 1.72
Program Administrator Test	$ 21.91	$ 1.07	$ 1.72	$ 1.17	$ 1.80	$ 3.39	$ 1.58	$ 7.02	$ 3.62	$ 19.85	$ 1.92
Revised Benefit-Cost Ratio											
Participants Test	$ 2.49	$ 3.08	$ 1.66	$ 1.94	$ 2.32	$ 2.70	$ 1.74	$ 5.83	$ 2.89	$ 1.31	$ 2.17
Rate Impact Measure Test	$ 1.81	$ 0.57	$ 0.79	$ 0.65	$ 0.65	$ 0.84	$ 0.82	$ 0.91	$ 0.82	$ 0.98	$ 0.89
Total Resource Cost Test	$ 4.45	$ 1.74	$ 1.32	$ 1.26	$ 1.49	$ 2.26	$ 1.42	$ 5.27	$ 2.36	$ 1.28	$ 1.89
Program Administrator Test	$ 20.56	$ 1.06	$ 2.11	$ 1.76	$ 1.74	$ 4.49	$ 2.27	$ 7.37	$ 3.92	$ 19.07	$ 2.83

Source: Response to CAPD Question 151, Attachments 151-1 and 151-2.

Chattanooga Gas Company
Historic Escalation of Interstate Pipeline Rates

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-7

Pipeline / Rate Schedule	Current Rate	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Tennessee Gas Pipeline											
FT-A	$ 6.45000	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500	$ 6.4500
FS	$ 2.02000	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200	$ 2.0200
FS	$ 0.02480	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248
FS	$ 1.15000	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500	$ 1.1500
FS	$ 0.01850	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185
East Tennessee											
FT-A	$ 6.68000	$ 6.6800	$ 6.6800	$ 6.6800	$ 6.6800	$ 7.2100	$ 7.2100	n.a.	n.a.	n.a.	n.a.
Southern Natural Gas Company											
FT-NN	$ 15.53000	$ 15.5300	$ 15.5300	$ 15.5300	$ 15.5300	$ 15.5300	$ 11.8900	$ 11.8900	$ 11.8900	$ 11.8900	$ 11.8900
FT	$ 15.53000	$ 15.5300	$ 15.5300	$ 15.5300	$ 15.5300	$ 15.5300	$ 11.8900	$ 11.8900	$ 11.8900	$ 11.8900	$ 11.8900
CSS	$ 1.69200	$ 1.6920	$ 1.6920	$ 1.6920	$ 1.6920	$ 1.5720	$ 1.5720	$ 1.5720	$ 1.5720	$ 1.5720	$ 1.5440
CSS	$ 0.03305	$ 0.0331	$ 0.0331	$ 0.0331	$ 0.0331	$ 0.0303	$ 0.0303	$ 0.0303	$ 0.0303	$ 0.0303	$ 0.0283

Note: “n.a.” is not available.
Source: Response to CAPD Question 153, Attachment CAP-D 1-153.1; Response to CAPD Question 154, Attachment CAP-D 1-154.1; Federal Energy Regulatory Commission; Tennessee Gas Pipeline: http://www.tennesseeadvantage.com/default.asp; and Southern Natural Gas Company: https://premier.sonetpremier.com/SNGHomePage/index.aspx.

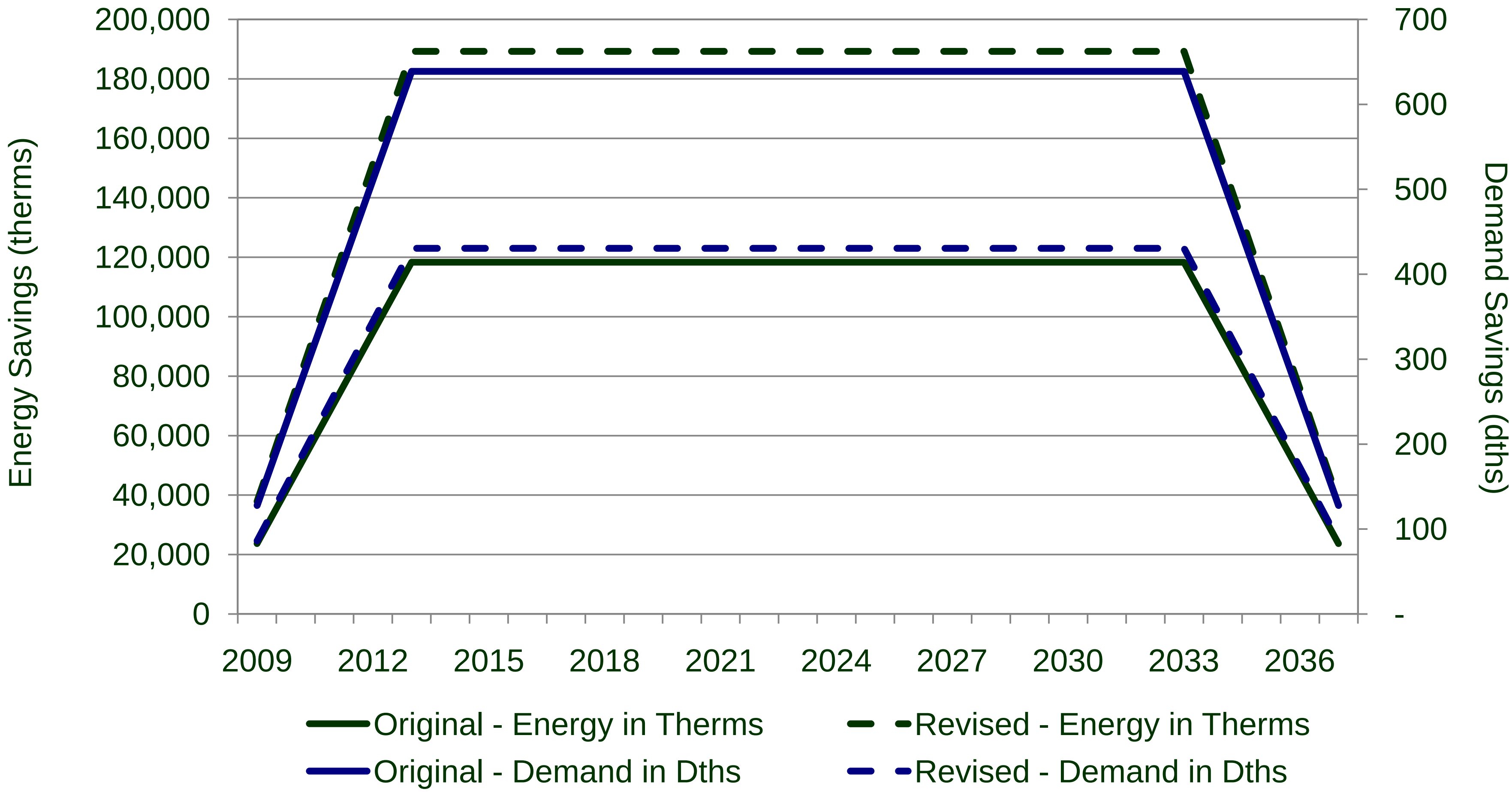
Chattanooga Gas Company
Revised Assumptions to CE Model

	Residential Programs									
	Programable Thermostat		Low Income Weatherization		High Efficiency Furnace/Boiler Incentive		Tankless Water Heater Incentive		High Efficiency Storage Water Heater Incentive	
	CGC	AG	CGC	AG	CGC	AG	CGC	AG	CGC	AG
General Program Evaluation Assumptions:										
Equipment Life (Years)	17	10	25	20	25	18	20	20	12	10
Program Length (Years)	5	5	5	5	5	5	5	5	5	5
Annual Number of Incremental Partcipants	1,500	954 - 1,500	120	17 - 34	500	131 - 262	300	55 - 109	100	20 - 40
Annual Program Savings Per Partcipant	(26)	(15)	(130)	(200)	(107)	(80)	(88)	(85)	(36)	(35)
Net to Gross Ratio	1.00	0.49	1.00	1.00	0.71	0.60	1.00	0.58	1.00	0.58
Cost to Participant (Incremental Cost of Product)	$ 100	$ 100	$ 1,000	$ 1,000	$ 800	$ 800	$ 700	$ 1,700	$ 175	$ 175

	Commercial Programs									
	Food Service Equipment		High Efficiency Furnace/Boiler Incentive		Tankless Water Heater Incentive		High Efficiency Storage Water Heater Incentive		Booster Water Heater Incentive	
	CGC	AG	CGC	AG	CGC	AG	CGC	AG	CGC	AG
General Program Evaluation Assumptions:										
Equipment Life (Years)	15	15	15	15	15	15	12	10	15	15
Program Length (Years)	5	5	5	5	5	5	5	5	5	5
Annual Number of Incremental Partcipants	200	200	135	135	60	60	15	15	25	25
Annual Program Savings Per Partcipant	(48)	(48)	(107)	(80)	(435)	(435)	(161)	(161)	(495)	(495)
Net to Gross Ratio	1.00	0.90	1.00	0.60	1.00	0.58	1.00	0.58	1.00	0.58
Cost to Participant (Incremental Cost of Product)	$ 400	$ 600	$ 800	$ 800	$ 700	$ 1,700	$ 500	$ 500	$ 3,000	$ 3,000

Note: The Company provided an update to its cost benefit analysis based upon the Company's latest revised gas cost forecast and the results of the study the Company performed to respond to Requests CAPD Question 142 and CAPD Question 173.
Source: Response to CAPD Question 151, Attachment 151-2.

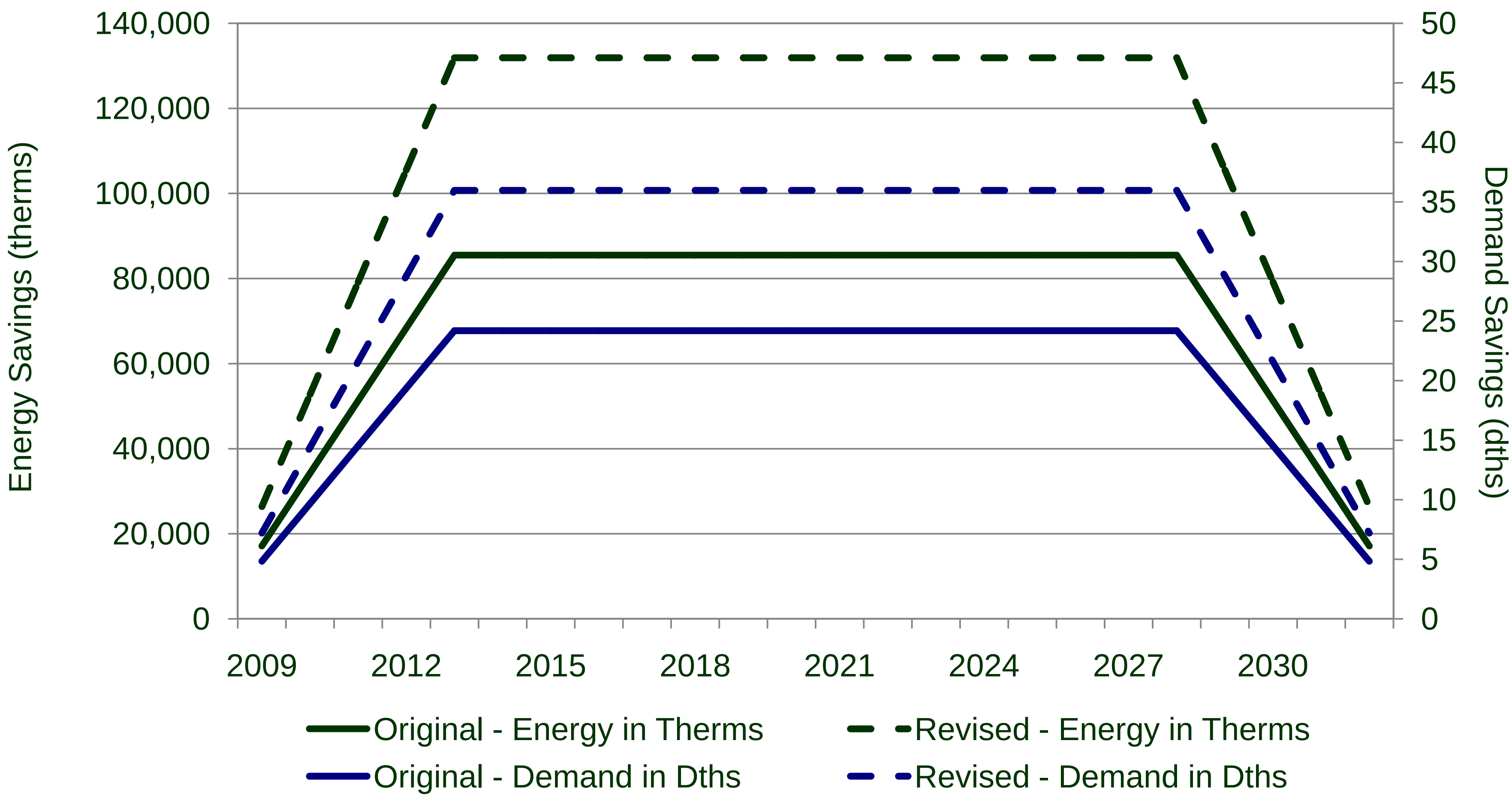
Chattanooga Gas Company
Effect of Kickback Assumptions – High Efficiency Furnace



Source: Response to CAPD Question 151, Attachments 151-1 and 151-2.

Chattanooga Gas Company
Effect of Kickback Assumptions – Tankless Water Heater

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-9



Source: Response to CAPD Question 151, Attachments 151-1 and 151-2.

Chattanooga Gas Company
Revised Results of Cost-Effectiveness Tests

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-10

	Residential Measures					Commercial Measures					
	Free Programmable Thermostats	Low Income Weatherization	High Efficiency Furnace/ Boiler Incentive	Tankless Water Heater Incentive	High Efficiency Storage Water Heater Incentive	Food Service Equipment	High Efficiency Furnace/ Boiler Incentive	Tankless Water Heater Incentive	High Efficiency Storage Water Heater Incentive	Booster Water Heater Incentive	Total energySmart
Participants Test											
Total Benefits	$ 404,120	$ 412,967	$ 844,548	$ 363,358	$ 39,122	$ 499,525	$ 545,528	$ 695,077	$ 59,718	$ 265,577	$ 4,129,541
Total Costs	$ 544,776	$ 111,182	$ 694,605	$ 615,072	$ 23,162	$ 539,274	$ 485,347	$ 458,383	$ 33,705	$ 337,046	$ 3,842,552
Net Benefit	$ (140,656)	$ 301,785	$ 149,943	$ (251,714)	$ 15,959	$ (39,749)	$ 60,182	$ 236,694	$ 26,014	$ (71,469)	$ 286,989
Benefit/Cost Ratio	**0.74**	**3.71**	**1.22**	**0.59**	**1.69**	**0.93**	**1.12**	**1.52**	**1.77**	**0.79**	**1.07**
Rate Impact Measure Test											
Total Benefits	$ 709,242	$ 255,523	$ 529,102	$ 187,194	$ 19,807	$ 328,573	$ 315,013	$ 575,654	$ 40,617	$ 249,883	$ 3,210,608
Total Costs	$ 497,089	$ 468,788	$ 950,087	$ 408,703	$ 44,779	$ 589,497	$ 609,214	$ 841,443	$ 70,483	$ 329,976	$ 5,010,061
Net Benefit	$ 212,153	$ (213,265)	$ (420,985)	$ (221,509)	$ (24,972)	$ (260,923)	$ (294,201)	$ (265,789)	$ (29,865)	$ (80,094)	$ (1,799,452)
Benefit/Cost Ratio	**1.43**	**0.55**	**0.56**	**0.46**	**0.44**	**0.56**	**0.52**	**0.68**	**0.58**	**0.76**	**0.64**
Total Resource Cost Test											
Total Benefits	$ 709,242	$ 255,523	$ 529,102	$ 187,194	$ 19,807	$ 328,573	$ 315,013	$ 575,654	$ 40,617	$ 249,883	$ 3,210,608
Total Costs	$ 556,158	$ 111,414	$ 696,414	$ 615,826	$ 23,438	$ 541,162	$ 486,621	$ 458,949	$ 33,846	$ 337,282	$ 4,061,111
Net Benefit	$ 153,084	$ 144,109	$ (167,311)	$ (428,632)	$ (3,632)	$ (212,589)	$ (171,608)	$ 116,705	$ 6,771	$ (87,400)	$ (850,503)
Benefit/Cost Ratio	**1.28**	**2.29**	**0.76**	**0.30**	**0.85**	**0.61**	**0.65**	**1.25**	**1.20**	**0.74**	**0.79**
Program Administrator Test											
Total Benefits	$ 709,242	$ 255,523	$ 529,102	$ 187,194	$ 19,807	$ 328,573	$ 315,013	$ 575,654	$ 40,617	$ 249,883	$ 3,210,608
Total Costs	$ 120,337	$ 183,682	$ 435,937	$ 181,657	$ 20,129	$ 181,646	$ 304,616	$ 135,386	$ 20,366	$ 22,709	$ 1,806,467
Net Benefit	$ 588,904	$ 71,841	$ 93,165	$ 5,537	$ (323)	$ 146,927	$ 10,397	$ 440,268	$ 20,251	$ 227,174	$ 1,404,142
Benefit/Cost Ratio	**5.89**	**1.39**	**1.21**	**1.03**	**0.98**	**1.81**	**1.03**	**4.25**	**1.99**	**11.00**	**1.78**

Source: Response to CAPD Question 151, Attachment 151-2.

Chattanooga Gas Company
Virginia Natural Gas Customer Participation

Program	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
90%+ Furnace	-	75	99	39	55	281	67	616
Free Thermostat	727	711	589	793	17	852	435	4,124
Programmable Thermostat Rebate	-	40	40	21	27	184	47	359
Seasonal Check-Up	-	22	31	1	-	4	65	123
Tank Style Water Heater	-	4	16	2	5	43	24	94
Tankless Water Heater	-	49	46	17	17	100	28	257
Low Income Weatherization	6	18	16	14	9	14	2	79
Total	**733**	**919**	**837**	**887**	**130**	**1,478**	**668**	**5,652**

Source: Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

Chattanooga Gas Company
Virginia Natural Gas Program Savings

Program	Quantity	Savings per Rebate	Total Savings
		---- (Ccf) ----	
90%+ Furnace	616	(60)	(36,960)
Free Thermostat	1,267	(13)	(16,471)
Programmable Thermostat Rebate	312	(13)	(4,056)
Seasonal Check-Up	123	(109)	(13,407)
Tank Style Water Heater	94	(43)	(4,042)
Tankless Water Heater	257	(100)	(25,700)
Low Income Weatherization	79	(196)	(15,484)
Energy Star Homes		(103)	-
Total	**2,748**	**(637)**	**(116,120)**

Source: Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

Chattanooga Gas Company
Virginia Natural Gas Program Expenditures

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
	($)									
Seasonal Checkup	$ -	$ -	$ -	$ 550	$ 775	$ 25	$ -	$ 100	$ 1,625	**$ 3,075**
Programmable Thermostats Rebate	$ -	$ -	$ -	$ 1,000	$ 1,000	$ 525	$ 675	$ 4,600	$ 1,175	**$ 8,975**
Low Income Weatherization	$ -	$ 80,000	$ -	$ -	$ -	$ -	$ 40,000	$ -	$ -	**$ 120,000**
Tank Water Heater	$ -	$ -	$ -	$ 600	$ 2,400	$ 300	$ 750	$ 6,450	$ 3,600	**$ 14,100**
Tankless Water Heater	$ -	$ -	$ -	$ 24,500	$ 23,000	$ 8,500	$ 8,500	$ 50,000	$ 14,000	**$ 128,500**
Space Heating Free Programmable	$ -	$ -	$ -	$ 37,500	$ 49,500	$ 19,500	$ 27,500	$ 140,500	$ 33,500	**$ 308,000**
Thermostats	$ -	$ -	$ 13,473	$ 13,175	$ 10,914	$ 14,694	$ 315	$ 15,788	$ 8,061	**$ 76,420**
Community Education & Outreach	$ -	$ 631	$ 13,146	$ 11,217	$ 16,109	$ 13,186	$ 11,851	$ 12,417	$ 15,813	**$ 94,370**
Air Filter Coupon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,192	**$ 2,192**
Administrative Costs	$ -	$ -	$ 2,622	$ 1,992	$ 3,486	$ 2,873	$ 2,955	$ 3,738	$ 86	**$ 17,752**
Other Expenses	$ 3,900	$ 3,900	$ 11,062	$ 11,062	$ 24,075	$ 24,075	$ 24,075	$ 24,075	$ 24,075	**$ 150,299**
Total	**$ 3,900**	**$ 84,531**	**$ 40,303**	**$ 101,596**	**$ 131,259**	**$ 83,678**	**$ 116,621**	**$ 257,668**	**$ 104,127**	**$ 923,683**

Source: Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

Chattanooga Gas Company
Virginia Natural Gas Revenue Decoupling Adjustments

		Revenue Deficiency to be Collected Through Adjustment Factor ($)	Targeted Sales	Booked Sales	Sales Difference
			------------- (Ccf) -------------		
Jan	$	1,526,271	36,831,558	36,302,500	(529,058)
Feb	$	942,456	29,721,803	26,661,280	(3,060,523)
Mar	$	(19,848)	19,529,199	22,262,870	2,733,671
Apr	$	1,211,770	13,461,446	9,061,550	(4,399,896)
May	$	541,755	6,374,643	4,103,150	(2,271,493)
Jun	$	187,784	3,275,567	2,682,620	(592,947)
Jul	$	85,616	3,261,364	2,445,740	(815,624)
Aug	$	110,491	2,909,196	2,475,681	(433,515)
Sep	$	94,729	3,624,844	3,239,170	(385,674)
Total	**$**	**4,681,024**	**118,989,620**	**109,234,561**	**(9,755,059)**

Source: Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

Chattanooga Gas Company
Comparison of Virginia Natural Gas and Chattanooga Cost-Effectiveness

	Chattanooga Gas Company - Residential Measures				
	Free Programmable Thermostats	Low Income Weatherization	High Efficiency Furnace/ Boiler Incentive	Tankless Water Heater Incentive	High Efficiency Storage Water Heater Incentive
Benefit-Cost Ratio					
Participants Test	2.49	3.08	1.66	1.94	2.32
Rate Impact Measure Test	1.81	0.57	0.79	0.65	0.65
Total Resource Cost Test	4.45	1.74	1.32	1.26	1.49
Program Administrator Test	20.56	1.06	2.11	1.76	1.74

	Virginia Natural Gas - Residential Measures					
	Seasonal Check-Up	Low Income Weatherization	Space Heating	Tankless Water Heater	Tank Water Heater	Energy Star
Benefit-Cost Ratio						
Participants Test	2.43	3.07	1.88	2.29	2.09	2.52
Rate Impact Measure Test	0.86	0.67	0.73	0.69	0.66	0.90
Total Resource Cost Test	2.10	2.07	1.38	1.58	1.37	2.26
Program Administrator Test	6.39	2.07	2.77	2.21	1.92	8.82

Source: Response to CAPD Question 151, Attachment 151-2; and Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

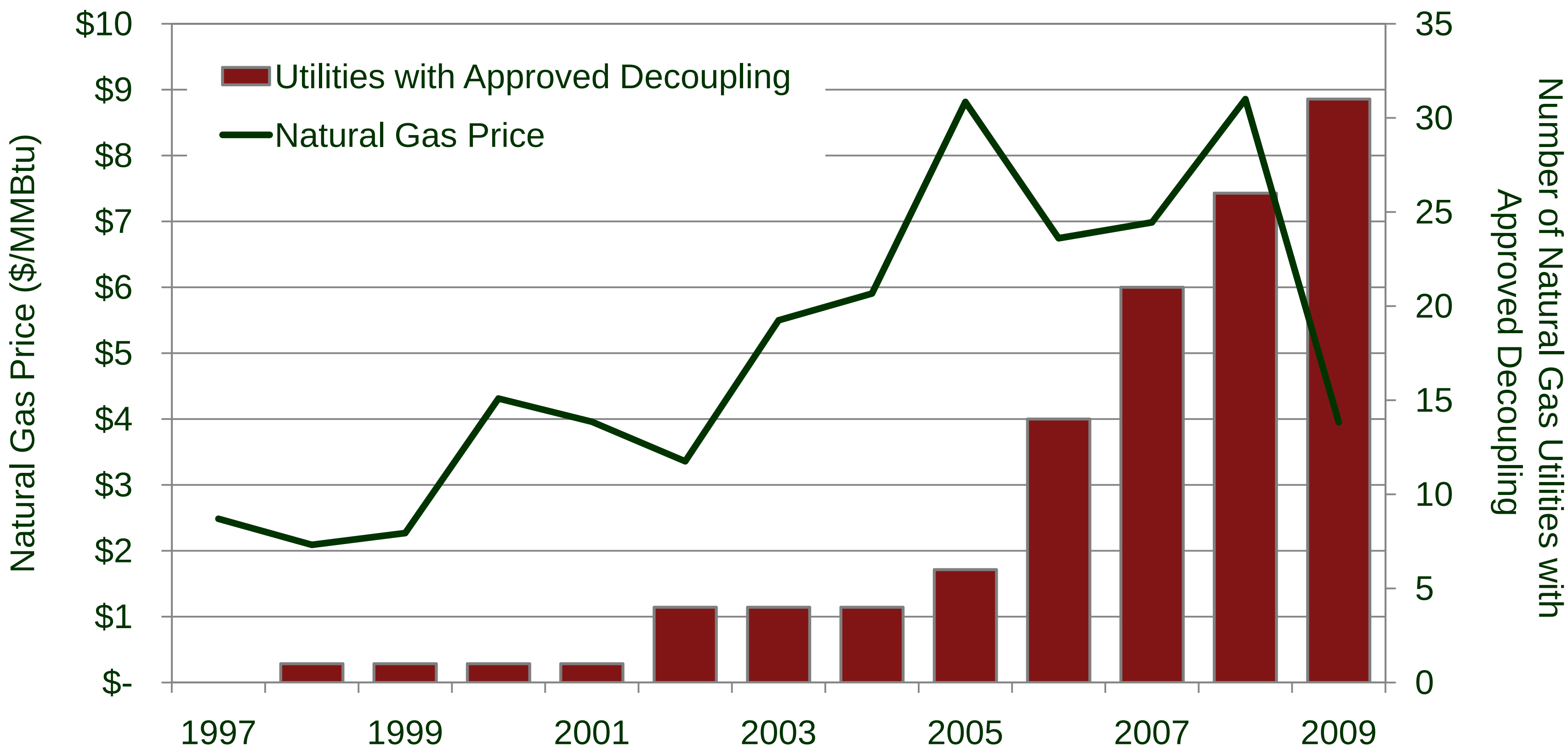
Chattanooga Gas Company
States with ARRA Funding and Decoupling

States with Decoupling			States without Decoupling		
State		**ARRA Funding ($)**	**State**		**ARRA Funding ($)**
Arkansas	$	9,593,500	Alabama	$	10,350,200
California	$	49,603,400	Alaska	$	9,593,500
Colorado	$	9,593,500	Arizona	$	9,593,500
Connecticut	$	9,593,500	Delaware	$	9,593,500
Hawaii	$	9,593,500	Florida	$	30,401,600
Idaho	$	9,593,500	Georgia	$	21,630,700
Illinois	$	21,834,600	Iowa	$	9,593,500
Indiana	$	14,052,400	Kansas	$	9,593,500
Maryland	$	9,593,500	Kentucky	$	10,427,000
Massachusetts	$	14,752,100	Louisiana	$	13,805,700
Michigan	$	19,599,600	Maine	$	9,593,500
Minnesota	$	10,644,100	Mississippi	$	9,593,500
Nevada	$	9,593,500	Missouri	$	12,568,100
New Jersey	$	14,400,700	Montana	$	9,593,500
New York	$	29,760,600	Nebraska	$	9,593,500
North Carolina	$	20,925,300	New Hampshire	$	9,593,500
Ohio	$	24,979,600	New Mexico	$	9,593,500
Oregon	$	9,593,500	North Dakota	$	9,593,500
Utah	$	9,593,500	Oklahoma	$	9,593,500
Vermont	$	9,593,500	Pennsylvania	$	23,574,800
Virginia	$	16,145,300	Rhode Island	$	9,593,500
Washington	$	10,645,900	South Carolina	$	9,593,500
Wisconsin	$	11,743,000	South Dakota	$	9,593,500
Wyoming	$	9,593,500	Tennessee	$	13,818,200
			Texas	$	45,638,100
			West Virginia	$	9,593,500
Total	**$**	**364,615,100**	**Total**	**$**	**345,303,900**

Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy, Energy Efficiency and Conservation Block Grants Program.

Chattanooga Gas Company
Natural Gas Price and Approved Decoupling

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-14



Source: Federal Reserve Bank of St. Louis.

Chattanooga Gas Company
Energy Efficiency Resource Standards

ID: Energy Plan sets conservation – DR and EE as priority resources

WA: pursue all cost effective conservation: ~10% by 2025

OR: IOU 2008 goals 34 MW; administered by Energy Trust OR

CA: 8% energy savings; 4,885 MW peak reduction by 2013 (from '04)

NV: EE up to 25% of RPS: ~5% electric reduction by 2015

UT: EE earns incentive credits in RE goal

CO: 11.5% energy savings by 2020 ~ 3,669 GWh (from '08)

NM: 10% retail electric sales savings by 2020 (from '05)

NE: Interim Energy Plan stresses multi-sector EE improvements

KS: Voluntary utility programs

OK: PSC approved quick-start DR utility EE and DR programs

TX: 20% of load growth by 2010, using average growth rate of prior 5 years

HI: 30% electricity reduction: ~4,300 GWh by 2030 (from '09)

MI: 1% annual energy savings from prior year's sales

MN: 1.5% annual savings based on prior 3-years average, to 2015

IA: 5.4% energy savings by 2020 ~ 1.5% annual

IL: reduce energy use 2% by 2015 and peak 0.1% from prior year

OH: 22% energy savings by 2025 (from '09); reduce peak 8% by 2018

KY: proposed RPS-EE to offset 18% of projected 2025 demand

ME: 30% energy savings; 100 MW peak electric reduction by 2020

VT: 11% energy reductions by 2011 (2% annual) administered by Efficiency VT

MA: 25% of electric load from DSR, EE by 2020: capacity and energy

NY: reduce electric use 15% by 2015 from levels projected in 2008

CT: 4% energy savings (1.5% annual) and 10% peak reduction by 2010 (from '07)

RI: reduce 10% of 2006 sales by 2022

NJ: BPU proceeding to reduce consumption, peak

DE: Sustainable Energy Utility charged with 30% energy reduction by 2015

PA: reduce use 3%; peak 4.5% by 2013 as % of 2009-10 sales

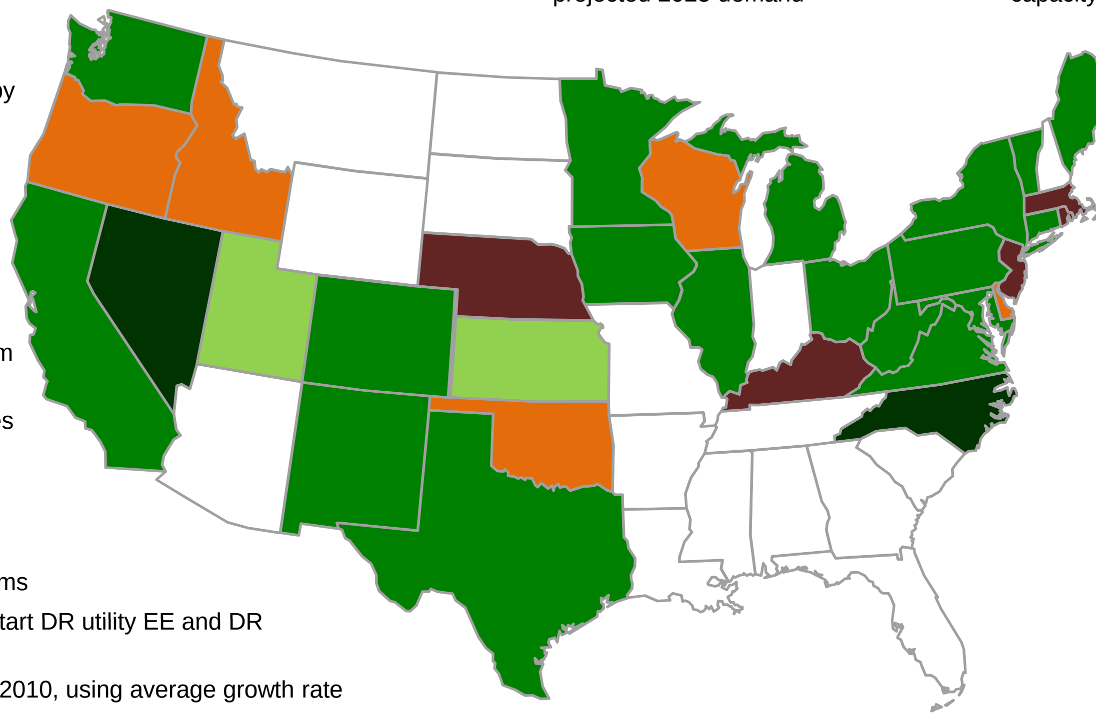
MD: reduce per capita electricity use and peak 15% by 2015 (from '07)

VA: reduce electric use 10% by 2022 (from '06)

WV: EE & DR earn one credit for each MWh conserved in the 25% by 2025

NC: EE to meet up to 25% of RPS by 2011

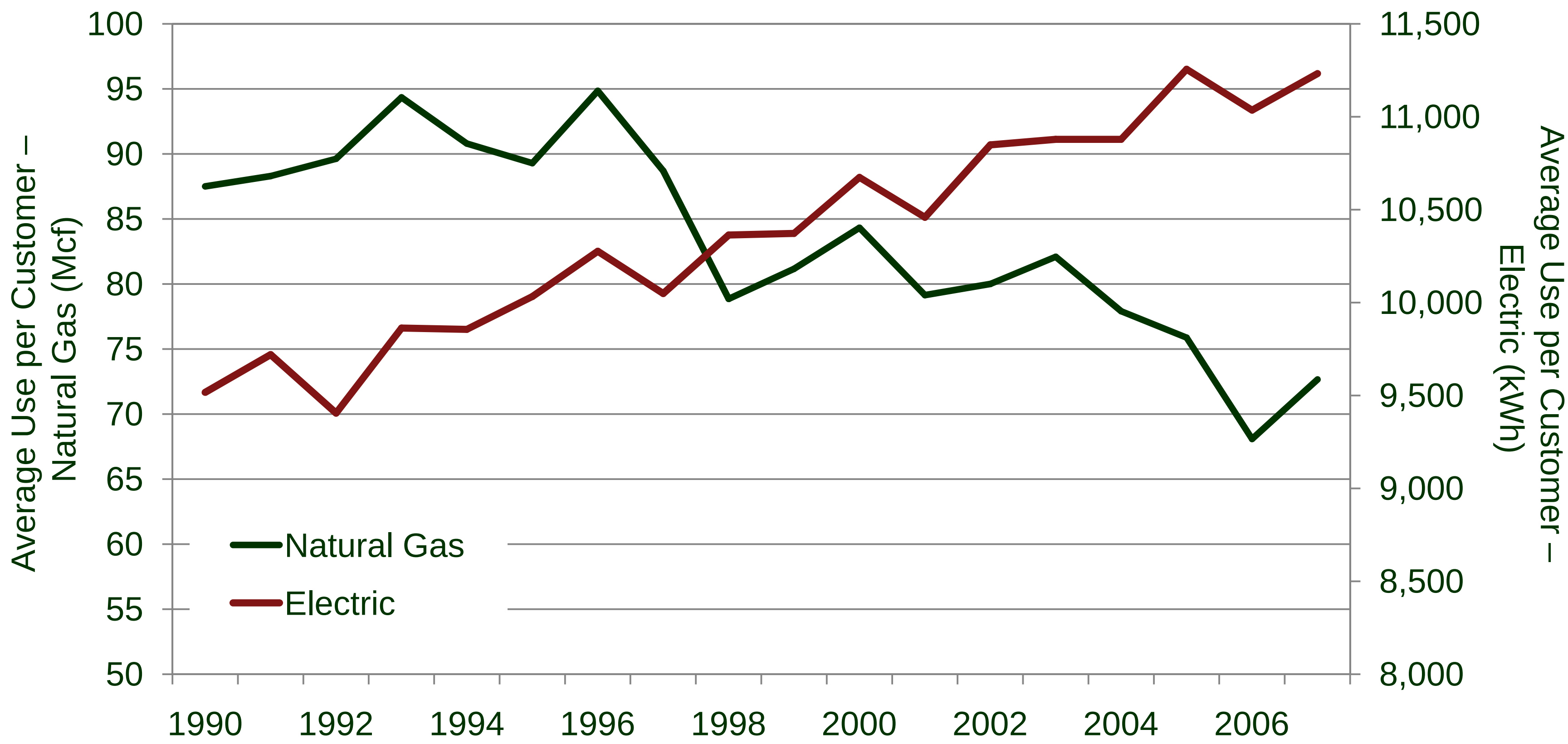
TVA: reduce energy use 25% and cut peak 1,400 MW by 2012 (from '08)



- EE as part of an RPS law or rule
- EERS by regulation or law (stand-alone)
- Voluntary standards (in or out of RPS)
- EE pending regulations, proposed or studied
- Other EE entity, rule or procurement order

Note: As of July 8, 2009
Source: Federal Energy Regulatory Commission

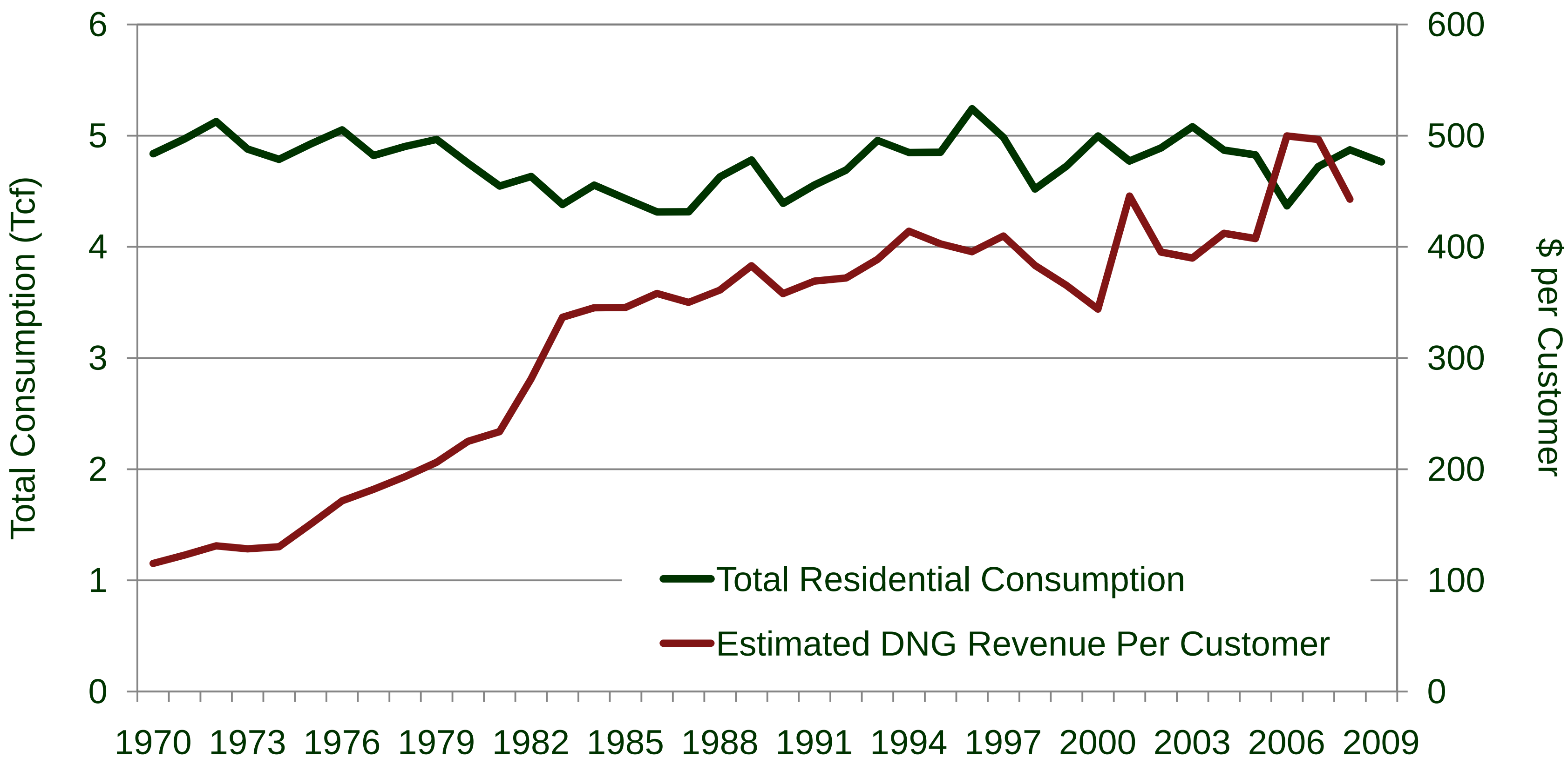
Chattanooga Gas Company
U.S. Residential Natural Gas and Electric Use Per Customer



Source: Energy Information Administration, U.S. Department of Energy.

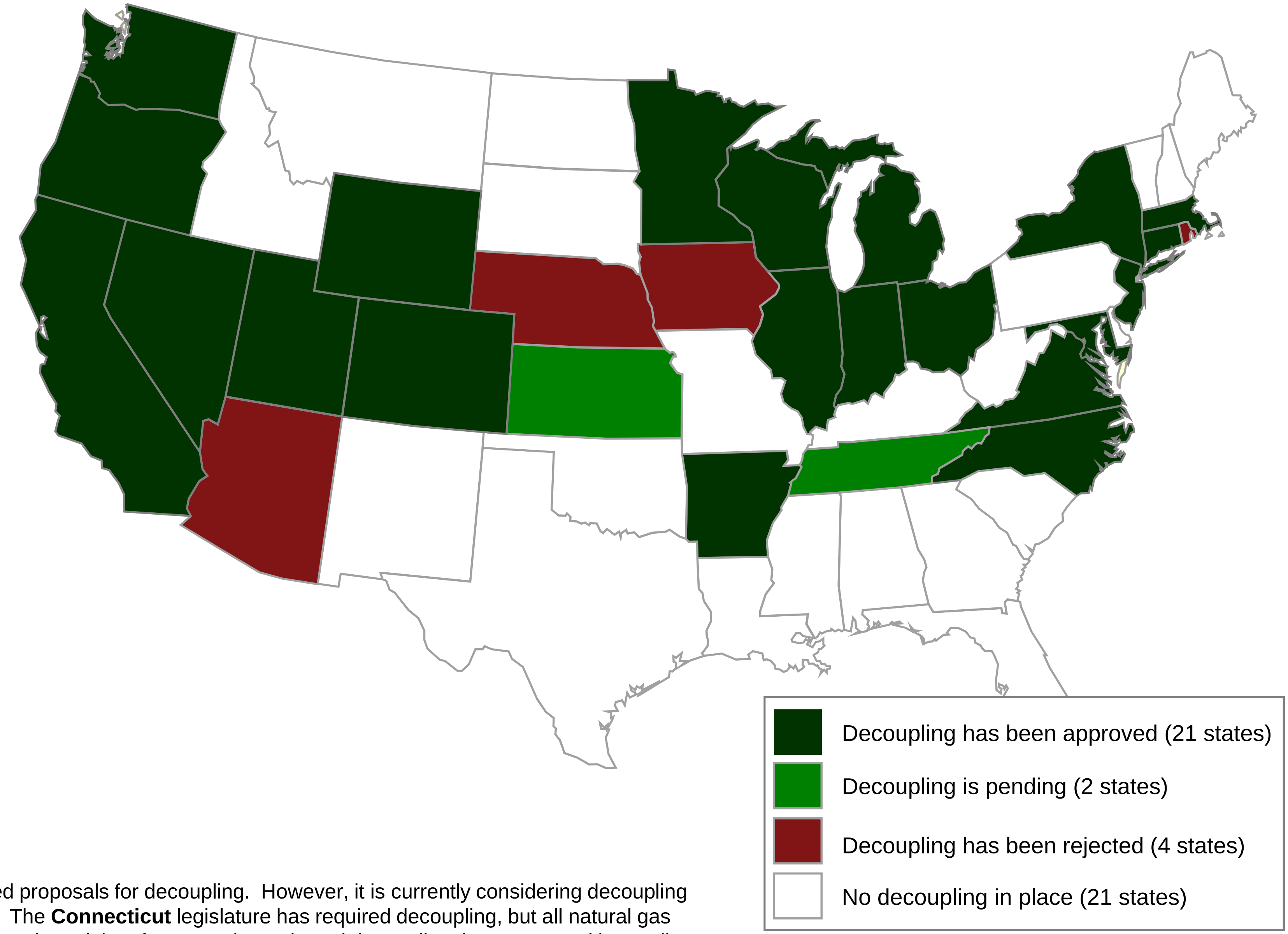
Chattanooga Gas Company
U.S. Residential Natural Gas Use
and Estimated DNG Revenue per Customer

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-17



Source: Energy Information Administration, U.S. Department of Energy.

Chattanooga Gas Company
Status of Natural Gas Decoupling



Notes:
Arizona has rejected proposals for decoupling. However, it is currently considering decoupling in a generic docket. The **Connecticut** legislature has required decoupling, but all natural gas proposals have been rejected thus far. **Iowa** has rejected decoupling, but a proposal is pending.

Chattanooga Natural Gas Company
Incremental Cost Summary

Witness: Dismukes
Docket No. 09-00183
Exhibit DED-19

Cost Category	Average New Customer Cost	Average Embedded Cost
Meters	$ 541	$ 197
Services	$ 904	$ 902
Regulators	$ 57	$ 57
Mains	$ 1,605	$ 1,592
Other	$ (180)	$ -
Total	$ 2,926	$ 2,747

Source: Response to CAPD Question 195, Attachment 195-1.

Chattanooga Gas Company
Incentive Mechanisms for Energy Efficiency

State	Description
Arizona	Arizona Public Service is permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from EE programs. The performance incentive is capped at 10% of total DSM expenditures.
California	The EE Risk-Reward Incentive Mechanism allows utilities to earn an incentive on EE programs. Revenue from eligible EE programs is the product of the Earnings Rate and net benefits. If the ER is 12% if the utility achievement toward CPUC goals is greater than 100%; 9% if achievement is between 85% and 100%. If the achievement is is less than 65% the utility pays a penalty. The dead-band is 65% to 85%. Net benefits are calculated as two-thirds of hte TRC Net Benefit and one-third of th PAC Net Benefit.
Colorado	Electric and natural gas utilities are allowed to earn a profit on DSM expenditures as long as the utility achieves at least 80% of its energy savings goal in any one year. The utilities are also allowed to recover the costs of DSM programs. The incentive is tied to energy savings achieved and the net economic benefits of the programs. For electric utilities the incentive is capped at 20% of DSM expenditures. For natural gas utilities, the incentive bonus is capped at 25% of the expenditures or 20% of the net economic benefits of the DSM programs, whichever amount is lower.
Connecticut	The DPUC requires annual hearings to review the past year's results relative to established goals and determines a performance incentive for distribution utilities for achieving or exceeding those goals. The incentive can range from 1% to 8% of program costs. The minimum threshold of 70% of goals earns the minimum 1% incentive; 100% earns 5%; and 130% earns 8%.
Georgia	By statute, utilities may recover costs as well as an additional sum for approved DSM programs. Georgia Power an additional sum of 15% of the NPV of the net benefits of its program, contingent on the program achieving at least 50% of projected participation levels.
Idaho	Idaho Power (IPC) was approved for a 3-year pilot incentive program beginning in January 2007. IPC receives an incentive if the market share of homes constructed under the ENERGY STAR Homes Northwest program exceeds a target percentage of new homes constructed. The market share goals were 7% in 2007, 9.8% in 2008, and 11.7% in 2009. Incentives are capped at 10% of program net benefits and IPC is penalized if it does not meet a minimum market share percentage. In March 2009, IPC requested that the pilot be discontinued retroactively as of January 1, 2009 due to current economic conditions.

Chattanooga Gas Company
Incentive Mechanisms for Energy Efficiency

State	Description
Indiana	By statute, either shared savings or adjusted/bonus ROE mechanism are allowed as DSM incentives. Duke Energy has submitted a proposal for an avoided cost recovery charge for EE programs. Vectren Energy Indiana, Northern Indiana Public Service Company, and Indianapolis Power and Light have also filed DSM plans requesting performance incentives.
Kansas	Kansas statute allows a return of 0.5% to 2% on EE investments above the allowed rate of return.
Kentucky	Utilities are allowed to recover the full costs of DSM programs through rates and incentives are designed to provide financial rewards for utilities and encourage implementation of cost-effective DSM programs. Duke Energy and Kentucky Power (AEP) have shared savings mechanisms that allow them to receive an incentive of up to 10% of program costs for exceeding goals.
Massachusetts	Utilities may earn about 5% of program costs for EE programs that meet established program goals. The incentive structure is determined on a program-by-program basis but generally utilizes a three-tiered structure. The first “design performance” level is defined as performance that a Program Administrator expects to achieve in implementing its EE programs. The second “threshold performance” level is 75% of the design level. The third “exemplary performance” level is 125% of the design level. Incentives are awarded only if a program achieves the threshold level or above.
Michigan	Recent legislation contains two provisions whereby utilities can receive an economic incentive for implementing EE programs. (1) a utility may request that EE program costs be capitalized and earn a normal rate of return; and (2) a utility may request a performance incentive for shareholders if the utilities exceed the annual energy savings target. Performance incentives cannot exceed 15% of the total cost of the EE programs.
Minnesota	Utility incentives on a percentage of net benefits (as measured by the utility cost-effectiveness test) created by their actual investments in energy conservation. As the percentage of energy-savings goal achieved increases, so does the percentage of net benefits awarded. The incentive is calibrated such that at 150% of the energy-savings goal, the utility would receive about 30% of the utility’s conservation expenditure budget as required by statute. Utilities are also rewarded for delivering their programs more cost-effectively as more net benefits are created when actual costs are lowered.
Montana	State statute allows the PSC to add 2% to the authorized rate of return for DSM investments.

Chattanooga Gas Company
Incentive Mechanisms for Energy Efficiency

State	Description
Nevada	Utilities may earn up to 500 basis points above allowed ROE for applicable, approved DSM costs. To earn the incentive, a utility must follow an approved plan and budget. The utility's debt-to-equity ratio is applied to the fraction of capitalized DSM costs, and then the extra 5% ROE is applied to that amount.
New Hampshire	There are two separate incentives in NH: (1) The cost-effectiveness incentive is awarded for programs that achieve a cost effectiveness ratio of 1.0 or higher. The incentive is calculated as 4% of the planned EE budget times the ratio of actual to planned cost effectiveness. (2) The energy savings incentive is awarded when actual lifetime kWh savings are greater than or equal to 65% of projected savings. The incentive is 4% of the planned EE budget times the ratio of actual to planned energy savings. Target incentive amounts are calculated separately for residential and commercial/industrial sectors and are cappped at 12% of the planned sector budgets.
New York	Performance incentives may be included in utility rate cases. Aggregate incentives are capped at $40M per year statewide and targets will be set for each year at the time of review for the EE plans.
North Carolina	State law allows for a utility to propose incentives for DSM or EE for consideration. Progress Energy Carolina's is allowed an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs.
Ohio	Duke Energy's "Save-a-Watt" program includes an incentive of 50% of the NPV of the avoided costs for energy conservation and 75% of the NPV of the avoided costs for demand response. Demand response programs are viewed by the parties as having a useful life of 1 year, while energy conservation programs have useful lives of up to 15 years.
Oklahoma	A shared savings program has been approved for Public Service Oklahoma that allows for 1) an incentive of 25% of net savings for programs for which energy savings can be estimated: and 2) an incentive of 15% of the costs for programs that do not produce savings such as educational or marketing programs.
Rhode Island	National Grid's shareholder incentive mechanism includes two components: performance-based metrics for specific program achievements, and kWh savings targets by sector. Program performance metrics are established for each individual program, such as achieving specific savings or a certain market share for the targeted EE technology. If National Grid achieves the savings goal, it receives 4.4% of the eligible budget. The threshold performance level is 60% of the savings goal. Once the threshold level has been reached, the utility has the ability to earn an additional incentive per kWh saved up to 125% of target savings.

Chattanooga Gas Company
Incentive Mechanisms for Energy Efficiency

State	Description
South Carolina	Progress Energy Carolina's incentive mechanism allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs.
Texas	A utility is awarded a performance bonus (share of net benefits) if it exceeds its demand reduction goal within the prescribed cost limit. The performance bonus is based on the utility's EE achievements for programs implemented in the previous year. A utility that exceeds 100% of its demand reduction goal receives a bonus of 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, up to 20% of the utility's program costs. Additionally, a utility that meets at least 120% of its demand reduction goal with at least 10% of its savings achieved through Hard-to-Reach programs (which benefit customers with an annual household income at or below 200% of the federal poverty guidelines) can receive an additional bonus equal to 10% of the regular performance bonus.
Vermont	The operator of Efficiency Vermont, VEIC, is eligible to receive a performance incentive for meeting or exceeding performance goals established in its contracts. The contractor does not receive compensation until the achievement has been confirmed by the DPS. In its initial contract (2000-2002), VEIC could earn up to $795,000 (~ 2% of the overall EE budget) over the three-year contract period. Subsequent contracts have set "stretch goals" to encourage program growth.
Washington	In Washington, Cascade Natural Gas and Avista's (natural gas) incentives are part of their decoupling mechanisms. Recovery of deferred revenues is tied to meeting certain annual savings thresholds. If the company achieves 100% of its EE target, it recovers 90% of decoupling deferrals. The recovery threshold is 70%.
Wisconsin	Utilities can propose incentives as part of their rate cases. Wisconsin Power & Light (Alliant Energy) is allowed to earn the same rate of return on its investments in EE made through its "Shared Savings" program for C/I customers as it earns on other capital investments (e.g., power plant construction.)

Source: Commission Orders; The Edison Foundation, Institute for Electric Efficiency; The Regulatory Assistance Project; and American Council for an Energy-Efficient Economy.

Chattanooga Gas Company
Recommended Natural Gas Decoupling Rate Adjustment

Actual vs. Target DSM Savings	Avista Allowed Deferral Percentages Prior	Avista Allowed Deferral Percentages Current	Proposed CGC Deferral Percentages
<70	60%	15%	9%
>80 and	70%	25%	14%
>90 and	80%	35%	19%
100	90%	45%	24%

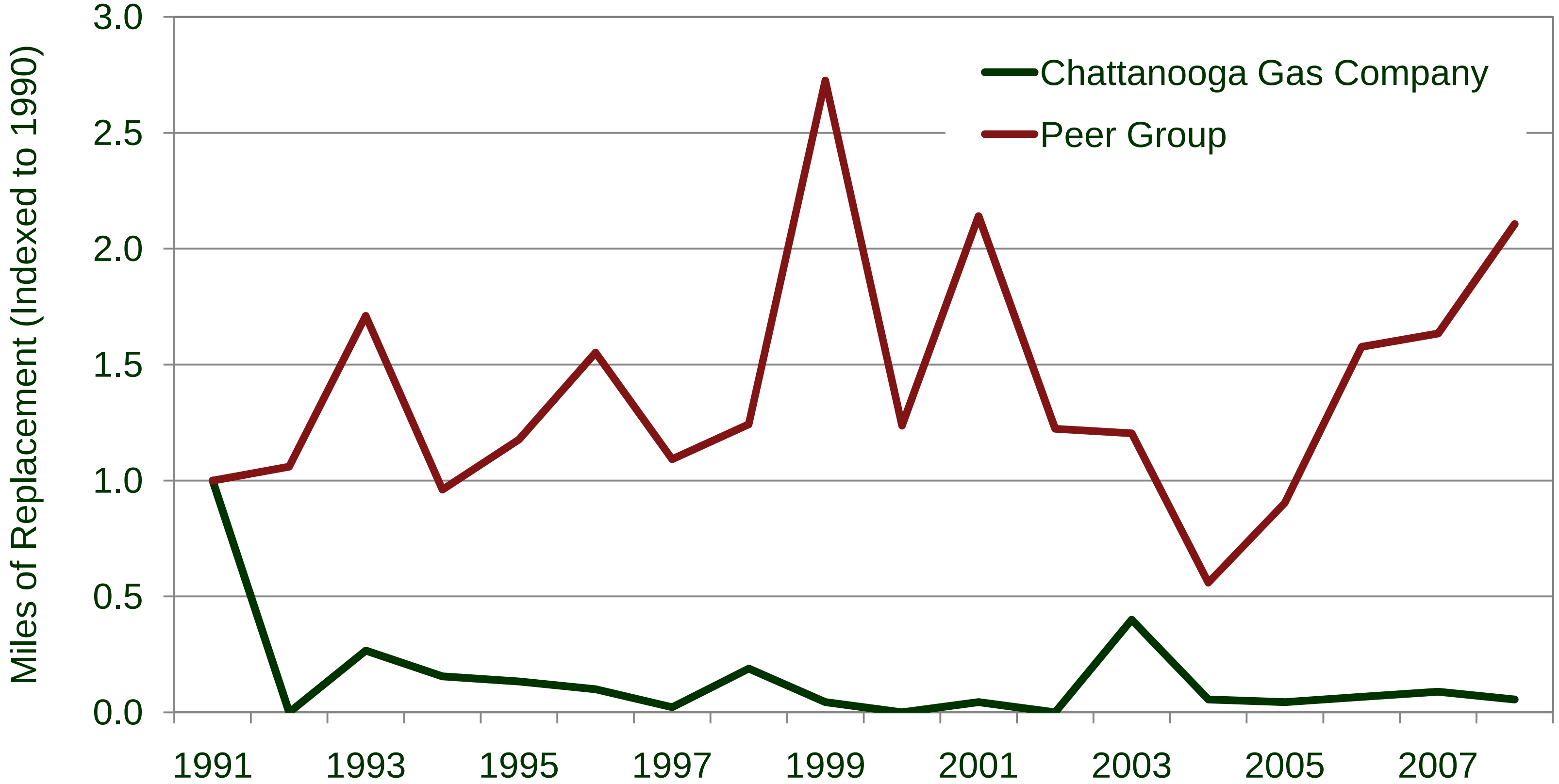
Source: Docket 090134 and UG 090135, consolidated. *Washington Utilities and Transportation Commission v. Avista Corporation, d./b./a. Avista Utilities*. Order 10: Final Order Rejecting Tariff Filling; Approving and Adopting Multi-Party Partial Settlement Stimulation; Deferring Lancaster Costs; Extending Decoupling Mechanism; Authorizing Tariff Filing; and Requiring Compliance Filing, December 22, 2009.

Chattanooga Gas Company
Comparison of Unprotected Pipe (2008)

	Miles of Unprotected Pipe[1]	Total Miles of Distribution Pipe	Percent of Total
	----- (miles) -----		(%)
Chattanooga Gas Co (TN)	**67**	**1582**	**4.2%**
Alabama Gas (AL)	1,911	10,725	17.8%
Mobile Gas Service (AL)	212	2,238	9.5%
Arkansas Western Gas (AR)	437	4,378	10.0%
Atlanta Gas Light (GA)	466	30,647	1.5%
Entergy Gulf States (LA)	25	1,708	1.5%
Entergy New Orleans (LA)	282	1,602	17.6%
Atmos Energy Corp (MS)	19	6,241	0.3%
Piedmont Natural Gas Co (NC)	-	14,664	0.0%
Public Service Corporation of NC (NC)	-	9,908	0.0%
Piedmont Natural Gas Co (SC)	-	3,489	0.0%
South Carolina Electric & Gas (SC)	-	8,281	0.0%
Atmos Energy Corp (TN)	70	3,168	2.2%
Centerpoint ENTEX (TX, LA, MS)	14	36,670	0.0%
Roanoake Gas Company (VA)	76	968	7.9%
Virginia Natural Gas (VA)	506	5,195	9.7%
Total Peer Group	**4,018**	**139,883**	**5.2%**

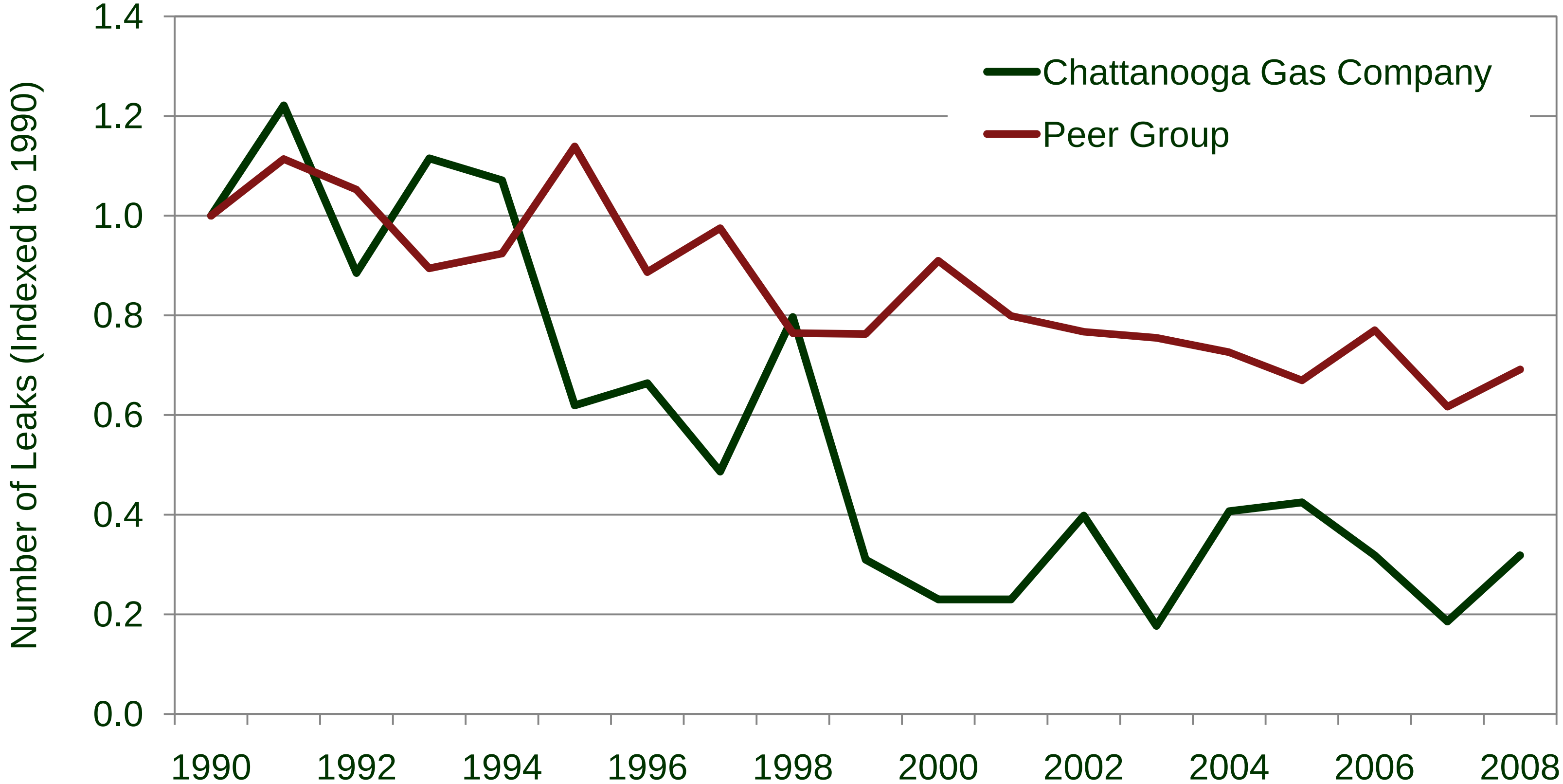
Note: [1]Includes steel uprotected bare, steel unprotected coated and cast iron pipe.
Source: Office of Pipeline Safety, U.S. Department of Transportation.

Chattanooga Gas Company
Comparison of Unprotected Pipe



Note: [1]Includes steel uprotected bare, steel unprotected coated and cast iron pipe.
Alabama Gas, Virginia Natural Gas and Roanoake Gas Company were indexed to 1991; Entergy Gulf States was indexed to 1999. Also, Atmos Energy (MS) was not included in the analysis due to data inconsistencies.
Source: Office of Pipeline Safety, U.S. Department of Transportation.

Chattanooga Gas Company
Comparison of Corrosion Related Leaks



Note: Roanoake Gas Company wasindexed to 1991 and Entergy Gulf States was indexed to 1992.
Source: Office of Pipeline Safety, U.S. Department of Transportation.