PUBLIC VERSION

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BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

In the Matter of the Petition of	)	
Piedmont Natural Gas Company, Inc.	)	
to Implement a Margin Decoupling	)	DOCKET NO. 09-00104
Tracker (MDT) Rider and Related	)	
Energy Efficiency and Conservation	)	
Programs	)	

PRE-FILED DIRECT TESTIMONY AND EXHIBITS OF

DAVID E. DISMUKES, PH.D.

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

DECEMBER 4, 2009

PUBLIC VERSION

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 6455 Overton Street, Baton Rouge, Louisiana.

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. 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 14 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 Margin Decoupling Tracker ("MDT") and Energy Efficiency Program proposals filed by Piedmont Natural Gas, Inc. ("Piedmont" or "the Company") on July 16, 2009 before the Tennessee Regulatory Authority ("TRA" or "Authority").

Q. HAVE A SERIES OF ISSUES BEEN DEFINED FOR THIS PROCEEDING?

A. Yes. In the *Order Granting Intervention, Determining Issues, and Establishing Procedural Schedule* issued October 13, 2009, the Hearing Officer identified the following five issues as pertinent to the resolution of the Company's petition:

Issue 1: What is the most appropriate mechanism, or financial incentive, to insure that Piedmont's financial incentives are aligned with the state's energy conservation policy as set out in 2009 Public Act 531, Section 53?

Issue 2: If such mechanism or incentive is adopted, what is the appropriate customer usage level and/or margin to be used as the benchmark for Piedmont's proposed decoupling mechanism?

Issue 3: Prior to implementing a decoupling mechanism, should Piedmont's earnings be evaluated?

Issue 4: Does the implementation of a decoupling mechanism lower the business risk for Piedmont, thereby justifying an adjustment to its rate

of return? If so, what method or evaluation tools should be utilized to quantify an appropriate adjustment to the rate of return?

Issue 5: Should Piedmont 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 that closely follow the issues outlined by the Hearing Officer:

- Section II: Summary of Recommendations
- Section III: Overview of the Company's Proposals
- Section IV: Appropriate Mechanism to Align Piedmont's Financial Incentives with the State's Energy Efficiency Policy (Issue 1)
- Section V: Appropriate Billing Determinants, Benchmarks and Ratepayer Protection Mechanisms Should Decoupling Be Accepted (Issue 2)
- Section VI: Earnings, Rate Case Evaluation and Revenue Decoupling (Issue 3)
- Section VII: Effect of Decoupling on Business Risk (Issue 4)
- Section VIII: Energy Efficiency Program Metrics (Issue 5)
- Section IX: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR GENERAL RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED MARGIN DECOUPLING TRACKER?

A. I recommend that the TRA reject the Company's proposed Margin Decoupling Tracker ("MDT" or "revenue decoupling proposal") for the following reasons:

- The Company's MDT would transfer a considerable amount of sales risk away from shareholders and towards ratepayers with virtually no reciprocal, nor proportional, benefits.
- The Company's revenue decoupling proposal includes virtually 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. 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.
- If the TRA would like to actively promote energy efficiency, I recommend that a performance-based mechanism that rewards Piedmont for greater-than-average success at achieving its energy efficiency potentials be adopted. Such an approach, however, cannot be adopted in this proceeding given the deficiency in the Company's energy efficiency filings.

If the TRA decides to move forward with an incentive-based approach, I recommend that it direct the Company make a future incentive-based filing that ties rewards to the Company's energy efficiency performance. This incentive-based filing should also include a comprehensive and documentable portfolio of energy efficiency programs.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes, if the TRA decides to adopt the Company's MDT, I recommend that it direct the Company to modify and re-file its proposal within the context of a general rate case. The minimum filing requirements for this rate case should include at least the following:

- The Company's determination of its proposed initial target revenues (margins) per customer for each rate class;
- The factors that the Company proposes to use to annually adjust its target revenues (margins) for each rate class;
- The manner in which the Company's proposed mechanism treats customers receiving new distribution service during a particular year, to the extent that the Company determines that the costs of providing service to new customers differs from the costs of providing service to existing customers;
- A tariff showing the manner in which the Company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;

- Include a total revenue decoupling account balance cap that is no greater than 2.0 percent of total base revenues;
- An analysis of how changes in risk resulting from the adoption of revenue decoupling have been taken into consideration in the determination of its proposed Return on Equity ("ROE");
- A full analysis of the potential and cost-effective energy efficiency opportunities in its service territory with supporting documentation on how these estimates have been developed; and
- A complete energy efficiency plan that includes cost effectiveness findings for each major energy efficiency measure/program being proposed and a proposed energy efficiency/revenue decoupling review process including goals, targets, and benchmarks.

Q. WHAT IF THE TRA DECIDES TO ADOPT REVENUE DECOUPLING WITHIN THIS PROCEEDING AND NOT A FULL RATE CASE?

A. Then I recommend the TRA modify the Company's current proposal in the following manner:

- Utilize the billing determinants estimated with more contemporaneous load and weather information that is provided in Exhibit DED-7.
- 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 only those amounts in excess of the recent

changes in the Company's Use Per Customer ("UPC"). Revenue recovery should only occur if UPC changes by more than 0.9 percent per year and then it should be restricted to the difference between the actual UPC percent change and a 0.9 percent threshold level.

- 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 filings with the Authority which are in the same format as provided in North Carolina. In addition, the Company

should make annual filings 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.

- The Company should be required to develop performance metrics and report these metrics to the TRA annually.
- To the extent there is a contested rate case or earnings review within the three year review period, the TRA should also examine the merits, and any potential modifications, of the MDT in that proceeding.

III. OVERVIEW OF THE COMPANY'S PROPOSALS

Q. WOULD YOU PLEASE OUTLINE THE COMPANY'S REVENUE DECOUPLING TRACKER PROPOSAL?

A. Yes. The Company is proposing a revenue decoupling mechanism, called the Margin Decoupling Tracker ("MDT") mechanism, that is purportedly "designed to align the financial interests of Piedmont's customers and shareholders with respect to the conservation and efficient use of natural gas by Piedmont's residential customers."[1] The Company states the tracker is designed to allow the Company to recover the "approved per customer margin found to be just and reasonable and established by the Authority in Piedmont's last general

[1] Piedmont Petition, p. 3.

rate proceeding."[2] Piedmont claims the mechanism will eliminate the negative incentives inherent in its current volumetric rate structure that restrain the Company from encouraging energy efficiency and conservation among its customers.[3] Piedmont also points to both Federal and State legislation promoting policies of energy conservation and energy efficiency.[4]

Q. CAN YOU IDENTIFY THE RECENT FEDERAL LEGISLATION SUPPORTING GREATER ENERGY EFFICIENCY IMPLEMENTATION?

A. Recently, the American Recovery and Reinvestment Act of 2009 ("ARRA") was passed by Congress and signed into law. 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:

> . . . 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.[5]

Q. DID TENNESSEE ADOPT SIMILAR LEGISLATION?

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[2] Ibid., p.4.
[3] Ibid., p. 4-5.
[4] Ibid., p. 2-3
[5] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 § 410(a), 123 Stat. 147 (2009).

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:

> . . . that the Tennessee regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the authority has rate making authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.[6]

Q. HAS THE COMPANY IDENTIFIED ANY OTHER MOTIVATION, OUTSIDE FEDERAL AND STATE LEGISLATION, TO SUPPORT ITS PROPOSAL?

A. Yes. The Company believes that its opportunity to collect revenues is "highly subject" to changes in customer usage since its current rate structure recovers the majority of fixed costs through volumetric rates. This volumetric rate design, according to the Company, creates strong incentives to promote maximum consumption by its customers[7] and makes it "…difficult for Piedmont to actively promote customer conservation and energy efficiency consistent with its own financial interests."[8]

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

A. The Company's proposed MDT will be calculated on a bi-annual basis and applied to monthly residential customer bills during two different collection

[6] Tenn. Code Ann. § 65-4-126.
[7] Piedmont Petition, pp. 3-4.
[8] Ibid., p. 4.

periods. The first calculation period will run from August to December of each year. Surcharges (or credits) resulting from the balance in the Margin Deferred Account for this period will be collected during the following April through October (first collection period). The second calculation period runs from January to July, with surcharges (or credits) from the margin deferrals collected during the following November through March (second collection period).[9]

Q. HOW WILL THE MARGIN DEFERRALS BE RECORDED?

A. The margin deferrals will be calculated at the end of each month for each residential rate schedule as the weather normalized difference between the actual and allowed margin. Interest will be applied to all balances on a monthly basis up to the time in which they are applied to customer bills. The balances will be collected during the true-up period on a volumetric basis. Each collection period will have a volumetric surcharge that is based upon each periods' total balance divided by allowed (test year) normalized sales.[10]

Q. WHY IS THE COMPANY PROPOSING TO CALCULATE, AND COLLECT, ITS DEFERRED MARGINS ON A WEATHER NORMALIZED BASIS?

A. The Company is proposing to calculate its margin deferrals and volumetric-based collections on a weather-normalized basis since it is also proposing to maintain its Weather Normalization Adjustment ("WNA") mechanism. Thus, weather-related changes in sales will be collected through the WNA while all other factors leading to sales differences will be collected

[9] Piedmont Petition, Exhibit A.
[10] Ibid.

through the Company's revenue decoupling mechanism. This proposal differs somewhat from how decoupling has been implemented for Piedmont's operations in other states.

Q. HOW ARE THESE MECHANISMS APPLIED TO PIEDMONT'S OPERATIONS IN OTHER STATES?

A. The Company's WNA was discontinued in North Carolina in 2005 when it adopted revenue decoupling. The Company's revenue decoupling mechanism in North Carolina is calculated on a non-weather normalized basis: meaning that all changes in sales (weather and non-weather-related), are trued-up through the revenue decoupling process. The Company appears to acknowledge 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]." [11] According to the Company, the WNA 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.[12]

IV. MECHANISM TO ALIGN PIEDMONT'S FINANCIAL INCENTIVES WITH THE STATE'S ENERGY EFFICIENCY POLICY (ISSUE 1)

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

[11] Response to TRA Data Request 2-5.
[12] Ibid.

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?

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 "trued-up" periodically to a "normalized margin." 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. WHO TRADITIONALLY BEARS THE RISK OF CHANGES IN SALES REVENUE?

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. 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 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. 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[13] and (2) the significant acceleration of state-driven energy efficiency ("EE") goals and targets. Exhibit DED-1 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

[13]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.

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-2 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 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. Exhibit DED-3 provides 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 that include 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.

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.[14] 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?

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.[15] 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)

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

[15] Ibid, p. 5.

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.[16] Only 43 percent of the decrease in residential UPC was attributable to longer-term structural changes in efficiency and appliance stock turn-over.[17]

Q. HOW SIGNIFICANT HAVE THE COMPANY'S REVENUE LOSSES BEEN FROM THE PROMOTION OF ITS DSM PROGRAMS?

A. The Company has experienced no historic revenue losses due to the promotion of energy efficiency since, prior to this filing, the Company has had no meaningful programs.[18] As part of this filing, the Company has included three relatively modest, residential energy efficiency programs. These programs represent very small commitments to energy efficiency on an order of magnitude that is considerably less than other leading natural gas distribution companies.

Q. IS THE COMPANY ANTICIPATING SIGNIFICANT REVENUE LOSSES FROM THE PROMOTION OF THESE THREE NEW ENERGY EFFICIENCY PROGRAMS?

A. No, the Company anticipates total annual savings of some 66.71 dekatherms ("Dths") per year from its proposed energy efficiency programs.[19] Expenditures for these programs are anticipated to run $500,000 annually.[20] Total natural gas savings from these programs are anticipated to be no more than 0.06 percent of total sales, an amount grossly less than the 0.5 to 1.0

[16] Ibid, p. 49.
[17] Ibid, p. 49.
[18] Response to Consumer Advocate Data Request 56.
[19] Response to Consumer Advocate Data Request 68.
[20] Piedmont Petition, p. 5.

percent achieved by other leading gas utilities outlined in Exhibit DED-3. Piedmont's total expenditures on energy efficiency programs average less than 0.15 percent of total distribution revenues: a share that is also far lower than the leading natural gas distribution companies outlined in Exhibit DED-3.

Q. HAVE YOU ESTIMATED THE POTENTIAL LOST MARGINS FROM THE IMPLEMENTATION OF THESE PROGRAMS?

A. Yes. The estimated lost margins resulting from these programs is very small. Using the therm savings[21] provided by the Company, the annual lost revenue over the first three years is estimated to be approximately $20,000 per year, or 0.01 percent of total non-gas distribution revenues.[22] It would clearly be a stretch to suggest that these small commitments to energy efficiency would result in any meaningful negative financial consequences.

Q. HOW SIGNIFICANT HAVE THE COMPANY'S REVENUE LOSSES BEEN FROM CHANGES IN USE PER CUSTOMER?

A. The implied revenue losses from changes in the Company's residential UPC have varied. Exhibit DED-4 provides a table outlining the Company's total residential customers, total residential usage, residential use per customer and an estimate of the base revenue changes associated with annual changes in use per customer. Over the past several years, changes in residential UPC are estimated to have accounted for revenue losses at a level much higher than the potential revenue losses attributable to the promotion of the Company's proposed energy efficiency programs.

[21] The Company only provided therm savings for its High Efficiency Equipment Rebate Program, although data was requested for all programs.

[22] Estimated from response to Consumer Advocate Data Request 68.

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 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. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT THE TRA'S CURRENT REGULATIONS CREATE DISINCENTIVES TO ENERGY EFFICIENCY?

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 Piedmont, and other regulated utilities, to provide cost-effective energy efficiency 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. 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 opportunity to earn a return on and of their investments, these opportunities are not synonymous with an entitlement (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. Importantly, regulatory lag can be an important policy tool in controlling utility costs which ultimately can lead to lower rates.

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

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, 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?

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.[23] 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,

[23] Brennan, Timothy J. "'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. August, 2008.

and former director of the Institute of Public Utilities[24] at the Michigan State University characterized revenue decoupling as a "scholarly abomination."[25]

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, 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 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?

[24] 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.

[25] Brennan, Timothy J. "Decoupling". Presented to the Institute of Public Utilities, Michigan State University, 40th Annual Regulatory Policy Conference. December 10, 2008.

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 reduces 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.

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 recognizes 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.

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 is perceived to align the interests of the Company and its customers is not correct.[26] 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

[26] Piedmont Petition, p 4.

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;

(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.[27]

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

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

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."[28]

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

A. Yes, Exhibit DED-5 shows the recent activity on revenue decoupling for natural gas utilities across the U.S. Currently, there are 18 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, Massachusetts, Nevada, New Jersey, New York, North Carolina, Ohio, Oregon, Utah, Virginia, Washington, Wisconsin and Wyoming. Another six states have enacted legislation that requires decoupling including Connecticut, Massachusetts, Michigan, Minnesota, New York and Wisconsin. Delaware and Nebraska 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."[29] Similarly, the Arizona and Iowa 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

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

[29] 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.

engage in meaningful energy efficiency programs because of concern about their earnings."[30] In 2006, the Nebraska Commission recognized the possibilities of increased rates and risk shifting from decoupling:

> 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.[31]

Q. HAS THE TRA MADE ANY FINDINGS ON DECOUPLING?

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

[30] 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.

[31] 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.

costs. Therefore, I move to deny the Customer Utilization Adjustment.[32]

Chairman Kyle and Director Jones both agreed with the motion made by Commissioner Miller.[33] The concerns raised by the TRA reflect at least one of the same concerns I have about the Company's current proposal.

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 SOME COMMISSIONS TO CHANGE THEIR PRECEDENT?

A. Yes. In 2006, the Connecticut DPUC rejected revenue decoupling for its electric and gas utilities. However, 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, it recently rejected a comparable proposal for Connecticut Natural Gas and noted:

[32] Director Miller's Motion.
[33] Docket No., 05-00258, Tr. October 26, 2006, pp. 6-7, 15.

> 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 guaranteed 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.[34]

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

A. Yes. In Michigan, decoupling proposals were dropped by both SEMCO and Consumers Energy as part of settlement agreements. However, in October 2008, the Governor signed into law allowing natural gas utilities to request a symmetrical revenue decoupling plan as long as they are spending at least 0.5 percent of total revenue on energy efficiency programs.[35] In addition, Minnesota's Next Generation Energy Act requires the Commission to establish criteria for decoupling that mitigates the impact on utilities of the energy savings goals (established in the Act) without adversely affecting ratepayers. It also directs the Commission to allow one or more rate-regulated utilities to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote EE and conservation.

[34] Application of Connecticut Natural Gas Corporation for a Rate Increase. Connecticut Department of Utility Control. Docket No. 08-12-06. June 30, 2009.

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

Q. DO YOU THINK THE ARRA REQUIRES THE ADOPTION OF REVENUE DECOUPLING?

A. No. 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 would be 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.[36]

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING ISSUE 1?

A. I recommend that the TRA reject the Company's proposed MDT since current regulation in Tennessee provides adequate financial incentives for the promotion of cost-effective energy efficiency. The proposal should also be rejected since the Company has not shown that its proposed energy efficiency proposals would create any form of financial harm or disincentives.

[36] 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. ARE THERE ANY ALTERNATIVES TO REVENUE DECOUPLING THAT THE TRA COULD ADOPT SHOULD IT HAVE CONTINUING CONCERNS ON THE ISSUE OF ENERGY EFFICIENCY INCENTIVES?

A. Yes. To the extent the TRA has continuing concerns about energy efficiency incentives, it could easily adopt what is referred to as a lost base revenues mechanism that would allow the Company to recover lost margins from meeting proven energy efficiency targets. I will discuss this alternative proposal in greater detail in a later section of my testimony.

Q. WHAT IF THE TRA WANTED TO ADOPT A MECHANISM THAT WAS MORE "PRO-ACTIVE" IN NATURE?

A. If the TRA wishes to adopt a mechanism that it believes is more pro-active in creating positive incentives for energy efficiency (instead of simply removing a disincentive), then I recommend it adopt a performance-based incentive mechanism that ties potential financial rewards to the achievement of greater-than-average energy efficiency savings. This is discussed in greater detail in section VIII of my testimony. The important conclusion to highlight about either of these alternative recommendations (lost base revenue or incentives) is that they are performance-based in nature, and not simply guaranteed revenue recovery mechanisms. Lost base revenue recovery and incentive mechanisms are tied to the verifiable savings attained by the Company. The higher the level of achieved savings, the greater the revenue recovery or incentives. A performance-based mechanism is more consistent with traditional regulatory approaches as well as the more recent developments in regulatory practice.

V. APPROPRIATE BILLING DETERMINANTS, BENCHMARKS, AND RATEPAYER PROTECTION MECHANISMS SHOULD DECOUPLING BE ACCEPTED (ISSUE 2)

Q HOW HAS THE COMPANY DETERMINED ITS NORMALIZED MARGIN FOR DECOUPLING PURPOSES?

A. The Company has established a monthly normalized margin that is comprised of using normal degree days, a base heating factor, a heat sensitivity factor from the last rate case in order to develop a normalized use per customer factor. This factor is coupled with actual customers to develop a normalized usage amount, which is then multiplied by the allowed margin per therm from the last rate case, to derive a total normalized margin amount. This monthly normalized margin is compared to the actual margin collected in that month to arrive at a margin differential (less a WNA adjustment). This differential is booked to the deferral account for recovery during the collection periods. An illustrative example, for the months of March and April 2009, of the Company's decoupling calculations is shown on Exhibit DED-6.

Q. DO YOU HAVE ANY RECOMMENDATIONS THAT MAY AMELIORATE THIS MISMATCH SHORTCOMING?

A. Yes. The Company should be required to undergo a full rate case if the TRA decides to move forward with revenue decoupling. Over the past five years, revenue neutrality programs have been considered in at least 22 rate case proceedings rather than stand-alone dockets. This is an important distinction since a rate case gives a regulatory commission, as well as other parties, a wide

range of ratemaking tools and policy options to address structural and programmatic changes to offset purported disincentives to energy efficiency, or make a number of appropriate corrections for the regulatory policy shortcomings for revenue decoupling. For instance, a rate case can also be a more useful proceeding to consider revenue decoupling since a broader range of risk-mitigation measures, such as a reduction to a utility's allowed ROE, can also be addressed. I will discuss these issues in greater detail in the next section of my testimony.

Q. IF THE TRA DOES NOT UTILIZE A FULL BASE RATE CASE FOR REVENUE DECOUPLING IMPLEMENTATION, WHAT ARE YOUR RECOMMENDATIONS ON THE APPROPRIATE BILLING DETERMINANTS USED IN CALCULATING THE MARGIN BASELINE?

A. The TRA should use billing determinants (normalized use per customer per HDD) that are based upon the most recently-available usage and weather information (12 months ending September 2009). I have estimated updated the normal degree day estimates, as well as the base load factor and heat sensitivity factor, which have been provided in Exhibit DED-7. Mr. Terry Buckner is sponsoring the actual calculations for the revised billing determinants.

Q. IF THE TRA ACCEPTS THE COMPANY'S REVENUE DECOUPLING PROPOSAL DO YOU HAVE ANY OTHER RECOMMENDED CHANGES TO THE MANNER IN WHICH ACCRUALS ARE CALCULATED?

A Yes. I recommend that the TRA modify the Company's approach to exclude its proposed allowance for increased revenues from customer growth.

Q. CAN YOU EXPLAIN HOW THE COMPANY'S DECOUPLING MECHANISM INCLUDES A REVENUE ALLOWANCE FOR CUSTOMER GROWTH?

A. Yes. The Company's decoupling mechanism is not simply developed to true-up actual revenues to those established in a base or test year. The Company's proposal would also allow them to recover additional revenues for customer growth since the allowed margin in any given month is based upon actual customers and not test year customers from the rate case.

Q. WHY WOULD THESE ADDITIONAL REVENUES BE NECESSARY?

A. Quite often, utilities proposing revenue decoupling will argue that they need to collect additional revenues in their decoupling mechanisms to accommodate the increased cost of serving new customers. This argument, however, presumes that the cost of serving these new customers is above and beyond what is already included in rates. Any request for an allowance for new revenue growth above and beyond what is included in base rates should at least be accompanied by some evidence that the incremental cost of serving new customers is significantly greater than the embedded cost.

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 Consumer Advocate's Data Request 33 asked for information on the cost of serving new customers by customer class. The Company indicated that it does not "currently perform such detailed analysis nor does it maintain

records with the detail necessary to provide the analysis as requested." The Company did provide the amount of investment in distribution plant in comparison to the number of customers added, by customer class. However, this data includes all customer classes. Because the Company is only requesting that the residential class be subject to its proposed MDT, the data supplied for all customer classes is not particularly helpful.

Q. HAVE YOU EXAMINED THE COMPANY'S INCREMENTAL COST INFORMATION?

A Yes. Exhibit DED-8 provides this information and it does show some increase over embedded costs for 2008 and 2009, but these cost increases are (a) for total customers and (b) largely unexplained and require additional documentation and analysis. For instance, in 2008 the Company indicated an embedded customer cost of **Begin Confidential** $3,001 **End Confidential** compared to a new incremental customer cost of **Begin Confidential** $3,268. **End Confidential** For 2009, the Company stated that the cost of adding a new customer is **Begin Confidential** $4,784 **End Confidential**. Yet, as noted earlier, there are no details concerning the type of new customer added, nor is it possible to clearly determine what created the increased costs in these two years. The unaccounted for change in the cost of serving new (total) customers is an additional reason why considering revenue decoupling within the context of a full rate case can be a more productive venue in which to address important program design details and any necessary adjustments.

Q. HOW DO YOU PROPOSE TO CALCULATE THE MONTHLY MARGIN ACCRUALS?

A. If the Company is going to be allowed to change its allowed margins to reflect new customers, then the overall normalized use per customer per HDD needs to be updated as well. This can be done by re-estimating the normalized HDDs, the base load therms per month, and the heat sensitivity factor. These monthly updates have been provided on Exhibit DED-7, for the retrospective period October 2008 to September 2009.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS ASSUMING THE TRA APPROVES THE COMPANY'S REVENUE DECOUPLING PROPOSAL?

A. Yes, I have two additional recommendations. The first relates to the term of the decoupling program and the second relates to ratepayer protection mechanisms.

Q. LET'S TURN TO THE FIRST RECOMMENDATION. IS THE COMPANY PROPOSING DECOUPLING ON A PILOT OR PERMANENT BASIS?

A. Unlike most revenue decoupling proposals around the country, the Company's proposal has not been specifically offered as a pilot program. Most other electric and gas utilities have mechanisms approved on a pilot or a fixed review period basis. For instance, of the 36 electric and natural gas utilities currently under some form of revenue decoupling, more than 20 (over half) were originally proposed and approved on a pilot or fixed periodic-review basis. The Company's petition, however, fails to identify a specific term for its revenue decoupling proposal. I recommend that, should the Commission accept the

Company's proposal, it do so on no more than a three-year basis. A decoupling review process should be conducted at the end of this the fixed year term, and I will discuss my recommendations on this review process within the context of my ratepayer protection mechanism proposals.

Q. LET'S TURN TO YOUR RECOMMENDATIONS ON RATEPAYER PROTECTION MECHANISMS. WHAT ROLE DO RATEPAYER PROTECTION PROVISIONS PLAY IN THE COMPANY'S REVENUE DECOUPLING PROPOSAL?

A. The Company's proposal excludes a large number of ratepayer protection mechanism or circuit break used by other state regulators to control run-away or unanticipated consequences of this alternative form of regulation.

Q. HAVE ANY OTHER STATES ADOPTED CONSUMER PROTECTION PROVISIONS AS PART OF THEIR DECOUPLING MECHANISMS?

A. Yes. As shown in Exhibit DED-9, several states have adopted various types of consumer protection provisions as part of their revenue decoupling programs. In fact, these protections appear to be more commonplace, with broader conditions, as more states move forward with revenue decoupling. Some of the states that have adopted varying degrees of consumer protection mechanisms include Oregon, Washington, Utah, and Colorado, to name a few.

Q. WHAT TYPES OF PROTECTIONS HAVE STATES ADOPTED TO PROTECT CUSTOMERS FROM POTENTIALLY HARMFUL ASPECTS OF REVENUE DECOUPLING?

A. Various states have used one, or a combination of the following ratepayer protections in the development of their respective revenue decoupling mechanisms:

- **Recovery Structures:** This type of protection typically limits the range of revenue recovery for a utility under decoupling. One example of this is Colorado's approach that only allows revenue recovery in instances where UPC falls by more than 50 percent of the five-year average decrease.
- **Recovery Limitations:** This type of protection restricts the amount of revenue that can be collected in any period. Examples include Oregon's original approach that limited revenue recovery to only 90 percent of the difference between actual and allowed margins, and Indiana's provisions that restrict revenue recovery to only 85 percent of the difference between allowed and actual margins.
- **Caps on Accruals:** This approach is common among approved decoupling mechanisms and caps the amount of overall accrual to some pre-defined level. One example would be Utah's limitation on recovery balances of one percent of total revenues or Wisconsin's 100 basis point limitation.
- **DSM Targets or Goals:** Many programs either require DSM targets or goals to be a companion of the adoption of revenue decoupling. The purpose is to ensure that the energy efficiency benefits are offered to customers in return for the cost of decoupling.

- **Annual Filings and Periodic Reviews:** Many programs require utilities to file information on balances and true ups periodically and many limit the adoption of revenue decoupling programs to a fixed period for a review on potential unanticipated consequences.

Q. DO YOU THINK IT WOULD BE APPROPRIATE TO ADOPT ONE OR SEVERAL OF THESE PROTECTIONS SHOULD THE TRA APPROVE PIEDMONT'S DECOUPLING MECHANISM?

A. Yes. I recommend that the TRA adopt a mechanism similar to that adopted in Colorado that restricts overall recoveries to only those amounts greater than the historic average reductions in use per customer. The Colorado Commission adopted this protection for the following reasons:

> We find that the entire risk associated with declining per customer use should not be assigned entirely to Public Service's residential customers. We expect that Public Service is aware of this decline in use per customer, and should be undertaking its own internal cost reduction, becoming more efficient through process re-designs and seeking more productive uses of its labor and capital resources. Becoming more efficient in the face of declining demand for an enterprise's product is rational economic behavior for a firm.[37]

Q. HOW WOULD THIS TYPE OF MECHANISM WORK?

A. An illustration has been provided in Schedule DED-10 and uses 2009 as the "base year" for decoupling purposes. The threshold percent change is set at 0.9 percent and is based upon the average annual change in the Company's weather-adjusted UPC over the past 5 years. The example assumes that in the

[37] Re: The investigation and suspension of tariff sheets filed by Public Service Company of Colorado for Advice Letter No. 690-Gas, Decision No. C07-0568, Docket No. 06S-656G, Colorado Public Utilities Commission, June 18, 2007, Adopted; July 3, 2007 Mailed.

first two years of the decoupling program, the Company experiences an actual UPC reduction that is lower than the threshold amount. In this situation, there would be no revenue recovery adjustment. In the third year, however, the change in Piedmont's actual UPC is assumed to change in such a manner that the threshold percent is exceeded, thereby creating an opportunity for the Company to recover lost revenues in excess of the threshold amount. The net percent allowed to be recovered is provided in the last column of Schedule DED-10.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes, if the TRA does not accept my recommendation for a recovery threshold amount, then I would recommend that it adopt a total revenue recovery balances cap for the Company's decoupling program. The cap should be set at a level no higher than 2.0 percent of total weather-adjusted base revenues.

Q. IF THE TRA ADOPTS REVENUE DECOUPLING, DO YOU HAVE ANY OTHER CONSUMER PROTECTION RECOMMENDATIONS?

A. Yes. If the TRA approves Piedmont's proposal, 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.

Q. WOULD YOU PLEASE SUMMARIZE ALL OF YOUR ALTERNATIVE RECOMMENDATIONS REGARDING THE COMPANY'S DECOUPLING MECHANISM?

A. Yes, if the TRA decides to move forward with revenue decoupling without a full rate case, it should significantly modify the proposal offered by the Company as follows:

- Utilize the billing determinants estimated with more contemporaneous load and weather information that is provided in Exhibit DED-7.
- 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 only those amounts in excess of the recent changes in the Company's Use Per Customer ("UPC"). Revenue recovery

should only occur if UPC changes by more than 0.9 percent per year and then it should be restricted to the difference between the actual UPC percent change and a 0.9 percent threshold level.

- 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 filings with the Authority which are in the same format as provided in North Carolina. In addition, the Company should make annual filings 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.

- The Company should be required to develop performance metrics and report these metrics to the TRA annually.
- To the extent there is a contested rate case or earnings review within the three year review period, the TRA should also examine the merits, and any potential modifications, of the MDT in that proceeding.

VI. EARNINGS, RATE CASE EVALUATION, AND REVENUE DECOUPLING (ISSUE 3)

Q. WHY WOULD A FULL RATE CASE BE MORE APPROPRIATE VENUE FOR CONSIDERING A REVENUE DECOUPLING PROPOSAL?

A. A full rate case would be more appropriate since it will review, calibrate, and align the Company's costs and revenues at one time. This would have the advantage of setting the "cast-off rates" as accurately as possible to minimize potential future distortions and unanticipated outcomes.

Q. HAVE YOU EXAMINED THE COMPANY'S FINANCIAL STATISTICS SINCE ITS LAST RATE CASE?

A. Yes. Exhibit DED-11 presents the Company's financial statistics from 2002 through 2008. As depicted on this exhibit, Piedmont's achieved return on rate base increased from 7.30 percent in 2002 (the test year in the last rate case)

to 7.75 percent in 2003 and again to 9.68 percent in 2004, the year the last rate case became effective.[38] Since 2004, the Company's return on rate base declined to 8.56 percent in 2005, to 7.53 percent in 2006, and to 7.46 percent in 2007. However, in 2008, the Company's return on rate base increased to 9.86 percent.

Q. HOW DOES THE COMPANY'S 2008 ACHIEVED RETURN COMPARE TO THE LAST AUTHORIZED RATE OF RETURN?

A. In the Company's last rate case, the TRA authorized a return on rate base of 8.42 percent,[39] an amount lower than the 2008 achieved return of 9.86 percent, indicating some possibility of an over-earnings situation. If the TRA is inclined to adopt a revenue decoupling mechanism, it should not do so until the Company's actual earnings have been explored in further detail (through a full rate case) to ensure that decoupling does not exacerbate what may already be an over-earnings situation. Instead, rates should be realigned to ensure that customers are paying fair, just, and reasonable rates before decoupling is initiated.

Q. ARE THERE ANY OTHER ADVANTAGES OF UTILIZING A FULL RATE CASE FOR THE ADOPTION OF REVENUE DECOUPLING?

A. Yes. A full rate case would be a more appropriate proceeding to consider the risk-shifting nature of revenue decoupling and any potential adjustments to

[38] Rates in Docket No. 03-00313 were effective November 1, 2005, by stipulation.

[39] In Re: Application of Nashville Gas Company, a division of Piedmont Natural Gas Company, Inc. for an adjustment of its rates and charges, the approval of revised tariffs and the approval of revised service regulations. Tennessee Regulatory Authority, Docket No. 03-00313. Order approving rate increase and rate design and approving rates filed by Nashville Gas Company, July 15, 2004, p. 6.

the Company's allowed ROE. Dr. Klein is discussing issues associated with risk and ROE proposals in greater detail in his testimony.

Q. HAVE OTHER STATES PREFERRED TO ADOPT REVENUE DECOUPLING WITHIN THE CONTEXT OF A FULL RATE CASE?

A. Yes, of the 33 utilities that have approved revenue decoupling mechanisms, 22 were approved as part of a full rate case as opposed to a stand-alone, regulatory investigation.

Q. WHAT ARE YOUR RECOMMENDATIONS ON THE ISSUES OF EARNINGS REVIEWS, RATE CASES, AND REVENUE DECOUPLING?

A. I recommend that if the TRA decides to move forward with revenue decoupling, it direct the Company to file a formal rate case. The Order directing Piedmont to file a rate case should also require the Company to file the following information:

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

- A tariff showing the manner in which the Company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;
- An analysis of how changes in risk resulting from the adoption of revenue decoupling have been taken into consideration in the determination of its proposed Return on Equity ("ROE");
- A full analysis of the potential and cost-effective energy efficiency opportunities in its service territory;
- A full energy efficiency plan that includes cost effectiveness findings for each major energy efficiency measure/program being proposed; and
- A proposed energy efficiency/revenue decoupling review process including goals, targets, and benchmarks.

VII. EFFECT OF DECOUPLING ON BUSINESS RISK (ISSUE 4)

Q. WOULD YOU PLEASE DISCUSS THE HEARING OFFICER'S FOURTH ISSUE?

A. Yes. The fourth issue identified by the Hearing Officer concerned the relationship of decoupling and business risks and was framed as:

> Does the implementation of a decoupling mechanism lower the business risk for Piedmont, thereby justifying an adjustment to its rate of return? If so, what method or evaluation tools should be utilized to quantify an appropriate adjustment to the rate of return?

Q. WHAT IS PIEDMONT'S POSITION ON THIS ISSUE?

A. The Company does not believe that a decoupling mechanism will affect the business risk it faces or the overall risk to investors. In response to a data request from the TRA, the Company indicated:

> Piedmont has operated with a margin decoupling mechanism in North Carolina since 2005 (and with a rate stabilization mechanism in South Carolina since 2005). We are aware that equity analysts have since noted in their analyses of Piedmont that it is a positive regulatory mechanism because it allows the Company to exactly recover the per customer margin approved in its rate case. However, we have never seen a quantitative risk value assigned or associated with having this mechanism. In light of the magnitude of the main factors influencing the risk perceived by investors, a decoupling mechanism for our residential market in Tennessee will not impact the Company's overall risk to investors.[40]

Q. DID THE COMPANY PRODUCE ANY EVIDENCE THAT A DECOUPLING MECHANISM WOULD NOT IMPACT ITS FINANCIAL RISK?

A. No, it did not. In response to the Consumer Advocate's Data Request 48, the Company was unable to provide any peer-reviewed articles, research, analysis, or any other studies supporting its contention that a decoupling mechanism would not impact its overall risk.

Q. HOW DOES DECOUPLING SHIFT RISK AWAY FROM UTILITIES AND TOWARDS RATEPAYERS?

A. Risk is shifted to ratepayers through the revenue decoupling true-up mechanism which provides utilities with a guaranteed revenue per customer ("RPC") amount. Current regulatory approaches only give utilities an opportunity to earn typical revenues, but do not guarantee that recovery. Under the Company's revenue decoupling proposal, if revenues fall short of the target

[40] Response to TRA Data Request, 1-8.

amount, customers are expected to make up the difference. The opposite would occur if sales are larger than the target amount.

Q. HOW MUCH OF THE COMPANY'S REVENUE REQUIREMENT WOULD BE SUBJECTED TO THE MARGIN DECOUPLING TRACKER IF IT IS ACCEPTED BY THE AUTHORITY?

A. In the Company's 2003 Rate Case, Docket No. 03-00313, the approved revenue margin for residential customers was $51,021,291[41] which comprises approximately 41 percent of total residential revenues, and 23 percent of total Company revenues approved in that proceeding.[42] The Company is proposing that its tracker be applied only to residential customers. However, for the year ending 2008, Commercial and Industrial and Special Contract customers contributed some 51 percent of Piedmont's total revenue, a significant increase over the last rate case where these customers only accounted for 43 percent of Piedmont's total revenue.

Q. WHAT TYPES OF FACTORS IMPACT REVENUE RECOVERY UNDER TRADITIONAL REGULATORY APPROACHES?

A. As I noted earlier, a number of factors can influence sales including weather, economic conditions, gas commodity prices, and other unanticipated events that impact usage. Under traditional regulation, these potential risks are borne by the utility, not by ratepayers. Under revenue decoupling these risks are all shifted to ratepayers.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

[41] Response to TRA Data Request 2-4.
[42] Ibid., Attachment 1.

A. 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. 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.[43]

Q. COULD THE COMPANY'S DECOUPLING PROPOSAL CREATE THE SAME KINDS OF PROBLEMS AS THOSE EXPERIENCED IN MAINE?

A. Yes, particularly in its current form that excludes any type of ratepayer protection mechanism. The Company's decoupling proposal makes no allowances or adjustments for changes in economic activity, positively or negatively. If the economy underperforms, ratepayers will be required to make the Company whole, even though revenue losses associated with this downturn had nothing to do with the implementation of energy efficiency programs.

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

[43] 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.

inconsistent with the fair, just, and reasonable standards of traditional utility regulation.

Q. HAVE ANY OTHER REGULATORY COMMISSIONS RECOGNIZED THE RISK SHIFTING NATURE OF REVENUE DECOUPLING?

A. Yes. In 2006, the Connecticut Department of Public Utility Control ("DPUC") ruled 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. **In general, the more complete the decoupling, the more business risks are shifted from the energy DCs to the ratepayers**.[44]

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

A. Yes. Recently, in Connecticut Natural Gas' proposal for decoupling the DPUC found that:

> 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

[44]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*.

> 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.[45]

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 . . .[46]

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

[46] 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

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.[47]

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.[48]

Q. HAVE ADJUSTMENTS TO A UTILITY'S ALLOWED RATE OF RETURN FROM REVENUE NEUTRALITY PROPOSALS BEEN RECOGNIZED IN OTHER UTILITY PROCEEDINGS?

A. Yes. Exhibit DED-12 shows that a number of states, as well as the Federal Energy Regulatory Commission ("FERC"), have made for adjustments to

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Corporation Devoted to its Operations Throughout the State of Arizona, Docket No. G-01551A-04-0876; Decision No. 68487, February 23, 2006.

[47] 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.

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

the allowed rate of return in recognition of the fact that revenue neutrality programs change the risk profiles of regulated utilities. Some of these adjustments have actually been proposed by utilities, and in a number of cases, these adjustments have been adopted. Adjustments range from 6.5 to 50 basis points on a utility's allowed ROE. In Delaware, Delmarva Light and Power recommended an ROE reduction of 25 basis points as a risk correction for its proposed revenue decoupling mechanism. The proceeding settled and revenue neutrality proposals were withdrawn for later consideration in a generic docket.[49] Similarly, Chattanooga Gas in Tennessee recommended a 50 point basis reduction if both its proposed revenue decoupling mechanism and infrastructure replacement rider were approved.[50] Again, the case was settled and the proposal for decoupling was withdrawn.[51] In Vermont, Green Mountain Power agreed to a 50 basis point reduction and noted that its Alternative Regulation Plan "has the effect of shifting risk associated with varying power costs to ratepayers; in recognition of this risk shift, the Plan provides a lower return on equity (ROE)."[52]

Q. DO YOU THINK THE FINANCIAL COMMUNITY RECOGNIZES THE RISK SHIFTING NATURE OF REVENUE NEUTRALITY MECHANISMS?

[49] In the matter of the application of Delmarva Power & Light Company, for a change in natural gas base rates (filed August 31, 2006), PSC Docket No. 06-284, Order No. 7152, March 20, 2007.

[50] Prepared Direct Testimony of Dr. Roger A. Morin. In Re: Chattanooga Gas Company, Docket No. 06-00175.

[51] Petition of Chattanooga Gas Company for approval of adjustment of its rates and charges, comprehensive rate design proposal and revised tariff, Docket No. 06-00175, May 8, 2007.

[52] Petition of Green Mountain Power Corporation for approval of an alternative-regulation plan, Docket No. 7175; Docket No. 7176, Vermont Public Service Board, December 22, 2006, Order Entered.

A. Yes, as well as a number of other favored, risk-shifting programs that can, depending upon the state, include the adoption of gas recovery clauses, weather normalization clauses, shorter weather normalization periods, and pass-through recovery of LAUF (lost and unaccounted for) gas (for gas utilities), and uncollectibles expense. Revenue neutrality, in the form of revenue decoupling or SFV ("Straight Fixed Variable") rate designs (for gas utilities), however, appears to be the most popular regulatory mechanism with many financial analysts (with the exception of the few gas utilities that do not have gas cost recovery mechanisms). Analysts see revenue neutrality mechanisms as being beneficial to shareholders by reducing overall risk.

Q. DO YOU HAVE ANY EXAMPLES?

A. Yes, Moody's Investor Service ("Moody's") in a June 2005 Special Comment on natural gas utilities noted:

> . . . Moody's believes that having utility rate designs that compensate the gas LDC for variations in conservation as with variations in weather, would serve to stabilize the utility's credit metrics and credit ratings.[53]

Further, Moody's indicated that revenue decoupling can impact the business risk categorization under which utilities are judged. This categorization, based upon business risk profiles, includes a measure for utilities that face supply and volumetric risk. Those with high risk are in the higher categories (highest risk category is 10), while those utilities that face lower risks by having adjustment clauses, are moved to lower levels. NW Natural, a gas distribution utility in Oregon that has both a gas cost recovery ("GCR") and decoupling mechanism,

[53] Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, Moody's Investors Services, June, 2005, p. 8.

was able to lower its rank to 1, the lowest level category. Moody's recently reiterated the strong benefits revenue decoupling would provide in maintaining shareholder value. Such a mechanism will maintain strong credit metrics and improve credit ratings relative to utilities that do not have such mechanisms since revenue decoupling eliminates shareholder exposure to risk and volatility from price and climate changes.[54]

Q. HAVE ANY UTILITY EXECUTIVES RECOGNIZED THE FINANCIAL BENEFITS OF REVENUE DECOUPLING?

A. According to a recent review of the NW Natural decoupling program, the consultants for the Oregon Public Service Commission found that:

> [NW Natural] CFO David Anderson believes that DMN [Distribution Margin Normalization] and WARM [Weather Adjusted Rate Mechanism] were contributing factors to NW Natural obtaining the best rating in the Standard & Poor's (S&P) business risk profile (scoring a 1 on a scale of 1 to 10). Similarly, he believes that DMN and WARM contributed to the upgrade in NW Natural's S&P bond rating from A to A+. An improved risk profile has several beneficial effects. It allows NW Natural to maintain smaller lines of credit, reduce the share of equity in its capital structure, and maintain a lower coverage ratio.[55]

Q. CAN ADOPTING DECOUPLING WITHOUT A RISK-SHIFTING ADJUSTMENT RESULT IN FAIR, JUST, AND REASONABLE RATES?

A. No. The Company's decoupling proposal shifts a significant amount of risk to ratepayers. These risks include potential changes in price, the economy, and other factors like greater economy-wide energy efficiency. However, under the

[54] Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings, Moody's Investor Services, June 2006.

[55] Christensen Associates Energy Consulting, LLC. A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural Gas. March 31, 2005, p. 72.

Company's current proposal, there is no corresponding offset in rates to compensate ratepayers for this shift. Thus, approving revenue decoupling, while failing to recognize the risk-shifting inherent in this mechanism, results in rates that by definition are not fair, just, and reasonable and allows the utility to claw into the very monopoly profits that regulation is intended to control.

Q. DO YOU HAVE A SPECIFIC ROE RECOMMENDATION IN THIS PROCEEDING?

A. No, this issue is being addressed by Dr. Klein. The purpose of my testimony is to address the policy issues related to risk shifting resulting from revenue decoupling and the range of regulatory options used by utility commissions in addressing the risk shifting properties of revenue decoupling.

Q. ARE ROE ADJUSTMENTS THE ONLY MECHANISMS BY WHICH REGULATORY COMMISSIONS CAN ADJUST FOR RISK?

A No. Several regulatory commissions have found alternative ways to adjust for the risk-shifting properties of various revenue decoupling proposals. These alternative methods can include: (1) putting a band around revenue recoveries; (2) caps on revenue recoveries; (3) a requirement that utilities pay for the cost of DSM programs "below-the-line;" (4) tying revenue decoupling recoveries to upstream capacity savings; and (5) performance-conditions on recoveries. Many of these methods can be adopted in conjunction with, or in lieu of an ROE or other rate of return adjustment.

VIII. ENERGY EFFICIENCY PROGRAM METRICS (ISSUE 5)

Q. WHAT IS ISSUE 5 SET FORTH IN THE PROCEDURAL ORDER?

A. The Prehearing Officer defined Issue 5 as:

> Should Piedmont be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs?

Q. BEFORE MAKING A RECOMMENDATION CONCERNING ISSUE 5, WOULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED ENERGY EFFICIENCY PROGRAMS?

A. The Company has proposed three energy efficiency programs ("EEP"): a Customer Education Program; a Residential Low-Income Energy Efficiency Program; and a High Efficiency Equipment Rebate Program.

Q. HOW WILL THE CUSTOMER EDUCATION PROGRAM WORK?

A. The Customer Education Program will focus on customer education through efficiency and conservation messages communicated through bill inserts, print advertisements and radio and/or other media. In addition, the Company will encourage customers to take advantage of federal tax credits available for the installation of high efficiency equipment. Piedmont plans to spend approximately $100,000 on this program.[56]

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S LOW-INCOME ASSISTANCE PROGRAM?

A. The Residential Low-Income Energy Efficiency Program will provide assistance with weatherization and energy efficiency measures such as insulation, sealing and insulating of ducts, and installation of programmable thermostats to low income residential customers. The program is patterned after

[56] Piedmont Petition, Exhibit B, p. 1.

the Federal Weatherization Assistance program and the Company's low-income program in North Carolina. Customers will be considered "low income" if their household income is no more than 200 percent of the 2009 federal poverty guidelines in the Federal Weatherization Assistance Program. The Company estimates between 40 and 55 customers will participate in the program with an average cost of $3,000 per household.[57]

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S HIGH EFFICIENCY EQUIPMENT REBATE PROGRAM?

A. The High Efficiency Equipment Rebate Program will provide rebates to residential customers purchasing high efficiency natural gas water and space heating equipment. Piedmont has adopted the minimum required efficiency standards used by Energy Star for this program. The rebate schedule is summarized in Exhibit DED-13.

Q. HAS THE COMPANY IDENTIFIED THE COSTS OF THESE PROPOSED PROGRAMS?

A Yes. Piedmont estimates the total annual cost of this program to be $250,000 of which $190,000 will be spent on rebates, $20,000 on program development and administration, $20,000 on communications, and $20,000 on evaluation, measurement and verification. The Company has provided no explanation or supporting documentation for how these cost estimates were developed. When asked to provide supporting documentation for these

[57] Piedmont Petition, Ex. B., p. 2.

estimates, like budgets and workpapers, the Company responded that it had no responsive documents.[58]

Q. DOES THE COMPANY HAVE ANY EXTENSIVE EXPERIENCE WITH ANY EQUIPMENT REBATE PROGRAMS IN ITS OTHER STATES?

A. The Company does not have a rebate program for High Efficiency Equipment in either North or South Carolina but does have a rebate program for the purchase and installation of weatherization products for residential customers in North Carolina. Unfortunately, the Company discontinued this program in December 2008 due to the "relative lack of interest from customers in the pilot areas".[59] The Company has provided no documentable market studies, analyses, or empirical analyses that would suggest the same outcome would not arise in Tennessee.

Q. HOW DID THE COMPANY DETERMINE THE COST EFFECTIVENESS OF ITS PROPOSED PROGRAMS?

A. The Company indicated that it followed the protocols of the California Standard Practice Manual in determining the cost effectiveness of the High Efficiency Equipment Rebate Program.[60] The Company apparently used the services of The CAMDUS Group, Inc. to perform its cost/benefit analysis.[61] The program's cost effectiveness results concentrated on only two tests: the Total Resource Cost ("TRC") test and the Utility Cost ("UC") test. According to the

[58] Response to Consumer Advocate Data Request 65.
[59] Conservation Effectiveness Report of Piedmont Natural Gas Company, Inc. in Docket No. G-9, Sub 499.
[60] Piedmont Petition, p. 5.
[61] Response to Consumer Advocate Data Request 66.

Company, the High Efficiency Equipment Rebate program has a TRC score of 1.16 and UC test score of 1.86.[62]

Q. ARE YOU FAMILIAR WITH THE CALIFORNIA STANDARD PRACTICE MANUAL?

A. Yes. The *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* defines a set of cost-effectiveness tests, and their respective derivations, for utility-sponsored conservation (energy efficiency) and load management programs. This manual was first published in 1983 as the *Standard Practice for Cost-Benefit Analyses of Conservation and Load Management Programs*. The manual was updated and revised in 1987-1988, in 2001, and in July 2002.

Q. HOW IS THIS MANUAL USED IN EVALUATING ENERGY EFFICIENCY PROGRAMS?

A. The manual contains cost-benefit and cost-effectiveness calculations to evaluate energy efficiency programs from four viewpoints: that of the customer (Participant Test); the ratepayer (Ratepayer Impact Measure Test, or "RIM" test), the utility (the Utility Cost Test),[63] and the customer and utility combined (Total Resource Cost Test or "TRC"). A fifth test, the Societal Test, is a variant of the TRC and considers the change in costs to society as whole and can include environmental externalities costs.

[62] Piedmont Petition, Ex. B., p. 6.

[63] This test can also be referenced as the Program Administrator Cost Test, or "PAC" test.

Q. DID THE COMPANY PROVIDE THE ESTIMATED RESULTS FROM ALL OF THESE COST-EFFECTIVENESS TESTS IN THE EXAMINATION OF ITS PROGRAMS?

A. No, the Company focused exclusively on the TRC and Program Administrator test. Piedmont, for instance, completely neglected to test its proposed program against the Participant Test and many others. Examining program results from the Participant Test would have isolated the quantifiable costs and benefits of the program to the customers it hopes to enroll in the program.

Q. DID THE COMPANY CONDUCT A RIM COST EFFECTIVENESS TEST?

A. No, it did not. The RIM Test is unique since its results are dependent upon the shift in lost revenue (to nonparticipating customers) resulting from an energy efficiency program. The results of this test are primarily reported as the lifecycle revenue impact of the program per unit of energy, that is, the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) or the net present value ("NPV") of the program.[64] This test is particularly important in understanding the "lost revenue" impacts associated with the Company's proposals. Measures that fail the RIM test are those that tend to have significant lost revenues, and as a result, create overall rate impacts by driving up the rates of other ratepayers (i.e., program non-participants) over the longer run.

Q. DID THE COMPANY PROVIDE ITS UNDERLYING CALCULATIONS OF THESE TESTS?

[64] Ibid. p. 13.

A No. The Company has refused to provide the underlying calculations which support the results of the two tests that it reported. In response to the Consumer Advocate's Data Request 66, the Company would not provide the underlying workpapers supporting the only two tests that it performed in electronic spreadsheet format. The Company claimed that the calculations and information included in this analysis were confidential and instead produced the documents in pdf format which does not show the formulas or algorithms used to derive the results. Its failure to produce this information, claimed to be propriety, delays and frustrates the regulatory process.

Q. HAS IT BEEN YOUR PROFESSIONAL EXPERIENCE THAT SUCH ANALYSES ARE CONFIDENTIAL IN NATURE?

A. Typically no. Cost effectiveness analysis are based upon known formulas developed in the California Procedures Manual discussed earlier and are not confidential. These formulas, in turn, should utilize various different "drivers" (variables or inputs) such as measure lives, appliance costs, appliance savings rates, free rider assumptions, expected prices, avoided costs, among other inputs, that, while cumbersome to collect, examine, and document, are not confidential in nature, particularly if they are developed from analyses associated with the Company's service territory. There is no way that information of this nature can be used to create competitive harm to the Company, nor its contractors, and to claim otherwise simply deprives the Consumer Advocate and other stakeholders of the opportunity to review the reasonableness of the Company's analysis and underlying assumptions.

Q. DID THE COMPANY PROVIDE ANY SENSITIVITY ANALYSES?

A. No. The Company presented no evidence that it performed any sensitivity analyses in examining the range of cost effectiveness for its programs, or alternative programs that could have been included into a broader energy efficiency portfolio. The Company also did not attempt to optimize program design by testing the sensitivity of different rebate/participation levels.

Q. DID ANY OF THE COMPANY'S COST EFFECTIVENESS TESTS INCLUDE ADJUSTMENTS FOR "FREE RIDERS" OR "KICKBACKS" EFFECTS?

A. No. It is not uncommon for energy efficiency cost effectiveness analyses to adjust overall estimate savings for the effects that "free riders" and "kickbacks" effects have on program effectiveness. Free riders are typically defined as those customers that participate in a utility-sponsored energy efficiency program, and collect refunds (incentives), but would have installed the energy efficiency measure on their own without the utility support (incentive). Kickback effects can be defined as increases in usage that can arise because an appliance has been made more efficient. An example may include a customer that turns his heating thermostat up to a higher level after installing an energy efficient heater in order to attain greater satisfaction without incurring any significant bill impacts. Neither impact appears to have been considered by the Company in reviewing their workpapers or their responses to discovery.[65]

[65] Response to Consumer Advocate Data Request 66(d).

Q. WHAT TESTS DID THE COMPANY EMPLOY TO MEASURE THE COST EFFECTIVENESS OF THE CUSTOMER EDUCATION AND RESIDENTIAL LOW-INCOME ENERGY EFFICIENCY PROGRAMS?

A. The Company does not discuss any tests that it has used to measure the cost effectiveness of these programs. However, customer education programs (also called "market transformation") tends to not lend itself to any of the tests in the Standard Practice Manual.[66]

Q. WHAT ABOUT THE COST EFFECTIVENESS OF THE LOW-INCOME SUPPORT PROGRAM?

A The Company did not perform any cost effectiveness tests of the Residential Low-Income Energy Efficiency Program despite the fact that the weatherization and energy efficiency measures installed under this program can be estimated. For instance, the Company states it has patterned this program after the Federal Weatherization Assistance Program ("WAP") and its own low-income program in North Carolina yet it failed to utilize this experience in developing Tennessee-specific cost effectiveness analyses.

Q. WHAT OTHER FLAWS DID YOU FIND IN THE COMPANY'S ENERGY EFFICIENCY PROGRAMS?

A. While the Company did provide the projected number of participants for the low-income program in its filing, it provided no explanation or documentation on how it arrived at the estimated participation rate of 40 to 55 households per year. Further, the Company failed to provide any explanation or documentation

[66] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, July 2002, p. 5.

on how this participation rate for the low-income rate may change over time. The Company indicated in discovery that it anticipated an average participation rate of 627 households in its High Efficiency Rebate program.[67] No supporting documentation was provided on how those participation rates were developed. Regardless, this participation rate, which represents 0.43 percent of the Company's total residential customers seems hardly significant enough to justify its proposal to dramatically change the way it prices its distribution services to the remaining 145,642 residential non-participating customers.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE COMPANY'S LOW-INCOME PROGRAM?

A. Yes. The program provides no estimates of the energy savings that may be achieved by any of these programs. When asked to forecast average residential usage for the coming three years the Company referenced its programs in North Carolina, and the "kick-start" that the proposed $350,000 in initial expenditures would give the energy efficiency programs in Tennessee, and concluded:

> We anticipate a decline in the annual normalized gas usage for the customers impacted by the programs. This level of overall program spending would not likely be the cause for any significant erosion in the Company's total normalized annual residential usage per customer over the next three years, due to the size of our residential customer base in Tennessee (150,000 customers). Nevertheless, combining the energy efficiency and conservation programs with the utilization of a decoupling mechanism aligns the Company with customer conservation interests and allows the Company to focus on the best energy solution for the customer. Taking all these factors together, including approval of this petition,

[67] Response to Consumer Advocate Data Request 69.

> we expect the normalized average annual residential gas usage per customer to begin trending below 74 DTs.[68]

Q. DID THE COMPANY DEVELOP ANY ESTIMATES OF THE USAGE REDUCTIONS THAT WOULD RESULT FROM ITS PROPOSED ENERGY EFFICIENCY PROGRAMS?

A. No. Piedmont did not quantify the projected decrease in usage attributable to each of its proposed programs individually. However, it did show some gas savings for its High Efficiency Rebate Program in the confidential workpapers of CADMUS.[69]

Q. HOW DOES PIEDMONT PROPOSE TO EVALUATE THE SUCCESS OF ITS PROPOSED ENERGY EFFICIENCY PROGRAMS?

A. The Company has not identified how it will measure the success of its energy efficiency programs. The Consumer Advocate's Data Request 70 asked the Company to provide documents which set forth the "methods, criteria, and techniques it would utilize to measure the success of these programs." The Company responded that "it had no such documents." This position is reinforced by the Company's failure to provide any criteria that it will follow in deciding whether to continue or terminate each of its programs. In its discussion of the High Efficiency Equipment Rebate Program, the Company noted:

> Piedmont may, at its discretion, lower the rebate amounts offered for each category depending upon the extent of customer participation, timing of implementation, and available funding. The flexibility to adjust incentive levels will allow Piedmont to better maximize the results of the program to promote conservation.[70]

[68] Response to TRA Data Request 4, July 30, 2009.
[69] Response to TRA Data Request 1-2.
[70] Piedmont Petition, Ex. B., p. 4.

Q. DO YOU AGREE WITH THE COMPANY'S REBATE APPROACH?

A. No. A preferable approach would be to define a benchmark for customer participation, and examine the sensitivity of the potential participation rates given incremental increases and decreases in incentive (rebate) levels. For instance, if the first year participation rates in the program are lower than forecast, rebate levels could be increased to stimulate greater participation. Alternatively, if the first year program surpasses expectations by a significant level, it could be a sign that the program is over-incented and that rebate levels need to be reduced. Unfortunately, the Company has not offered any specific, measurable energy efficiency goals or benchmarks that can be utilized to judge the benefits and effectiveness of the proposed programs or how those incentives may be changed on a going forward basis. Further, leaving incentive and rebate levels solely in the hands of the Company, without any input from the TRA, the Consumer Advocate, or other stakeholder groups, is not entirely consistent with best DSM program design and implementation practices in other states.

Q. WHY ARE PERFORMANCE STANDARDS IMPORTANT?

A. Performance standards are an important part of any program, especially those associated with energy efficiency. Defining goals and metrics that measure the successes or shortcomings of reaching those goals, helps explain program success and can provide important diagnostic information in correcting problems that may arise during program implementation and refining the programs.

Q. DO YOU THINK PERFORMANCE STANDARDS ARE A BETTER MEANS OF ALIGNING INCENTIVES FOR THE PROMOTION OF ENERGY EFFICIENCY?

A. They can be if appropriately defined. If revenue decoupling genuinely makes a utility indifferent to sales increases, then the reciprocal is also true: it will also make a utility indifferent to sales decreases that may or may not be attained through energy efficiency programs. Tying an explicit incentive to the promotion of energy efficiency goals gives a regulated utility a financial stake in maximizing efficiency opportunities for its customers. Under such a mechanism, the higher the savings, the higher the potential rewards to the utility. Likewise, the lower the savings, the stiffer the penalties for poor performance.

Q WHAT PROGRAM EVALUATIONS SHOULD BE CONDUCTED?

A. Areas of program performance that should be evaluated include comparisons of estimated to actual implementation costs, estimated to actual energy savings, and estimated to actual participation rates, as well as measures developed to specifically assess program effectiveness relative to the Company's broader scale of operations. Some examples of the latter include energy savings as a percent of retail sales, total program cost per therm of energy savings, and savings as a share of prior-forecasted sales growth.

Q. DO THE COMPANY'S CURRENT PROPOSALS INCLUDE ANY ACCOUNTABILITY MEASURES IN MEETING ITS ESTIMATED PARTICIPATION RATES OR ANNUAL ENERGY SAVINGS?

A. No. The Company's proposals carry no penalties for failure to attain its estimated energy savings, participation rates, or cost effectiveness results. The program has no direct accountability process commonly referred to as monitoring and verification or "M&V."

Q. WHY IS M&V IMPORTANT FOR ENERGY EFFICIENCY PROGRAMS?

A. M&V provides valuable information to the Company, the TRA, the Consumer Advocate, and other stakeholder groups about the viability, cost effectiveness, and success of the implemented programs. Successful M&V can also provide important input for future program adjustments (expansions and contractions) as well as other program design, delivery, and efficiency improvements.

Q. ARE THE COMPANY'S PROPOSED ENERGY EFFICIENCY PROGRAMS SUFFICIENT TO JUSTIFY THE DECOUPLING TRACKER?

A. Not in their present form. The Company has presented no evidence that the projected participation in these programs and resulting decline in customer usage will affect its revenues to the point where the decoupling mechanism is necessary. As discussed above, the Company projects that with the energy efficiency programs and decoupling mechanism customer usage will decline to under 74 Dths over the next three years. In response to a question regarding projected residential usage should the decoupling mechanism and energy efficiency programs not be approved by the Authority, the Company stated:

> Projecting residential usage per customer is a difficult task since usage patterns vary each year due to conservation education, price elasticity, weather patterns and various other factors. Based on the figures cited in response to question #2 [*annual usage March 31,*

> *2005 through March 31, 2009*] and the overall downward trend in normalized residential usage per customer that we are witnessing in our markets, the Company would project normalized residential usage per customer over the next three years to be near 74 DTs per customer.[71]

Thus the Company sees the impact of implementing its proposals or not implementing them, in conjunction with other factors such as education, price elasticity and weather, as approximately 0.5[72] Dth per residential customer. Yet nowhere in its Petition has the Company stated what it believes to be the decrease in usage attributable solely to these programs.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the TRA reject the Company's MDT since the energy efficiency programs offered in return for this mechanism are small in scale and scope, have not been accurately documented and examined, and fail to include any form of accountability. However, if the TRA has lingering concerns about any possible (yet unproven) financial implications of these programs, it should allow the Company to recover verifiable lost base revenues associated with its energy efficiency programs and verified in a well defined M&V process.

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

[71] Response to TRA Data Request 1-3.

[72] Response to TRA Data Request 1-2, shows usage of 74.4 Dth for the 12 months ending March 2009 and 74.63 Dth for the 12 months ending March 2008.

$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.

Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS IF THE AUTHORITY FINDS THAT A LOST REVENUE APPROACH IS NOT APPROPRIATE?

A. Yes. If the Authority does not adopt a lost revenue approach, it may want to move towards a more progressive policy, that provides direct incentives to the Company for reaching certain energy efficiency targets.

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

A. Three options the TRA could consider include:

- An incentive-based approach that would base the target goals on an achieved benefit/cost ("B/C") ratio.
- An incentive-based approach that offers rewards for reaching a forecasted level of total natural gas savings.
- An incentive-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 INCENTIVE REGULATION ALTERNATIVE?

A. The first alternative is an incentive-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.[73]

Q. CAN YOU EXPLAIN THE SECOND ALTERNATIVE?

A. The second alternative is a more traditional DSM incentive-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

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

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-14. 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 utility's performance relative to an approved savings target (Dth per dollar spent).[74]

Q. HAVE ANY STATES TIED REVENUE DECOUPLING ADOPTION TO THE ADOPTION OF STRONG ENERGY EFFICIENCY PROGRAMS AND TARGETS?

A. Yes. In several jurisdictions, implementation of decoupling mechanisms is tied to the results of energy efficiency programs. For example, in Washington State, the natural gas distribution company Avista Utilities ("Avista") requested approval of a pilot revenue decoupling program. Avista set its gas savings targets as part of its 2006 Integrated Resource Plan ("IRP") with the assistance of an external group, the External Energy Efficiency Board. The decoupling

[74] 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.

mechanism, as stipulated to by parties in the docket, included a test whereby Avista must achieve at least the 2006 IRP targeted gas savings to maximize recovery of deferred costs. [75]

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. [76]

Q. WHAT OTHER STATES HAVE SIMILAR INCENTIVE MECHANISMS?

A. As depicted on Exhibit DED-14, 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"). The RRIM is an incentive mechanism designed to align shareholder and

[75] Washington Utilities and Transportation Commission, Docket UG-060518, Order 04, February 1, 2007.

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

consumer interests. It "provides both a meaningful level of shareholder earnings and a return on ratepayers' investment in energy efficiency." [77]

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).[78]

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.[79]

Q. WOULD YOU DESCRIBE THE THIRD ALTERNATIVE?

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[77] 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.

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

[79] 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.

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.

Q. COULD A SPECIFIC INCENTIVE-BASED APPROACH BE ADOPTED IN THIS PROCEEDING?

A. No. I would recommend against any type of incentive-based mechanism at this time given the lack of analyses and documentation provided in the Company's filing regarding its energy efficiency program. However, if the TRA decides to consider this issue in a future rate case, or some other form of future filing requirement, then any of the three methods that I outlined earlier could be effective provided the appropriate support, documentation, and M&V protocols are included.

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR GENERAL RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED MARGIN DECOUPLING TRACKER?

A. I recommend that the TRA reject the Company's proposed Margin Decoupling Tracker ("MDT" or "revenue decoupling proposal") for the following reasons:

- The Company's MDT would transfer a considerable amount of sales risk away from shareholders and towards ratepayers with virtually no reciprocal, nor proportional, benefits.
- The Company's revenue decoupling proposal includes virtually 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. 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.
- If the TRA would like to actively promote energy efficiency, I recommend that a performance-based mechanism that rewards Piedmont for greater-than-average success at achieving its energy efficiency potentials be adopted. Such an approach, however, cannot be adopted in this proceeding given the deficiency in the Company's energy efficiency filings. If the TRA decides to move forward with an incentive-based approach, I recommend that it direct the Company make a future incentive-based filing that ties rewards to the Company's energy efficiency performance. This incentive-based filing should also include a comprehensive and documentable portfolio of energy efficiency programs.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes, if the TRA decides to adopt the Company's MDT, I recommend that it direct the Company to modify and re-file its proposal within the context of a general rate case. The minimum filing requirements for this rate case should include at least the following:

- The Company's determination of its proposed initial target revenues (margins) per customer for each rate class;
- The factors that the Company proposes to use to annually adjust its target revenues (margins) for each rate class;
- The manner in which the Company's proposed mechanism treats customers receiving new distribution service during a particular year, to the extent that the Company determines that the costs of providing service to new customers differs from the costs of providing service to existing customers;
- A tariff showing the manner in which the Company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;
- Include a total revenue decoupling account balance cap that is no greater than 2.0 percent of total base revenues;
- An analysis of how changes in risk resulting from the adoption of revenue decoupling have been taken into consideration in the determination of its proposed Return on Equity ("ROE");

- A full analysis of the potential and cost-effective energy efficiency opportunities in its service territory with supporting documentation on how these estimates have been developed; and
- A complete energy efficiency plan that includes cost effectiveness findings for each major energy efficiency measure/program being proposed and a proposed energy efficiency/revenue decoupling review process including goals, targets, and benchmarks.

Q. WHAT IF THE TRA DECIDES TO ADOPT REVENUE DECOUPLING WITHIN THIS PROCEEDING AND NOT A FULL RATE CASE?

A. Then I recommend the TRA modify the Company's current proposal in the following manner:

- Utilize the billing determinants estimated with more contemporaneous load and weather information that is provided in Exhibit DED-7.
- 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 only those amounts in excess of the recent changes in the Company's Use Per Customer ("UPC"). Revenue recovery should only occur if UPC changes by more than 0.9 percent per year and then it should be restricted to the difference between the actual UPC percent change and a 0.9 percent threshold level.
- 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 filings with the Authority which are in the same format as provided in North Carolina. In addition, the Company should make annual filings 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.

- The Company should be required to develop performance metrics and report these metrics to the TRA annually.
- To the extent there is a contested rate case or earnings review within the three year review period, the TRA should also examine the merits, and any potential modifications, of the MDT in that proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON DECEMBER 4, 2009?

A. Yes.

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

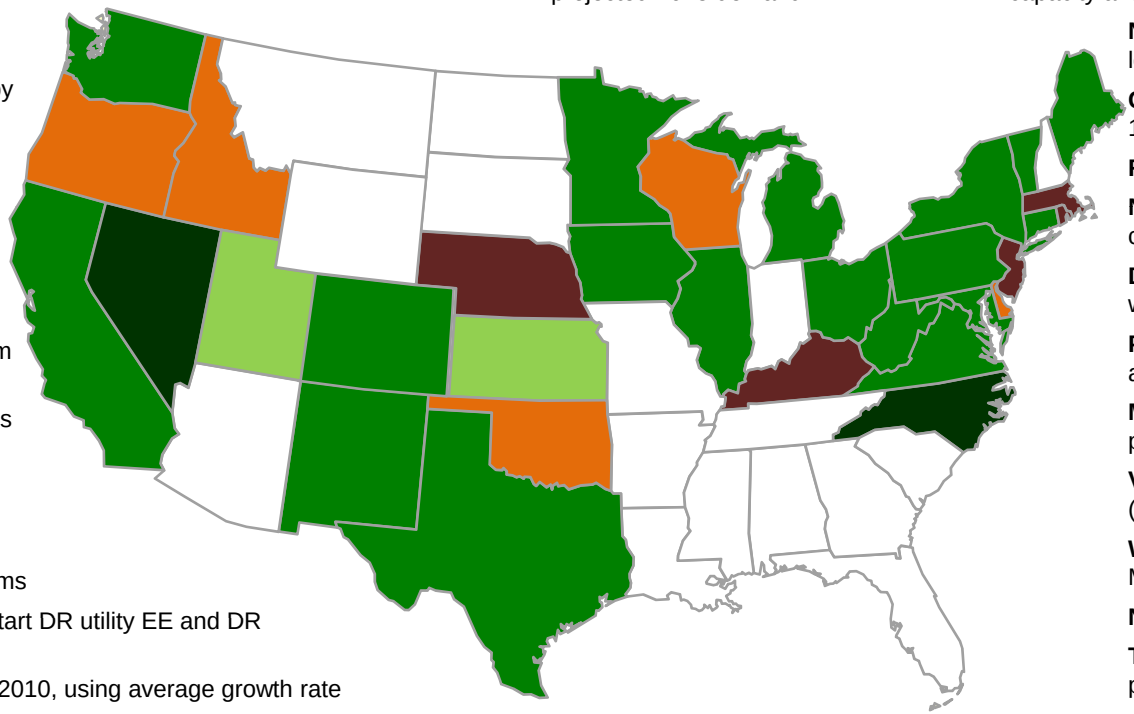
OH: 22% energy savings by 2025 (from '09); reduce peak 8% by 2018

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

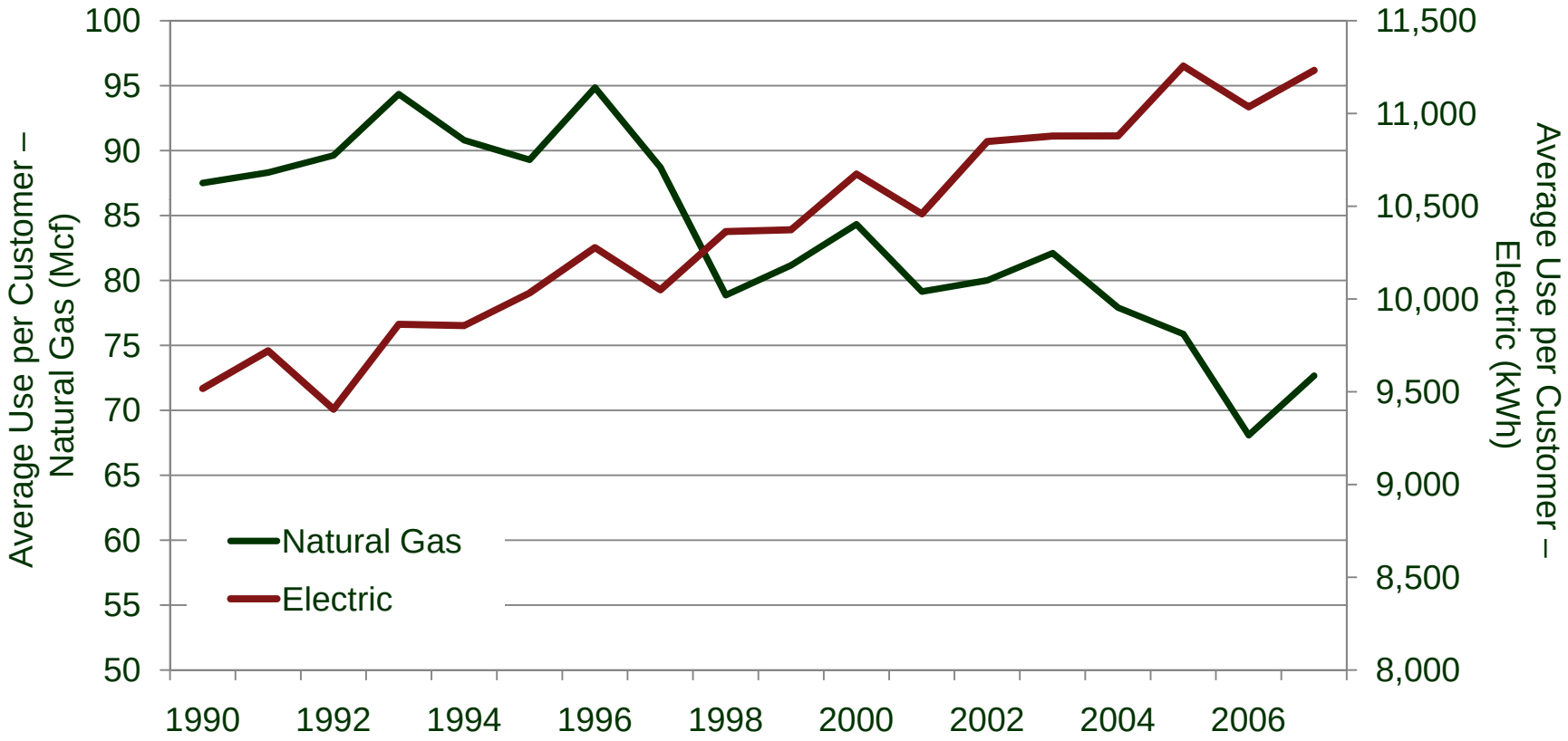
NC: EE to meet up to 25% of RPS by 2011

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

U.S. Average Residential Use Per Customer
Natural Gas and Electric



Source: Energy Information Administration, U.S. Department of Energy.

Overview of Natural Gas DSM Programs, 2004

	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

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.

Piedmont Natural Gas Company
Estimated Revenue Impacts

Total Revenues, Customer, and Usage

	Residential				Change in Use		Revenue Impact		
	Number of Customers	Sales (Dth)	Use per Customer (Dth)	Distribution Revenue* ($)	Average Use from Existing Customers ----- (Dth) -----	Number of New Customers	Use per Customer ---------- ($) ----------	Customers	Total
2002	129,949	10,350,927	79.7	$ 39,285,706					
2003	133,007	10,636,222	80.0	$ 43,926,105	40,827	244,468	$ 212,076	$ 1,009,618	$ 1,221,694
2004	135,779	10,369,511	76.4	$ 37,116,901	(478,411)	211,700	$ (1,785,647)	$ 757,764	$ (1,027,883)
2005	138,513	10,519,595	75.9	$ 32,653,048	(57,554)	207,639	$ (243,200)	$ 644,515	$ 401,316
2006	141,257	9,758,578	69.1	$ 31,436,770	(950,601)	189,584	$ (3,046,050)	$ 610,734	$ (2,435,316)
2007	144,134	9,845,494	68.3	$ 49,719,754	(109,589)	196,506	$ (295,128)	$ 992,353	$ 697,225
2008	146,567	11,060,911	75.5	$ 29,829,131	1,031,750	183,666	$ 2,443,256	$ 495,313	$ 2,938,569

Estimated Base Revenues, Customer, and Usage */1

	Residential				Change in Use		Revenue Impact		
	Number of Customers	Sales (Dth)	Use per Customer (Dth)	Distribution Revenue* ($)	Average Use from Existing Customers ----- (Dth) -----	Number of New Customers	Use per Customer ---------- ($) ----------	Customers	Total
2002	129,949	10,350,927	79.7	$ 39,285,706					
2003	133,007	10,636,222	80.0	$ 43,926,105	40,827	244,468	$ 212,076	$ 1,009,618	$ 1,221,694
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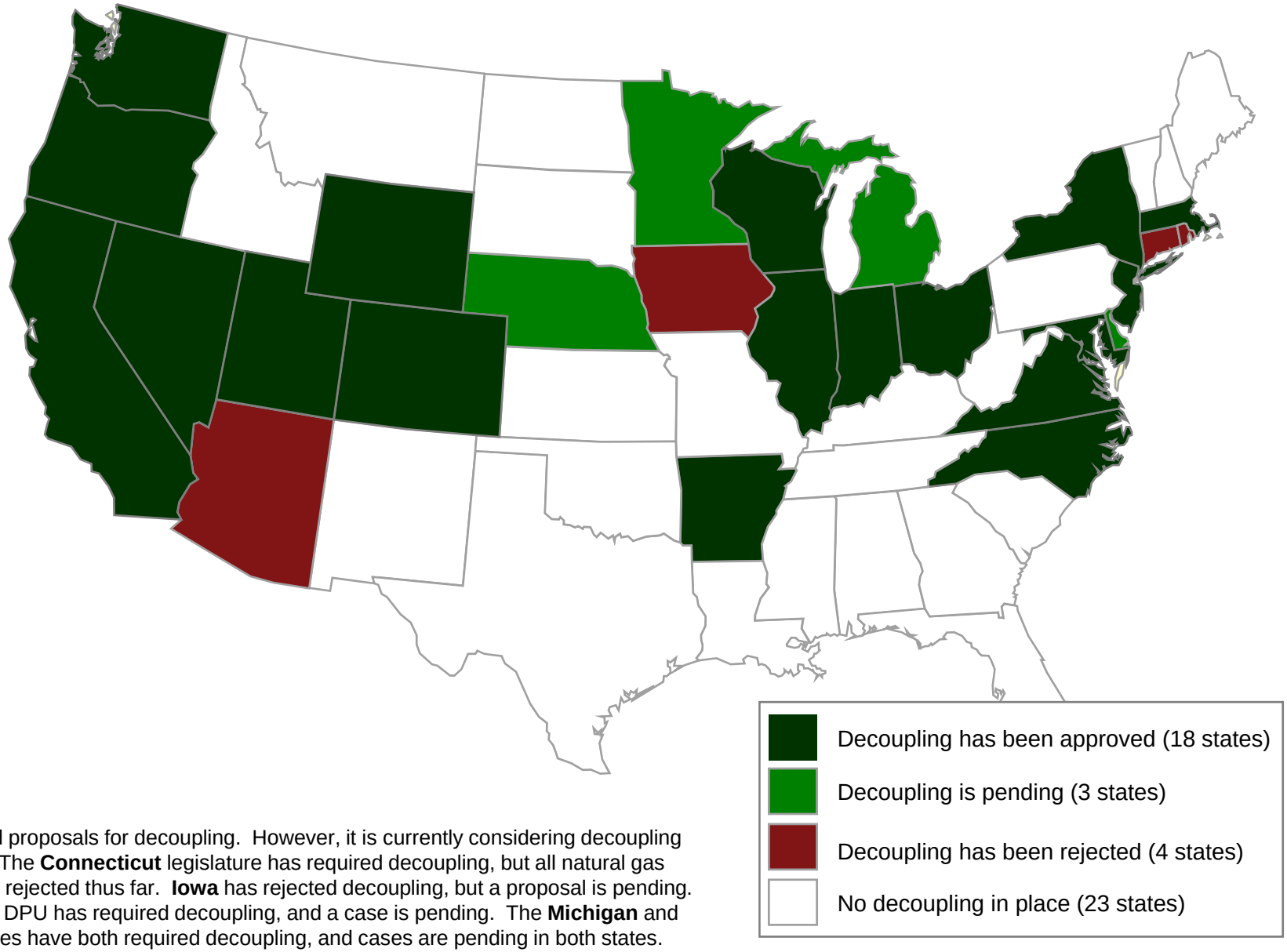
2005	138,513	10,519,595	75.9	$ 32,653,048	(57,554)	207,639	$ (243,200)	$ 644,515	$ 401,316
2006	141,257	9,758,578	69.1	$ 31,436,770	(950,601)	189,584	$ (3,046,050)	$ 610,734	$ (2,435,316)
2007	144,134	9,845,494	68.3	$ 49,719,754	(109,589)	196,506	$ (295,128)	$ 992,353	$ 697,225
2008	146,567	11,060,911	75.5	$ 29,829,131	1,031,750	183,666	$ 2,443,256	$ 495,313	$ 2,938,569

Note: */1 Estimated base revenues are calculated using Tennessee operating revenues and estimated cost of gas.
Source: Attachment 1 - Response to CAD Data Request , Item #1-41, Piedmont Form TN 303; and Piedmont FERC Form 1

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. The **Massachusetts** DPU has required decoupling, and a case is pending. The **Michigan** and **Minnesota** legislatures have both required decoupling, and cases are pending in both states.

Piedmont Natural Gas Company
Margin Decoupling Deferred Account Adjustment Calculation, March 2009

Line No.	Description		Formula Using Line Nos.	Residential Value Service Rate Schedule No. 301	Residential Std. Service Rate Schedule No. 321	Total
1	Normal Degree Days [1]			513.3	513.3	
2	Base Load [2]	(th/month)		23.08653	3.91564	
3	Heat Sensitivity Factor [2]	(th/HDD)		0.21337	0.15957	
4	Usage/HDD/Customer	(th)	(1x3)+2=	133	86	
	RATE CASE					
5	No. of Customers (Actual)			54,242	94,200	
6	Total Normalized Usage	(th)	(4x5)=	7,218,880	8,093,253	15,312,133
7	R Factor [3]	($/th)		$0.32000	$0.32000	
8	Normalized Margin	($)	(6x7)=	$2,310,042	$2,589,841	$4,899,883
	ACTUAL					
9	No. of Customers (Actual)			54,242	94,200	
10	Actual Usage	(th)		7,698,184	9,051,156	16,749,340
11	R Factor [3]	($/th)		$0.32000	$0.32000	
12	Actual Margin	($)	(10x11)=	$2,463,419	$2,896,370	$5,359,789
13	Actual WNA	($)		$43,921	$86,871	$130,792
14	**Margin Decoupling Deferred Account Adjustment**	**($)**	**(8-12-13)=**	**($197,298)**	**($393,400)**	**($590,698)**

Note: [1] Used in the calculation of the COS and final rates approved in TRA Docket 03-00313.
[2] From Docket No. 03-00313, TRA Order dated 7/15/2004, pg. 13.
[3] From Docket No. 03-00313, TRA Order dated 7/15/2004, pg. 15.
Source: Response 9_workbook FY09.xls.

Piedmont Natural Gas Company
Margin Decoupling Deferred Account Adjustment Calculation, April 2009

Line No.	Description		Formula Using Line Nos.	Residential Value Service Rate Schedule No. 301	Residential Std. Service Rate Schedule No. 321	Total
1	Normal Degree Days [1]			331.6	331.6	
2	Base Load [2]	(th/month)		23.08653	3.91564	
3	Heat Sensitivity Factor [2]	(th/HDD)		0.21337	0.15957	
4	Usage/HDD/Customer	(th)	(1x3)+2=	94	57	
	RATE CASE					
5	No. of Customers (Actual)			54,160	93,611	
6	Total Normalized Usage	(th)	(4x5)=	5,095,726	5,327,930	10,423,656
7	R Factor [3]	($/th)		$0.27000	$0.27000	
8	Normalized Margin	($)	(6x7)=	$1,375,846	$1,438,541	$2,814,387
	ACTUAL					
9	No. of Customers (Actual)			54,160	93,611	
10	Actual Usage	(th)		4,250,914	4,558,239	8,809,153
11	R Factor [3]	($/th)		$0.27000	$0.27000	
12	Actual Margin	($)	(10x11)=	$1,147,747	$1,230,725	$2,378,472
13	Actual WNA	($)		$0	$0	$0
14	**Margin Decoupling Deferred Account Adjustment**	**($)**	**(8-12-13)=**	**$228,099**	**$207,816**	**$435,915**

Note: [1] Used in the calculation of the COS and final rates approved in TRA Docket 03-00313.
[2] From Docket No. 03-00313, TRA Order dated 7/15/2004, pg. 13.
[3] From Docket No. 03-00313, TRA Order dated 7/15/2004, pg. 15.
Source: Response 9_workbook FY09.xls.

Piedmont Natural Gas Company
Margin Decoupling Deferred Account Activity

	Residential Value Rate 301	Residential Standard Rate 301	Total
March 2009			
Beginning Balance - March 1, 2009	$ -	$ -	$ -
Margin Decoupling Adjustment	$ (197,298)	$ (393,400)	$ (590,698)
Decrement (Increment)	$ -	$ -	$ -
Ending Balance Before Interest	$ (197,298)	$ (393,400)	$ (590,698)
Accrued Interest	$ (267)	$ (533)	$ (800)
Total Due From (To) Customers	$ (197,565)	$ (393,933)	$ (591,498)
April 2009			
Beginning Balance - April 1, 2009	$ (197,565)	$ (393,933)	$ (591,498)
Margin Decoupling Adjustment	$ 228,099	$ 207,816	$ 435,915
Decrement (Increment)	$ -	$ -	$ -
Ending Balance Before Interest	$ 30,534	$ (186,117)	$ (155,583)
Accrued Interest	$ (226)	$ (785)	$ (1,011)
Total Due From (To) Customers	$ 30,308	$ (186,902)	$ (156,594)

Source: TRA 1-1 Attachment

Piedmont Natural Gas Company, Inc.
Recommended NDD, Base Load, and Heat Sensitivity Factor

Witness: Dismukes
Docket No. 09-00104
Exhibit DED-7

Description			Residential Value Service Rate Schedule No. 301	Residential Std. Service Rate Schedule No. 321
Base Load	**(th/month)**		20.27586	4.02783
Heat Sensitivity Factor	**(th/HDD)**		0.20785	0.15669
Normal Degree Days Ending September 2009				
	Oct	79		
	Nov	312		
	Dec	574		
	Jan	790		
	Feb	808		
	Mar	500		
	Apr	328		
	May	109		
	Jun	15		
	Jul	0		
	Aug	0		
	Sep	1		
Total NDD		**3,515**		

Piedmont Natural Gas Company
Estimated Cost to Serve Customers

Public Version

	Actual						All Existing
	2004	2005	2006	2007	2008	2009	2008
	($)						
Meters	[redacted]						
Services							
Regulators							
Manager Approved							
Revenue Producing							
Total							
Customer Additions							
Cost per Customer							

Source: Response to CAD Data Request, Item #1-33, Attachment 1.

Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decouping - Gas/ Electric	Date of Decision	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Arkansas Oklahoma Gas (AR)	Gas	Gas	11/20/07		XXX			
Arkansas Western Gas (AR)	Gas	Gas	06/01/07		XXX		XXX	
CenterPoint Energy (AR)	Gas	Gas	10/25/07		XXX			
PSC of Colorado (CO)	Electric & Gas	Gas	06/18/07	XXX	XXX		XXX	
United Illuminating (CT)	Electric	Electric	02/04/09	XXX		XXX		XXX
Idaho Power (ID)	Electric	Electric	03/12/07	XXX		XXX	XXX	
North Shore Gas Company (IL)	Gas	Gas	02/05/08	XXX			XXX	XXX
Peoples Gas Light and Coke (IL)	Electric & Gas	Gas	02/05/08	XXX			XXX	XXX
Citizens Energy (IN)	Gas	Gas	08/29/07			XXX	XXX	
Vectren Southern Indiana Gas (IN)	Gas	Gas	12/01/06	XXX	XXX	XXX	XXX	
Vectren Indiana Gas (IN)	Gas	Gas	12/01/06	XXX	XXX	XXX	XXX	
Bay State Gas (MA)	Gas	Gas	10/30/09	XXX				
Baltimore Gas & Electric (MD)	Electric & Gas	Gas	02/27/98					
Delmarva Power & Light (MD)	Electric	Electric	07/19/07					
PEPCO (MD)	Electric	Electric	07/19/07					
Washington Gas (MD)	Gas	Gas	08/11/05					
Southwest Gas (NV)	Gas	Gas	11/03/09			XXX		
New Jersey Natural (NJ)	Gas	Gas	10/12/06	XXX	XXX	XXX	XXX	
South Jersey Gas (NJ)	Gas	Gas	10/12/06	XXX	XXX	XXX	XXX	
Consolidated Edison (NY)	Electric & Gas	Electric & Gas	9/25/07 & 3/25/08			XXX	XXX	
National Gas Distribution (NY)	Gas	Gas	09/20/07			XXX		
Orange and Rockland (NY)	Electric & Gas	Electric	7/23/2008					
Piedmont Natural Gas (NC)	Gas	Gas	11/3/05 & 10/23/08			XXX	XXX	
PSC of North Carolina (NC)	Gas	Gas	10/24/08			XXX		
Vectren (OH)	Gas	Gas	09/13/06			XXX	XXX	XXX
Cascade Natural Gas (OR)	Gas	Gas	04/19/06		XXX	XXX	XXX	XXX
Northwest Natural (OR)	Gas	Gas	09/12/02	XXX		XXX	XXX	
Portland General Electric (OR)	Electric	Electric	01/22/09	XXX		XXX	XXX	XXX
Questar Gas (UT)	Gas	Gas	10/5/06 & 11/5/07			XXX	XXX	XXX
Virginia Natural (VA)	Gas	Gas	12/23/08			XXX	XXX	XXX
Green Mountain Power (VT)	Electric	Electric	12/22/06	XXX	XXX	XXX	XXX	
Avista (WA)	Gas	Gas	2/1/07 & 4/4/06	XXX	XXX	XXX	XXX	XXX
Cascade Natural Gas (WA)	Gas	Gas	01/12/07		XXX	XXX	XXX	XXX
Wisconsin Public Service (WI)	Electric & Gas	Electric & Gas	12/30/08	XXX		XXX	XXX	XXX
Questar Gas (WY)	Gas	Gas	06/17/09			XXX	XXX	XXX

Illustrative Consumer Protection Mechanism

	Annual Use per Customer	Annual Change	Annual Percent Change	Percent Change from Base	Threshold	Net Adjustment
	------ (Dth) ------			---------- (%) ----------		
2009	79.5					
2010	79.4	(0.10)	-0.1%	-0.1%	0.9%	0.0%
2011	78.3	(1.10)	-1.4%	-1.5%	1.9%	0.0%
2012	77.1	(1.20)	-1.5%	-3.0%	2.8%	0.2%
2013	75.6	(1.50)	-1.9%	-4.9%	3.8%	1.1%
2014	75.1	(0.50)	-0.7%	-5.5%	4.7%	0.8%

Piedmont Natural Gas Company
Results of Tennessee Operations

Description	Tennessee Gas Operations						
	2002	2003	2004	2005	2006	2007	2008
Utility Gas Operating Revenues							
System Distribution Gas Revenue	$ 152,662,529	$ 208,639,739	$ 204,774,964	$ 263,526,320	$ 212,295,100	$ 227,124,094	$ 276,389,424
General Related Other Revenue	7,907,162	24,724,540	30,948,512	30,396,457	32,745,617	5,493,908	51,713,022
	$ 160,569,691	$ 233,364,279	$ 235,723,476	$ 293,922,777	$ 245,040,717	$ 232,618,002	$ 328,102,446
Utility Operating Expenses							
O&M and Depreciation and Amortization							
Purchased Gas, Storage and Production	$ 79,562,463	$ 141,814,526	$ 140,453,742	$ 200,186,433	$ 151,266,102	$ 141,285,181	$ 226,311,082
Transmission and Distribution - Operation	6,089,499	6,241,385	6,703,203	6,292,474	6,456,582	7,077,818	6,858,578
Transmission and Distribution - Maintenance	4,569,344	4,714,238	4,955,216	5,306,390	4,917,701	4,407,425	4,610,560
Customer Accounts Expenses	4,803,561	5,099,318	4,979,142	5,733,195	6,502,691	4,881,084	3,217,151
Sales Expenses	1,532,971	1,349,008	1,075,637	1,074,335	793,539	861,004	1,084,307
Administrative and General Expenses	15,350,088	16,488,471	15,252,474	15,873,966	17,644,988	17,337,642	17,514,642
Total O&M	$ 111,907,926	$ 175,706,946	$ 173,419,414	$ 234,466,793	$ 187,581,603	$ 175,850,154	$ 259,596,320
Depreciation and Amortization	$ 16,601,981	$ 17,141,775	$ 17,570,322	$ 18,786,702	$ 20,237,625	$ 20,004,905	$ 20,440,970
Other Operating Expenses							
Taxes Other Than Income Taxes	8,073,071	7,888,516	6,121,386	7,662,159	9,874,577	9,280,764	9,075,074
Fed & State Income Taxes	5,289,462	9,095,381	11,537,687	8,945,460	5,725,697	6,135,867	10,693,442
Total Other Operating Expenses	$ 13,362,533	$ 16,983,897	$ 17,659,073	$ 16,607,619	$ 15,600,274	$ 15,416,631	$ 19,768,516
Total Utility Operating Expenses	$ 141,872,440	$ 209,832,618	$ 208,648,809	$ 269,861,114	$ 223,419,502	$ 211,271,690	$ 299,805,806
NET OPERATING INCOME (NOI)	$ 18,697,251	$ 23,531,661	$ 27,074,667	$ 24,061,663	$ 21,621,215	$ 21,346,312	$ 28,296,640
Other Income	154,271	167,847	(795,788)	203,128	220,987	312,439	58,783
Miscellaneous Income Deductions	-	-	-	-	-	-	-
Interest Charges	10,011,702	9,168,088	8,977,687	10,121,182	12,506,492	11,839,085	12,460,998
NET INCOME	$ 8,839,820	$ 14,531,420	$ 17,301,192	$ 14,143,609	$ 9,335,710	$ 9,819,666	$ 15,894,425

Piedmont Natural Gas Company
Results of Tennessee Operations

Description	Tennessee Gas Operations						
	2002	2003	2004	2005	2006	2007	2008
Average Utility Plant							
Plant in Service	429,471,940	441,579,490	458,840,230	480,436,124	507,270,116	527,507,522	539,471,044
Construction Work in Progress	12,690,832	15,039,263	15,860,550	16,990,723	16,171,196	10,932,498	13,885,015
Gas Inventory	3,053,204	3,578,617	19,065,812	23,902,781	22,248,001	24,447,015	28,873,667
Total Utility Plant	$ 445,215,976	$ 460,197,370	$ 493,766,592	$ 521,329,628	$ 545,689,313	$ 562,887,035	$ 582,229,726
Accumulated Depreciation	171,549,133	185,222,341	198,140,064	213,713,295	229,597,461	242,842,489	261,301,657
Accumulated Deferred Income Taxes	19,836,552	23,048,560	31,116,541	33,982,732	35,772,453	41,993,767	38,182,269
Unamortized Investment Credit - Pre 1971	948	552,440	403,965	253,399	102,833	2,501	-
Working Capital	279,591	279,591	6,958,963	6,958,963	6,958,963	6,958,963	6,958,963
Contributions in Aid of Construction	4,345,141	4,433,425	4,490,721	4,569,442	4,624,033	4,770,930	5,000,374
Customer Advances	187,175	187,174	187,174	187,174	187,175	124,783	-
RATE BASE	$ 249,017,436	$ 246,473,839	$ 252,469,164	$ 261,664,623	$ 268,446,395	$ 266,193,602	$ 270,786,463
Net Operating Income	$ 18,697,251	$ 23,531,661	$ 27,074,667	$ 24,061,663	$ 21,621,215	$ 21,346,312	$ 28,296,640
Adjustments to Net Operating Income							
Allowance for Funds Used During Construction	$ 175,992	$ 150,097	$ 162,543	$ 154,918	$ 217,369	$ 20,537	$ 1,597
Interest on Customer Deposits	(138,820)	(137,961)	(169,577)	(189,268)	(205,882)	(19,502)	(19,837)
IPA Sharing	(841,785)	(846,286)	(977,600)	(977,600)	(977,600)	(632,802)	(771,505)
Pension Funding Deferral	-	-		(884,438)	(715,791)	(925,741)	(1,148,301)
Change in Accounting Estimate (Unbilled Revenue)		(3,926,365)					
General Taxes - Equalization Litigation Refund			(1,089,810)				
Gross Receipts			(758,338)				
Prior Period Adjustments [(1)]							
Long Term Incentive Plan	291,431	337,980	199,237	243,573	262,036	71,171	329,434
Adjusted Net Operating Income	$ 18,184,069	$ 19,109,126	$ 24,441,122	$ 22,408,848	$ 20,201,347	$ 19,859,975	$ 26,688,028
Achieved Return on Rate Base	7.30%	7.75%	9.68%	8.56%	7.53%	7.46%	9.86%
Allowed Return on Rate Base	9.56%	9.56%	8.42%	8.42%	8.42%	8.42%	8.42%
Difference Between Achieved and Allowed	-2.26%	-1.81%	1.26%	0.14%	-0.89%	-0.96%	1.44%

Note: [1]Prior Period Adjustments were excluded from 2008 NOI calculation as it was not evident they would be approved for ratemaking purposes.
Source: Company's Form TN 303; Docket 99-00994, Order Schedule VI; Docket 03-00313, Order p. 10.

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
NATURAL GAS					
Arkansas Oklahoma Gas (AR)	Docket No. 07-026-U	Billing Determinant Adjustment	Staff recommended a 25 basis point discount which "recognizes the reduced risk associated with adoption of a decoupling rate mechanism." The AG stated that a "significant reduction of the return on equity must accompany a rider of this type, because a lower risk equals a lower return."	Settlement	ROE reduced 10 basis points
Arkansas Western (AR)	Docket No. 06-124-U	Billing Determinant Adjustment	Staff recommended that "a commensurate reduction of 25 basis points should be made to AWG's return on equity". The AG also recommended 25 basis point reduction.	Settlement	ROE reduced 25 basis points
CenterPoint Energy (AR)	Docket No. 06-161-U	Billing Determinant Adjustment	Staff recommended "a further reduction of 25 basis points" if the BDA tariff is approved.	Settlement	ROE reduced 10 basis points
Southwest Gas (AZ)	Docket No. G-01551A-07-0504	Revenue Decoupling	The Staff witness testified that "the only thing the Company wants to achieve through its proposed rate design is avoidance of financial risk, nothing more nothing less." Staff argued that the shift of risk from shareholders to ratepayers, if decoupling were to be adopted, would necessitate a downward adjustment to the authorized return on equity.	Final Order	Decoupling was not adopted, no adjustment was made
Public Service Company of Colorado (CO)	Docket No. 06S-565G	Partial Decoupling Rate Adjustment Mechanism	The OCC witness recommended a lower ROE if the Commission approved Public Service's decoupling proposal.	Settlement	No adjustment was made
Connecticut Natural Gas (CT)	Docket No. 08-12-06	Revenue Decoupling	The OCC witness testified that “[t]he adoption of such a mechanism should serve to reduce the volatility of a company’s revenues and earned ROE. A reduction in volatility reduces the riskiness of an enterprise.” OCC recommended a 25 basis point reduction in the authorized ROE “to reflect the reduction in risk.”	Final Order	Decoupling was not adopted, no adjustment was made

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
Delmarva Power & Light Company (DE)	Docket No. 06-284	Bill Stabilization Adjustment	The Delmarva witness recommended "the adoption of an overall return on investment of 8.08% and a rate of return on common equity of 11.0% on DP&L's natural gas delivery operations, assuming that the Bill Stabilization Adjustment ("BSA") is adopted. If the BSA adopted is not approved, I recommend the adoption of an overall return on investment of 8.20% and a rate of return on common equity of 11.25% on DP&L's natural gas delivery operations."	Settlement	BSA was not adopted, no adjustment was made
North Shore Gas Company; and Peoples Gas Light and Coke (IL)	Docket No. 07-241 and 07-242	Volume Balancing Adjustment	Staff and City-CUB argue that authorized rates of return should be reduced to reflect the resulting reduced risk. “In particular, Staff asserts the riders would reduce operating risk, which the Utilities acknowledge is part of investment risk.” The Commission finds that Rider VBA “will lesson Utilities’ risk associated with their cash flow” and “this warrants a reduction.”	Final Order	ROE reduced 10 basis points
NICOR Gas (IL)	Docket No. 08-0363	80% SFV	The Commission believes “that adopting this rate design will clearly reduce Nicor‘s risk.” “Thus, in determining Nicor‘s authorized return on common equity in this proceeding, we conclude that it necessary and appropriate to deduct 6.5 basis points to reflect the reduction in Nicor's risk.”	Final Order	ROE reduced 6.5 basis points
Vectren Indiana Gas and Vectren Southern Indiana Gas (IN)	Cause No. 42943 and 43036	Energy Efficiency Rider with Sales Reconciliation Component	The Commission stated that by approving the riders “we are once again approving mechanisms that alleviate risk for Petitioners. When asked by the presiding judge whether Petitioners believe that this will result in a reduction in risk, Petitioner's witness Benkert responded "yes". We have not as yet required a corresponding reduction in the cost of equity, as have some states. The benefits that inure to Petitioners by approving this Plan are clear. We find that there needs to be a corresponding benefit to the consumers.”	Settlement	No adjustment was made
Kansas General Investigation	Docket No. 08-GIMX-441-GIV	Decoupling	“As with decoupling, the Commission anticipates considering some reduction in rate of return as a result of the decreased risk.”	Final Order	To be determined

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
Bay State Gas (MA)	Docket No. D.P.U. 09-30	Decoupling	The AG's witness "estimated the equity capital cost of the Company's gas utility operations should be reduced by at least 50 basis points to account for the reduction in operating risk afforded by decoupling."	Final Order	no adjustment was made
Missouri Gas Energy (MO)	Docket No. GR-2006-0422	SFV	"Staff and MGE agree that the value of the SFV rate design is 30-35 basis points. As these suggestions are estimates, the Commission finds that the value of the SFV rate design is 32.5 points."	Settlement	ROE reduced 32.5 basis points.
Southwest Gas (NV)	Docket No. 09-040003	Revenue Decoupling	"Southwest acknowledged that revenue stabilization mechanisms, such as decoupling, reduce risk and proposed a minimal reduction of 10 basis points to the ROE." Staff testified that the reduction should be between 20 and 70 points. The Commission found that "a 25 basis point reduction is adequate to maintain Southwest's financial viability and is sufficient to allow it to raise the capital necessary to provide adequate, safe and reliable service."	Final Order	ROE reduced 25 basis points.
Consolidated Edison (NY)	Case No. 06-G-1332	Revenue Decoupling Mechanism (RDM)	Public Utility Law Project notes that the existence of an RDM "shifts a substantial risk of revenue shortfalls from the utility to the ratepayers" and the ROE should be reduced proportionately.	Settlement	no adjustment was made
National Fuel Gas Distribution Co (NY)	Case No. 07-G-0141	Revenue Decoupling Mechanism (RDM)	Staff, multiple intervenors and CPB support a 25 basis point reduction to the allowed rate of return. The Commission stated that given it is adopting the RDM "that most of the companies in Staff's proxy group do not have revenue decoupling mechanisms, and that the effects of revenue decoupling mechanisms have long been considered by investors and factored into the financial market data for natural gas firms, we will apply a 10 basis points reduction."	Final Order	ROE reduced 10 basis points
Portland General Electric Co (OR)	Docket UE-197	Decoupling	In approving the Company's decoupling mechanism, the Commission reduced the utility's ROE by 10 basis points "to reflect the reduction in the Company's risk"	Final Order	ROE reduced 10 basis points

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
Chattanooga Gas (TN)	Docket No. 06-00175	Conservation and Usage Adjustment	The Chattanooga witness stated, "[i]f the proposed CUA and PRP mechanisms are approved, the Company's risk will be reduced, and the cost of common equity capital likely will decline by some 50 basis points from 11.5% to 11.0%."	Settlement	CUA was not adopted, no adjustment was made.
Cascade Natural Gas (WA)	Docket No. UG-060256	Partial Decoupling	Staff recommended adjusting the ROE downward by 25 basis points. In settlement Cascade and Staff "assert that the negotiated [ROE] result includes the effect of an unquantifiable reduction in risk associated with the Settlement's decoupling proposal." The Commission stated, "[w]hile the exact adjustment is not clear, the evidence demonstrates that the stipulated rate of return includes a risk adjustment."	Settlement	Unidentified reduction
ELECTRIC					
United Illuminating (CT)	Docket No. 08-07-04	Decoupling	Although the Department did not explicitly make a downward adjustment to the ROE to account for a decoupling mechanism, it confirmed a lower ROE is necessary in this proceeding: "[t]he implementation of a decoupling mechanism further mitigates the earnings pressure of the Company having the impact of reducing the overall risk profile of UI. Risk is also reduced in this proceeding since the portion of distribution costs collected through fixed customer service and demand charges was increased. The collection of costs through fixed charges rather than energy charges reduces the variability of earnings associated with sales."	Final Order	Unidentified
Idaho Power (ID)	Case No. IPC-E-04-15	Fixed Cost Adjustment	ICAN recommended an adjustment of 50 basis points. The Commission stated that the recommended ROE adjustment is a general rate case issue and can be addressed in the Company's next rate case.	Settlement	To be determined

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
National Grid (MA)	Docket No. 09-39	Revenue Decoupling	The AG witness stated: "[t]he adoption of such a mechanism should serve to reduce the volatility of a company's revenues and earned ROE. A reduction in volatility reduces the riskiness of an enterprise. Under the presumption that the Commission does include a decoupling mechanism, I recommend a 25 basis point reduction in the authorized return on equity to reflect the reduction in risk.	Pending	To be determined
Delmarva Power and Light (MD)	Case No. 9093	Bill Stabilization Adjustment	"[T]he BSA reduces the risks faced by the Company, and thus allows us to reduce the return on equity by 50 basis points."	Final Order	ROE reduced 50 basis points
Potomac Electric Power Company (MD)	Case No. 9092	Bill Stabilization Adjustment	"[T]he BSA reduces the risks faced by the Company, and thus allows us to reduce the return on equity by 50 basis points."	Final Order	ROE reduced 50 basis points
Green Mountain Power (VT)	Docket No. 7175	Alternative Regulation Plan	"There is no question that GMP will shed substantial risk, which will now be passed on to ratepayers … The Company originally recommended an adjustment of 90 basis points … GMP and the Department now recommend a smaller, 50-basis-point adjustment." The Commission also stated, "Due to this uncertainty, it is not clear that the reduction of GMP's ROE by 50 basis points fully compensates ratepayers for the changes in risk.	Settlement	ROE reduced 50 basis points

Selected Examples of Proposed ROE Adjustments

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Cost of Capital Proposal	Case Decided	Outcome
FEDERAL					
Texas Eastern Transmission Corporation (FERC)	Docket No. CP87-312-008	Straight Fixed Variable	Texas Eastern challenges the Commission's decision to reduce the return on equity by 25 basis points. Texas Eastern submits that here the Commission failed to consider factors such as capital structure, service profile, competitive risks, operational risk, etc., in computing the appropriate return on equity. The Commission response explains that "[t]raditional MFV rate design places a pipeline's return on equity and the taxes related to that return, which are fixed costs, in the commodity component of rates. If service is not used at the level projected by the Commission, these fixed costs will not be recovered. Under a straight fixed-variable rate design, all fixed costs, including return and equity and related taxes, are included in the demand component of the rates. Thus, under an straight fixed-variable rate design the equity investor's assurance of recovery approaches that of a bondholder."		0.25 reduction to cost of equity
Columbia Gas Transmission Corporation; Columbia Gulf Transmission Company (FERC)	Docket Nos. RP91-161-011, RP92-3-000, RP90-108-016, RP91-82-008, and RS92-5-000, RP91-160-000, RP92-2-000, RP90-107-013, and RS92-6-000	Straight Fixed Variable	The Cities believe that the failure to adjust the return on equity as a result of the change of rate design raises an issue of material fact, and that on cross examination they would have demonstrated that consistent with the Commission's determination in Transco, the returns on equity must be reduced to reflect the reduction of risk which accompanies the shift in rate design from MFV to SFV. Cities cites for example, Transcontinental Gas Pipe Line Corp., 56 FERC P61,037 (1991) (Transco), contending that the Commission imposed a 25 basis point reduction in the approved return on equity to reflect the possibility of lower risk.		0.25 reduction to cost of equity
United Distribution Companies, Petitioner v. FERC, Respondent (U.S. Court of Appeals, D.C. Circuit)	No. 92-1485	Order 636 SFV Rate Design	"The PUCs argue that FERC should have reduced the pipelines' rate of return because the pipelines will be able to recover all of their fixed costs and return on investment through demand and reservation charges instead of facing the uncertainty of recovering a portion of their fixed costs and return through gas sales throughout the year. ...Specifically, the PUCs contend that FERC should have followed its decision in Transcontinental Gas Pipe Line Corp., ...and imposed a 25 basis point reduction in pipelines' return on equity to reflect the lower risk under SFV rate design. "		0.25 reduction to cost of equity

Piedmont Natural Gas Company
Residential Equipment Rebate Summary

	Initial (Maximum) Rebate Amount	Minimum Required Efficiency
Natural Gas Storage Tank Water Heater	$50	Energy Factor = 0.62
Natural Gas Tankless Water Heater	$250	Energy Factor = 0.82
Natural Gas Forced Air Furnace	$300	AFUE[1] = 90%

Note: [1] AFUE is Annual Fuel Utilization Efficiency.
Source: Piedmont Petition, Ex. B., p. 2.

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.

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.

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.

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.