DEMANDE DE RENSEIGNEMENTS N^O 1 DE SOCIÉTÉ EN COMMANDITE GAZ MÉTRO À L'ASSOCIATION DES CONSOMMATEURS INDUSTRIELS DE GAZ (ACIG)

Information Requests to Dr. Booth

Data Request No. 1:

a) Please identify each rate case for an investor-owned regulated electric utility, natural gas utility, combination electric and natural gas utility, or pipeline utility in which Dr. Booth has testified in the last five years.

b) Please provide Dr. Booth's recommended return on equity for each rate case identified in part (a).

c) Please provide the authorized return on equity for each rate case identified in part (a).

d) Please provide the capital structure authorized by each regulatory body by each regulatory body identified in part (c) for each regulated electric utility identified in part (a).

e) Please provide the prevailing yield on long-term Canada bonds at the time Dr. Booth submitted his recommended return on equity for each rate case identified in part (a).

Data Request No. 2:

a) Is Dr. Booth currently teaching any college-level finance (corporate finance, investments, banking, etc.) courses?

b) Has Dr. Booth taught any college-level finance (corporate finance, investments, banking, etc.) courses in the last five years?

c) If the answer to parts (a) and/or (b) is affirmative, please identify the subjects of such courses and provide the syllabus and a list of textbooks/readings used in each course identified.

Data Request No. 3:

Has Dr. Booth ever presented formal cost of capital seminars to professional groups such as such as CAMPUT or any provincial/federal regulatory commission? If so, please provide a syllabus, table of contents, slide presentation, and list of references used in those seminars.

Data Request No. 4:

Please provide copies and/or summaries of any peer-reviewed book, monograph or article authored or co-authored by Dr. Booth in the last five years dealing with the subject of finance and/or utility regulation.

Data Request No. 5:

Please provide Dr. Booth's schedules containing numbers/tables in MS Excel format, with all cells unlocked and formulae available.

Data Request No. 6:

Please confirm that Dr. Booth:

a) gave no weight to the Comparable Earnings method.
b) gave no weight to the DCF method
c) gave no weight to the Historical Risk Premium method
d) used the equity risk premium (CAPM) method exclusively to develop his recommended rate of return on common equity.
e) Relied almost exclusively on a small sample of Canadian utilities.

Data Request No. 7:
(Executive Summary page 2, lines 24-25, line 35)

a) Given Dr. Booth's estimate of 10% for the overall market return (see also page 54 line 17) and beta estimate of 0.45-0.55, please confirm that GMLP is approximately half as risk as the overall equity market.

b) Given the CAPM market return and beta estimates in (a), please confirm that the implied return for GMLP is 4.5% - 5.5%, that is, 10% times 0.45-0.55.

Data Request No. 8:
(Page 10, lines 15-22))

a) On what basis does Dr. Booth conclude that Canadian regulatory boards were content that ROE formula adjustments produced fair and reasonable ROESs? To the best of his knowledge, is he aware of any Canadian regulatory body that is in the process of, or has abandoned, or has reexamined the adequacy of such ROE formula adjustments? If so, please provide references to such activity.

b) Does Dr. Booth share the same content as regulators as to the fairness and reasonableness of ROEs produced by formula adjustments?

c) Given the recent changes and abandonment of ROE adjustment formulas by various Canadian regulators, please explain your comment on page 17 lines 1-3 that "there is an openness on the part of the AUC, the Regie and the Board of Commissioners of Newfoundland and Labrador to the idea of maintaining their existing ROE adjustment formula."

Data Request No. 9:
(Pages 11-12)

Please provide the entire CAMPUT 2008 slide presentation by Matt Akman of MacQuarie from which the slide shown on page 11 was drawn.

Data Request No. 10:
(Page 29 lines 4-5)

Given the recent downgrade of Ireland's and Greece's bonds, is it still Dr. Booth's opinion that "the worst of the European debt crisis seems to have passed…."

Data Request No. 11:
(Page 29 lines 4-5)

a) Given the very close parity between the Canadian and US dollars, is it still Dr. Booth's opinion that allowed returns for Canadian utilities cannot be compared with allowed returns in the U.S.?

b) Does Dr. Booth believe that Canadian investors do not make such allowed ROE comparisons given the increased degree of integration between the US and Canadian capital markets? Why, or why not?

Data Request No. 12:
(Page 34 footnote 15)

Please provide a copy of the Scotia Capital study cited in footnote 15.

Data Request No. 13:
(Page 38)

Please provide an updated copy of the Bloomberg screen capture shown on page 38 using current yield data.

Data Request No. 14:
(Page 41)

Please provide a copy of the Garcia and Yang study cited in footnote 20, page 41.

Data Request No. 15:
(Page 44)

a) Please provide a copy of the Graham and Harvey study cited on page 44.

b) Please confirm that this study was performed prior to the financial crisis of 2008-9.

c) Does Dr. Booth believe that the results of this study are still applicable and relevant given the repricing of risk following the financial crisis of 2008-2009?

Data Request No. 16:
(Graham & Harvey survey, Page 44)

a) Is Dr. Booth aware of another comprehensive study of financial practices published by Bruner "*Best Practices in Estimating the Cost of Capital: Survey and Synthesis*." If so, why did he not rely or cite this well-known study?

b) Please confirm that according to the comprehensive Bruner study (page 59) practitioners rely principally on beta estimates published by such sources as Bloomberg, Value Line, and Standard & Poor's

c) Please confirm that neither the Bruner survey or the Graham & Harvey study mention practitioners performing any kind of statistical adjustment for beta trends over time.

Data Request No. 17:
(Page 46 lines 20-22)

a) Please confirm that Dr. Morin does not adjust betas using the standard adjustment model due to Marshall Blume and adopted by groups like Value Line, Bloomberg, and Merril Lynch but rather relies on the betas published by the latter groups that are available to the investment community.

Data Request No. 18:
(Page 49 lines 5-7)

a) On page 49 lines 5-7, Dr. Booth states that the Canadian risk premium has consistently been lower than that in the US due in large part to the higher bond returns in Canada. Given that government bond yields are now lower in Canada, is it Dr. Booth's opinion that the Canadian risk premium is now higher than that in the US? Please explain.

b) Given his statement on page 49 that the Canadian risk premium has consistently been lower than that in the US due in large part to the higher bond returns in Canada, is Dr. Booth's statement on page 51 lines 14-15 that the US market risk premium exceeds by about 1.0% that of Canada still correct? If so, why? If not, why not?

Data Request No. 19:
(Page 54 line 26)

a) Please explain why Dr. Booth did not rely on the two-factor model on which he relied in 2009 in this case and to which he refers on page 73 lines 7-9?

b) Please produce the results of the same two-factor model used in 2009 in the current case.

Data Request No. 20:
(Pages 55-57 utility betas, page 56 graph)

a) Please provide a list of the utility companies used in the production of the graph on page 56.

b) Why did Dr. Booth not provide the same tabular data used for US utilities on page 60 for his sample of Canadian utilities?

c) Please provide in machine-readable form all the data employed in the production of the graph on page 56 in a similar tabular form to what you provided for US utilities on page 60.

d) Please provide the most current individual beta estimates for each of the utility companies employed in the production of the page 56 graph.

e) How are the betas shown on the graph computed, that is, over what period, using what market index, and what return period (monthly, daily, weekly, etc)?

f) Are the betas shown on the graph adjusted betas or raw betas?

g) Please provide the Value Line and Bloomberg betas for each Canadian utility company used in the sample of utility companies used in the production of the graph.

h) Please confirm that Dr. Booths has consistently used raw or unadjusted betas in his previous testimonies before Canadian regulatory boards. If not, please explain. Please provide literature references in support of the use of raw betas **by the investment community**.

Data Request No. 21:
(US utility betas, Page 60 graph)

a) Please provide in machine-readable form all the data employed in the production of the graph on page 60.

b) How are the betas shown on the page 60 graph computed, that is, over what period, using what market index, and what return period (monthly, daily, weekly, etc)?

c) Are the betas shown on the graph adjusted betas or raw betas?

d) Please provide the Value Line and Bloomberg betas for each of the seven US utility companies listed on page 60.

Data Request No. 22:

a) Please provide the currently authorized return on equity for the each of the utilities in your sample of Canadian utilities used in the production of the graph on page 56.

b) Please provide the currently authorized return on equity for the each of the utilities in your sample of US gas utilities used in the production of the graph on page 60.

Data Request No. 23:
(Beta estimates graphs, page 56, 57, 60)

a) Please confirm that Dr. Booth relied on a beta estimate of 0.45-0.55 with a midpoint of 0.50 in arriving at his recommended ROE.

b) Please confirm that according to the graph on page 56, the current beta for Canadian utilities is in the approximate range of 0.30 – 0.35.

c) Please confirm that according to the graph on page 57, the current beta for Canadian utilities is approximately 0.40.

d) Please confirm that according to the graph on page 60, the current beta for US gas utilities is approximately 0.35.

e) Given that the current beta estimates for Dr. Booth's sample utilities are in the 0.30-0.40 range, please provide a complete rational as to how Dr. Booth arrive at a beta of 0.45 - 0.55 for GMLP.

f) If unable to do so, please restate your CAPM results with a beta estimate of 0.30-0.40.

g) Please confirm that the AUC, BCUC, and Newfoundland relied on beta estimates of 0.50-0.63, 0.60-0.66 and 0.60, respectively as per page 48 line 16 of Dr. Booth's testimony.

Data Request No. 24:
(Beta estimates graphs, page 56, 57, 60)

a) Does Dr. Booth firmly believe that the investment community disregards the commercially available betas published by Value Line, Bloomberg, S&P and others on the grounds that they are adjusted betas. If so, why?

b) Does Dr. Booth firmly believe that Value Line, Bloomberg, S&P and others have been in error all these years in estimating adjusted betas, including utility betas? If so, how do you explain the wide commercial dissemination of such betas?

c) Does Dr. Booth firmly believe that the investment community actually performs corrective statistical surgery in order to "correct" the betas published by Value Line, Bloomberg, S&P and others on the grounds that they are adjusted betas rather than raw betas. If so, why?

d) Does Dr. Booth firmly believe that the investment community produces its own homemade raw betas in making investment decisions rather than relying on commercially available sources of published betas? If not, or if so, please explain.

Data Request No. 25:
(Market risk premium discussion, pages 48-55)

a) Please confirm that most, if not all, references to a market risk premium estimate on pages 48-55 of Dr. Booth's testimony are based on arithmetic mean returns and not on geometric mean returns. If the latter, please restate these estimates on the basis of arithmetic mean returns.

b) Please confirm that the well-known and widely-used finance textbook by Brealey, Myers, et. Al. Principles of Corporate Finance (Dr. Booth references the same authors on page 9 Appendix C) concludes that a reasonable range for the market risk premium is 5.0% - 8.5%.

Data Request No. 26:
(DCF Model Estimates, page 63)

a) Given that utility companies pay dividends on a quarterly basis, please explain why Dr. Booth relied on the annual version of the DCF model instead of relying on the quarterly version of the DCF model that he presents on pages 67-72.

b) Please provide a list of publicly traded companies on the Toronto Stock Exchange which pay dividends on a quarterly basis and a list of those companies that do not.

Data Request No. 27:
(Analysts Growth Forecasts, page 71 line 21, page 72 lines 8-9)

a) Please provide copies of, and citations, to any and all workpapers, textbooks, articles, or publications, including but not limited to any electronic workpapers, articles, or publications, relied upon by Dr. Booth that substantiate Dr. Booth's assertion that security analysts' earnings forecasts are overly optimistic.

b) Does this statement apply equally to utility companies as well as industrials? Please explain and substantiate.

c) Does Dr. Booth agree that independent research firms such as Value Line have no incentive to distort earnings growth estimates in order to bolster interest in common stocks.

Data Request No. 28:
(Page 4 lines 1-5)

a) Is it Dr. Booth's contention that risk-mitigating mechanisms such as the use of deferral accounts used by the Regie to combat risk are unique to the Company?

b) Which of the companies in Dr. Booth's two sample groups of Canadian and US utilities have rates set using future test years and which of those companies have rates set using historical test years?

c) Concerning Dr. Booth's two proxy groups of companies, indicate which companies possess a fuel/gas adjustment clause.

d) Concerning Dr. Booth's two proxy groups of companies, indicate which companies possess capital investment rider clauses.

e) Concerning Dr. Booth's two proxy groups of companies, indicate which companies possess revenue decoupling mechanisms.

f) Concerning Dr. Booth's two proxy groups of companies, indicate which companies possess performance-based incentive mechanisms.

g) Please confirm that the US gas utilities in Dr. Booth's sample of companies possess most, if not all, of the same or similar risk-mitigating mechanisms listed on page 21 (lines 10-19) of Dr. Booth's Appendix C.

h) Concerning your discussion of risk-mitigating mechanisms for US utilities, please comment on the following two reports: "The Impact of Decoupling on the Cost of Capital" from The Brattle Group (attached) and "Decoupling mechanisms/ straight-fixed-variable rate design" from Regulatory Research Associates (attached), analyzing the use and the impact of risk-mitigating mechanisms by US utilities.

Data Request No. 29:

a) Does Dr. Booth's recommended return assume the maintenance of SCGM's existing capital structure or does it assume Dr. Morin's recommended capital structure?

b) Does Dr. Booth's ROE recommendation assume a deemed common equity ratio of 38.5%? If not, please restate Dr. Booth's ROE recommendation assuming a deemed common equity ratio of 42.5%.

Data Request No. 30:

Please identify each Canadian or U.S. investor-owned regulated electric, gas, or pipeline utility, with a rate of return on common equity that is equal to, or less than your recommended return of 8.1.0%?

Data Request No. 31:

a) On page 84, Dr. Booth states that the typical bond rating in the US is BBB whereas it is "A" for Canadian utilities. Is Dr. Booth referring to both electric and gas utilities? If not, please provide the typical bond rating in the US for natural gas distribution utilities.

b) Please provide the bond ratings for the two samples of utilities used by Dr. Booth in deriving betas estimates.

c) Please confirm that Dr. Booth's sample of seven US gas utilities have a bond rating of "A".

Data Request No. 32:
(US vs. Canadian Utilities samples)

a) Please confirm that the percentage of regulated assets for your US sample of natural gas utilities exceeds that of your Canadian utility sample.

b) Please confirm that Gaz Metro is exposed to far more intense competition from electricity and fuel oil than the seven US natural gas utilities in your sample.

c) Please confirm that Gaz Metro's industrial load is far greater than for the seven US natural gas utilities in your sample.

d) Please confirm that natural gas penetration in Quebec is significantly less thae natural gas penetration in the franchises served by the seven US natural gas utilities in your sample.

e) Please confirm that Gaz Metro's performance incentive scheme exposes the company to volume risk to which none of the seven US natural gas utilities in your sample.

f) Please confirm that the allowed returns for you sample of Canadian utilities and Gaz Metro are significantly less than those allowed the seven US natural gas utilities in your sample.

g) Please confirm that the seven US natural gas utilities in your sample have much higher common equity ratio than Gaz Metro, and therefore less financial risk.

h) Given your responses in a) to g) above, is it still your position that "it is commonly accepted that us utilities are riskier than Canadian ones."

Data Request No. 33:
(US vs. Canadian yield differences page 89)

a) Please provide copies of, and citations, to any and all workpapers, articles, or publications (including but not limited to any electronic workpapers, articles, or publications) relied upon by Dr. Booth that substantiate Dr. Booth's assertion that there is a 0.50% difference between ong-term US treasury yields and LTC Canada yields.

b) Please provide the most recent forecasts of long-term US treasury yields and LTC Canada yields to substantiate that claim.

c) Please provide an estimate of the 2011 cost of long-term debt for SCGM given the 4.5% yield assumed on long-term government of Canada bonds in Dr. Booths' analysis.

Data Request No. 34:
(Recent regulatory decisions, page 8 line 12)

Please provide a full copy of Peter Kind's presentation made before NARUC.

Data Request No. 35:
(A better ROE formula, page 78 line 16-20)

Please confirm that the research to which Dr. Booth refers to is the research by Garcia and Yang which references can be found at footnote 20, p. 41.

Data Request No. 36:
(US estimates, page 86 line 21-28)

Please provide a copy of the FERC announcement made in November 2003.

DISCUSSION PAPER

February 2011

The Brattle Group

The Impact of Decoupling on the Cost of Capital

An Empirical Investigation

By Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown[1]

Contents

__The Brattle Group__ provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.

We have offices in Cambridge, Massachusetts; San Francisco, California; and Washington, DC. We also have offices in Brussels, London, and Madrid.

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Introduction

Revenue decoupling (or simply "decoupling") is a form of regulated ratemaking that separates cost recovery from changes in the volume of sales for a regulated utility. It originated as a policy response in the 1980s when utilities were first encouraged to develop energy efficiency (EE) programs, which can significantly reduce the consumption of regulated commodities, such as electricity, gas, or water.

Research into the costs and benefits of EE technologies has shown that the long-run savings significantly exceed the costs, and EE programs have the additional benefit of producing no harmful emissions. Recently, more states have begun to adopt long-term goals for EE and designated the utilities as the program administrators. Despite the programs being beneficial and cost effective to society, there is a significant disincentive for the utilities to actively pursue the EE programs unless they are accompanied by some type of revenue decoupling and incentives.

This disincentive begins with the fact that a large share of an electric, gas, or water utility's costs are fixed in the short run and do not vary with the amount of the commodity produced and delivered. Traditional cost-of-service ratemaking collects these "base" revenues largely through volumetric rates (i.e., per therm, kilowatt hour, or 100 cubic feet). A successful EE program will reduce the volume of sales and simultaneously reduce recovery of the fixed costs, which include the equity returns, so regulated utilities have what is called a "throughput disincentive" to carry out EE programs.

1 The authors wish to thank members of *The Brattle Group* who provided comments including Larry Kolbe, Hannes Pfeifenberger, Bente Villadsen, Dan Kiernan, and Jenny Palmer.

There are various forms of decoupling, but the basic idea is that if sales exceed forecast, the utility will refund to customers the over-recovery of fixed costs. If sales are less than forecast, the utility will be able add a charge to future rates to fully recover its fixed costs. This removes the throughput disincentive and therefore the conflict of interest for utility management. With decoupling in place, managers of regulated investor-owned utilities avoid one major hurdle to pursuing EE programs that are in the public interest and maintain their fiduciary duty to protect the interests of their shareholders.[2] However, a new hurdle has appeared in the form of a tangible regulatory risk of a lowered allowed return on equity (ROE) for utilities that implement decoupling.

In addition to management's conflict of interest in reducing sales volume, EE programs are likely to increase the variability of the utility's revenues because the effectiveness of the EE program adds another element of forecasting error into setting the revenue requirement. As decoupling policies become increasingly prevalent and important, some intervenors and commission staffs have argued that decoupling, by design, reduces the variability of revenues by decoupling cost recovery from sales volume, which, they argue, translates directly into reduced risk. Intervenors, therefore, have also argued that the regulated company's cost of capital be reduced because cost of capital is the payment to investors bearing business and financial risks.[3]

In the majority of decisions approving decoupling in the past, regulators did <u>not</u> explicitly conclude that decoupling reduces a utility's cost of capital. However, in a very visible minority, regulators did decrease the allowed ROE, with the reductions generally ranging from 10 to 50 basis points (bps) (100 bps = 1 percent). More ominously, intervenors in some gas, electric, and water utility rate cases have suggested that the decoupling impact on ROE should be as large as 250 to 300 bps.[4] After reviewing a number of decisions where reductions were imposed by the regulators, we find that the reductions, whether moderate or substantial, appear to be based on theoretical arguments without the support of empirical evidence demonstrating an actual relationship between decoupling and the cost of capital. To test this theory, we have completed the first empirical investigation, of which we are aware, on the hypothesis that decoupling lowers the cost of capital.

The findings of our analysis do <u>not</u> support the belief that utilities <u>with</u> decoupling have a lower cost of capital than utilities <u>without</u> decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was <u>higher</u> by a <u>small but statistically significant</u> amount.

2 There are three conditions that are likely to be necessary to ensure that a utility's management is enthusiastic about the effect of large-scale EE programs on their financial performance. The first is decoupling, as discussed in this paper, and the second is the timely and concurrent recovery of the direct EE costs. Although together these two conditions make the utility financially indifferent, they do not provide the utility with a strong reason to pursue energy efficiency. The third condition is a performance incentive, which gives the management a financial incentive and, when successful, positive news for shareholders. Although utilities operate under a regulatory bargain, investors value growth in earnings and wish to see some other real value when growth is being reduced by public policy directives.

3 See Chapter 20, Brealey, Myers and Allen, *Principles of Corporate Finance*, 9th edition, McGraw Hill Irwin, 2008.

4 For example, see pp. 19-20 of "Phase 1B Testimony of Terry L. Murray on behalf of the Division of Ratepayer Advocates on Return on Equity Adjustments" before the California Public Utilities Commission filed October 19, 2007, Docket No. I. 07-01-022.

Section 1 VOLUMETRIC RATES, DECOUPLING,[5] AND THE THROUGHPUT DISINCENTIVE

Under traditional ratemaking, regulated utilities collect their base revenues, including the return on capital they hope to earn, using a combination of fixed charges and volumetric rates. (Volumetric rates are in dollars per kilowatt-hour for electric utilities or dollars per therm for gas utilities. Revenues collected through volumetric rates vary with overall usage.[6]) Volumetric-based cost recovery does not follow the principle of basing rates on marginal cost because a large part of a utility's costs is fixed and does not vary with the level of output and sales. Traditionally, the fixed charges generate only a small proportion of total revenues and do not fully recover the fixed element of total costs. If actual sales are less than forecast sales used to set rates, the utility will not earn its allowed ROE.

Successful EE programs will reduce sales volume relative to what sales would have been without the EE program and perhaps relative to sales volumes in previous years. The effect of declining sales on the revenue requirement (as well as the effect of increases in prudent costs) will be addressed in the next general rate case; when base rates are reset based on actual sales, but the lost fixed cost recovery for the effect of past EE programs will remain. Even with revised volumetric rates in place as a result of a rate case (and taking into account the effect of EE programs), the throughput disincentive immediately comes back into effect, so that between general rate cases, any reduction in sales from EE programs results in a reduction in earned ROE. To counteract the effect of declining sales on earned ROE, the utility may be forced to file more frequent general rate cases, which are time consuming, expensive, and risky, and therefore not a desirable solution. Thus utilities with volumetric rates have a throughput disincentive to carry out more aggressive programs for their customers to reduce energy usage, lower their utility bills, and help meet climate change policy goals.

This tension is in contrast with the overall cost effectiveness of the EE programs from several other perspectives. It is regularly shown in filings that a wide variety of utility-administered EE programs are cost effective from society's point of view. Because of their cost effectiveness and emissions-reducing effects, a number of states have adopted formal EE resource standards or similar EE goals. A recent survey of electric utilities showed that ratepayer-funded EE expenditures increased by over 57 percent between 2007 and 2009.[7] It is evident that the issue of addressing the throughput disincentive is becoming increasingly important. Decoupling of one form or another has been approved for natural gas LDCs in about 28 states and is pending in four more.[8] Decoupling has also been approved for electric utilities in about 13 states and is pending in seven more.[9]

5 This study assesses two different ratemaking approaches and uses the term "decoupling" to include both: 1) decoupling with general revenue true-up mechanisms and 2) straight fixed-variable rates. A related form of decoupled ratemaking is a lost revenue adjustment mechanism (LRAM) that focuses specifically on the impacts of EE programs on base revenues. Some discussions of decoupling limit the term to just the first approach and some include all three. There is no agreement about which of the three is best. This paper is only interested in the cost of capital impacts, not the comparative merits of the three types of decoupling. We include the first two decoupling approaches because they have similar impacts in insulating revenues collected from changes in the commodity throughput, other than those driven by increased numbers of customers. As is generally true, the companies in our gas sample use only these two forms of decoupled ratemaking.

6 A small percentage of fixed costs are recovered through customer charges and are not part of the decoupling issue. Some fixed costs for large customers are recovered in demand charges and are much less affected by EE programs. Finally, fuel and purchased power are large, variable costs for electric and gas consumers, and are both independent of the throughput disincentive, because revenues and costs go up or down together and changes generally cancel each other out.

7 "Summary of Ratepayer Funded Electric Efficiency Impacts, Expenditures and Budgets," Based on CEE/IEE Industry Database, Updated IEE Brief, May 2010.

8 American Gas Association, *Innovative Rates, Non-Volumetric Rates and Tracking Mechanisms: Current List*, as of June 2010.

9 Institute for Energy Efficiency, *State Energy Efficiency Frameworks*, July 2010, p. 2-3; updated for adoption in AZ and moving NV to a different policy.

If energy efficiency is the goal, decoupling is a useful form of regulated ratemaking that separates, or decouples, the collection of base revenues from sales of the product, so that utility profits are not hurt from the reductions in sales (for example, caused by EE programs). Decoupling removes the throughput disincentive and aligns the interests of utility management with the public policy goal of EE, and reduces sales with the management goal of earning the allowed rate of return for investors.

Section 2 DECOUPLING AND THE COST OF CAPITAL

Decoupling was adopted for three electric utilities in California in the 1980s as an adjunct to EE policies and has continued ever since, except for a brief hiatus during restructuring after 1998. California utilities have never had their cost of capital explicitly reduced because of decoupling. However, as decoupling has grown in importance in recent years within other states, a substantial regulatory risk has also emerged in the form of the potential reduction in the allowed ROE.

To date, about one-fifth of regulatory decisions that we have reviewed related to decoupling for gas and electric utilities have concluded that decoupling does reduce a utility's cost of capital, and accordingly these decisions have reduced the allowed ROE. The reductions in allowed ROEs have ranged from 10 to 50 bps. However, in our review of these cases, we could not find any empirical evidence that supported a reduction of any particular magnitude. The other four-fifths of the decisions adopted decoupling without explicitly reducing the cost of capital. Since the subject has gained greater notoriety, regulatory risk may still resurface as an issue when those utilities litigate their cost of capital in future general rate cases. We have developed an approach to investigate whether any reduction in the allowed ROE is warranted, and if so how small or how large the reduction should be.

A utility's operating earnings (i.e., earnings before income taxes) are the difference between base revenues (non fuel) and the sum of all prudent costs, which include operations and maintenance (O&M), administrative and general (A&G), depreciation, and interest. There are several sources of variability in the base revenue stream that can also be eliminated by the decoupling mechanisms analyzed here. EE programs decrease revenues because they decrease sales. Other increases and/or decreases in base revenue are driven by changes in weather, business activity over the business cycle, the net number of new customers, and the number of delinquent bills. By design, decoupling eliminates or significantly weakens the linkage between revenues and the volume sold, independent of the source of variability.

Decoupling stabilizes revenues, but net income still varies. Although depreciation and interest expense are relatively stable, other costs can change quickly between rate cases. At times of rapid capital investment, such as the present for utilities that are facing significant environmental retrofits, depreciation and interest may also increase rapidly so that general rate cases are frequently required. O&M and A&G costs can rise more than revenue, but are reasonably predictable and do not vary as directly with sales as do revenues. Therefore, if decoupling stabilizes the revenue side of the earnings equation, does it stabilize operating earnings as well? This leads directly to the question: if decoupling reduces revenue variability largely independent of the cost situation, does risk go down at the same time? A more targeted question is whether decoupling reduces the non-diversifiable risk that determines the cost of capital in financial markets? The answer is <u>not</u> a simple "yes."

Not all risks or sources of variance in earnings affect the cost of capital equally, because investors can simply avoid certain risks. For example, extremes of weather, including extreme mildness, will cause variance in a single utility's revenues and is a risk factor for that utility's earnings. However, investors can assemble a portfolio of utility stocks from across the U.S. climate zones and mitigate the weather effects of individual stocks in the portfolio. For the portfolio of utility stocks, the effect of weather variations should largely cancel out, removing weather as a source of investment risk, and negating its effect on the cost of capital. Portfolio formation removes other such risks that can be minimized by diversification.

Non-diversifiable risks, also known as "business risks", are the risks that remain after diversification. They are the risks that drive a company's cost of capital because investors must bear them. The distinction between diversifiable risk and non-diversifiable business risk is important to recognize when evaluating the effect of decoupling, or other regulatory policy, on a company's cost of capital. Simply reducing total risk does not imply that the cost of capital has been reduced. The risk reduced must be part of a company's business risk to affect its cost of capital, so only reductions in business risk justify a reduction in a regulated company's allowed ROE. Thus, we believe that there is strong need to address the empirical question of whether the presumed decrease in risk from adoption of decoupling policy results in a measurable decrease in the cost of capital for regulated utilities.

Section 3 AN EMPIRICAL TEST OF THE EFFECT OF DECOUPLING ON THE COST OF CAPITAL

For the nearly five year study period from October 2005 to June 2010, we examined a sample of exchange-traded companies in the natural gas distribution sector for which estimates of the cost of capital were available. For these holding companies, we examined each of their regulated gas local distribution company (LDC) subsidiaries and identified whether and when each LDC had decoupled versus traditional volumetric rates. We then compared the estimated cost of capital across two mutually exclusive groups: regulated utilities with all or a large share of revenues collected under decoupled ratemaking versus regulated utilities with all or a large share of traditional volumetric rates.

During the study period, co-author Dr. Michael Vilbert and others at *The Brattle Group* participated in a number of rate proceedings where the cost of capital was estimated for a sample of regulated gas LDCs. Some of the LDCs examined in these proceedings had decoupled rates at the beginning, some did not, and some became decoupled during the period. Hence, the cost of capital estimates from these proceedings provide a natural experiment on the impact of decoupling on the cost of capital. The specifics of our study are described below.

Developing a Sample of Traded Natural Gas Holding Companies

Our analysis is based on a carefully selected sample of holding companies that were exclusively or primarily involved in the regulated natural gas distribution industry. Over the study period, *Brattle* expert witnesses submitted cost of capital testimony 18 separate times based on an evolving sample of six to 12 gas LDC holding companies. Across the 18 dates, over 170 estimates of the cost of capital were made and submitted into evidence, subject to scrutiny.

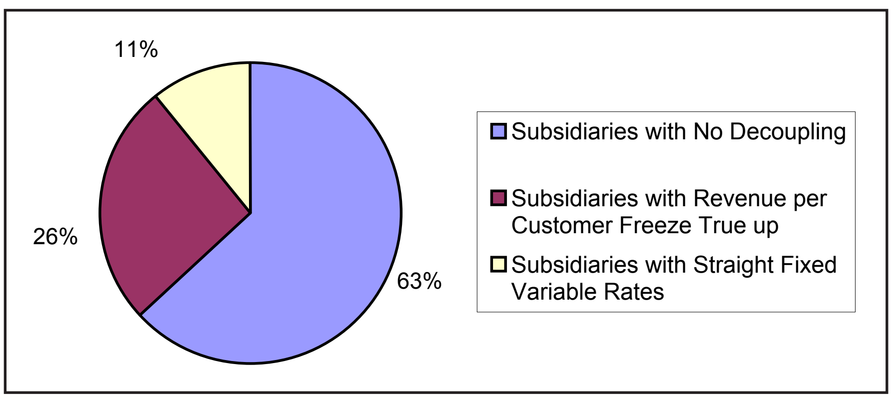
In each proceeding, *Brattle* selected a sample from the universe of all traded natural gas LDC holding companies followed by the investment advisory service, the *Value Line Investment Survey*, using six sample selection criteria that are designed to remove companies with characteristics that could bias the cost of capital estimates.[10] Over the study period, the selection criteria remained the same, but the composition of the sample changed slightly, (i.e., due to mergers). Thus, we have assembled a record of statistically valid estimates of the change in the cost of capital for every holding company in the sample for the study period.

Determining the Degree of Decoupling for Companies in the Sample

Holding companies, not their subsidiaries, have the market information necessary to estimate the cost of capital, because they have publicly traded stock. However, it is the individual state-regulated subsidiaries, not the holding companies themselves, that can be granted decoupled rates by state regulators. Hence, to characterize the degree of decoupling of each holding company, it is necessary to examine the decoupling policies of its subsidiaries in each state in which the subsidiary operates.[11]

To begin, we identified all regulated gas LDCs belonging to each holding company in the sample and then used a combination of primary and secondary sources to identify the subset of those gas LDCs that had decoupled rates during the study period. The 12 holding companies collectively held 46 regulated natural gas LDC subsidiaries as of June 2010. We used a broad definition of decoupling and included true-up decoupling schemes and straight fixed-variable (SFV) rates.[12] Figure 1 shows the distribution in June 2010 of true-up and SFV decoupling schemes among the 46 subsidiaries in our sample.

Figure 1 Shares of Decoupling Mechanisms in Natural Gas Sample in June 2010



10 The sample selection criteria are:

a. An investment grade credit rating, i.e., BBB- or better from S&P;

b. No dividend cuts during the last 5 years;

c. Revenues or assets > $300 million;

d. Greater than half of the assets in the regulated line of business, either natural gas distribution or regulated electric operations;

e. Data available from Value Line, Bloomberg and Moody's; and

f. No major mergers or acquisitions during the last 3 years

11 In this report, we use the term "subsidiary" to refer to the part of a utility that is regulated at the state level. A particular holding company might own two utilities that are separate corporations. Assume the first is located in a single state, while the second has a service territory extending over three states. In our analysis, this holding company would have four "subsidiaries".

12 See footnote 6. We did not find any gas LDC companies with decoupling in the form of a lost fixed revenue adjustment mechanism (LRAM), which is found frequently in electric utilities.

In our sample of 46 subsidiaries of 12 gas LDC holding companies, 37 percent had decoupling policies in place. We believe this is higher than the overall proportion of all LDCs in the population having decoupled rates. In total, we estimate there are approximately 49 LDCs across the country with decoupling,[13] out of an estimated population of over 300 LDCs,[14] implying that the proportion with decoupling is less than one-sixth, as shown below in Table 1.

Table 1 Natural Gas Decoupling Penetration

Natural Gas Delivery Utilities

Population and *Brattle* Sample of Regulated Subsidiaries: Total and Decoupled

	Gas LDC Subsidiaries	Number Decoupled	Share Decoupled
In Total Population	341	49	14%
In *Brattle* Sample	46	17	37%

Notes

The total row refers to all gas LDCs, counting them per state separately in which it delivered volumes of at least 5 bcf in 2008.

The sample row refers to 12 publicly-traded companies that meet *Brattle* criteria.

Not only does decoupling vary by subsidiary, but for some subsidiaries in our sample the status of decoupling has changed over time because state regulators have approved new mechanisms and, in some cases, changed or eliminated decoupling. To reflect this variation, we developed a robust decoupling index for each holding company over time. First, for each subsidiary, we made a specific designation of whether or not it was decoupled for each year in the sample period. Second, we aggregated the decoupling scores of the regulated subsidiaries to produce an overall decoupling score for the holding company. In this aggregation, we weighted all of the individual subsidiary scores (i.e., 1 or 0) based on their volume of gas distributed in 2008.

13 This is based on our examination of published reviews, for example, *Review of Distribution Revenue Decoupling Mechanisms*, Pacific Economics Group, March 2010, and *State Energy Efficiency Regulatory Frameworks*, Institute for Electric Efficiency, January 2010.

14 Based on EIA Form 176 data. In counting LDCs, such as in Figure 1, we exclude LDCs transporting less than 5 bcf per year. In estimating the index of decoupling for a holding company at points in time, we do not exclude any subsidiaries.

Table 2 below shows the decoupling index for each natural gas holding company in the sample at the end of the study period (June 2010).

Table 2 Decoupling Index for the Natural Gas Sample in June 2010

Company	Number of Gas LDC Subsidiaries	Decoupling Index
AGL	6	**0.82**
Atmos	12	**0.01**
Laclede	1	**1.00**
New Jersey Resources	1	**1.00**
Nicor	1	0.00
NiSource	9	**0.40**
Northwest Natural	3	**0.93**
Piedmont	3	**0.75**
South Jersey Industries	1	**1.00**
Southwest Gas	3	**0.68**
WGL	3	0.00
Vectren	3	**1.00**
Total	**46**	

Notes

Each subsidiary is counted once per state in which it operates.

The aggregate decoupling score for each group is the number of its gas LDC subsidiaries with decoupling multiplied by the 2008 gas volumes for those subsidiaries, divided by the total 2008 group gas volumes.

Estimating the Cost of Capital for Companies in the Sample

The cost of capital is defined as the return investors required in order to invest in an asset, or the expected return available on investments of comparable risk. There are a number of good and frequently used approaches for estimating the cost of capital for a company. One approach, though not used here, is to create estimates using historical data to estimate the parameters of a cost of capital model (e.g., estimate the Capital Asset Pricing Model (CAPM) beta using historical stock price returns). Another approach, which we do use here, is to compare current stock prices with forward-looking forecasts of cash flows from the business (e.g., one can use discounted cash flow (DCF) methods to compare the value of expected future dividends from the stock with current stock prices to estimate the expected returns). For this study, we used the DCF approach to estimate the cost of capital to analyze the effect of decoupling, because the DCF approach has the advantage of reflecting changes in the cost of capital more quickly than do other approaches that rely on the analysis of historical data.[15] In the DCF model, the discount rate that makes the present value of expected future dividends equal to the current stock price is the estimate of the cost of equity (COE) for the company.

15 For example, estimates of beta, the systematic risk parameter in the CAPM, are normally based upon 3 to 5 years of historical data. A policy that changed a company's cost of capital would lead to a change in the company's beta, but that change would not be fully reflected in the beta estimate for 3 to 5 years.

We chose to use a multi-stage version of the DCF model. In this version, security analysts' forecasts of company-specific future earnings were used for a five-year first stage of the multi-stage analysis to estimate expected dividends.[16] Later stages were added to ensure that the growth rate for each company eventually settled down to a single long-term growth rate based on the forecast of the long-term U.S. GDP growth rate. In particular, forecast growth rates for years 6 through 10 were linearly trended between company-specific earnings growth rates for the first 5 years and the long-term GDP growth rate in effect starting in year 11. Earnings growth was translated into corresponding expected dividend payments over time.

The COE is information of interest to regulators when they set the allowed ROE for a utility, so our focus is ultimately on whether there is a measurable reduction in the COE from the policy of decoupling. In general, the COE increases not only with increased business risk but also with increased financial risk.[17] Therefore, in testing for an impact on the cost of capital from decoupling, we systematically account for differences in the COE in different holding companies in the sample that arise from different levels of financial risk, which has nothing to do with decoupling.

To control for the effect of differences in capital structure (i.e., differences in financial risk) among the sample companies, we converted estimates of the COE into corresponding estimates of the overall after-tax weighted-average cost of capital (ATWACC).[18] The ATWACC measures the cost of capital for the business itself, while the COE estimate represents the cost of equity capital taking into account the equity-holders' additional financial risk from the company's level of debt financing. In other words, the ATWACC captures only the effect of business risk, while the COE is also affected by financial risk. For that reason, we use the ATWACC in our statistical analysis.

Statistical Analysis of Decoupling on the Cost of Capital

To determine the impact of decoupling on the cost of capital, we carried out the five statistical tests described below. The results of these tests were all in general agreement and collectively demonstrate that the overall impact in our data sample of the holding companies from decoupling of their rates was most likely a small increase, rather than a decrease, in their cost of capital. The estimated increases from the tests ranged from 6 to 42 bps. In some of the tests, the conclusion of an increase in cost of capital was statistically significant. In other tests, a small decrease cannot be ruled out, but even in those cases, it is far more likely that the rate increased rather than decreased. The estimated impacts and associated 95 percent confidence intervals for all five statistical tests can be seen in Figure 4. Our conclusion that decoupling most likely caused a small positive impact on cost of capital is shown in Figure 4 by noting that the bulk of the confidence interval in every case is above the zero "no effect" horizontal line.

16 We also implemented the test using the simple or constant growth DCF method. The results (not reported here) were not substantially different than those based upon the multi-stage DCF method.

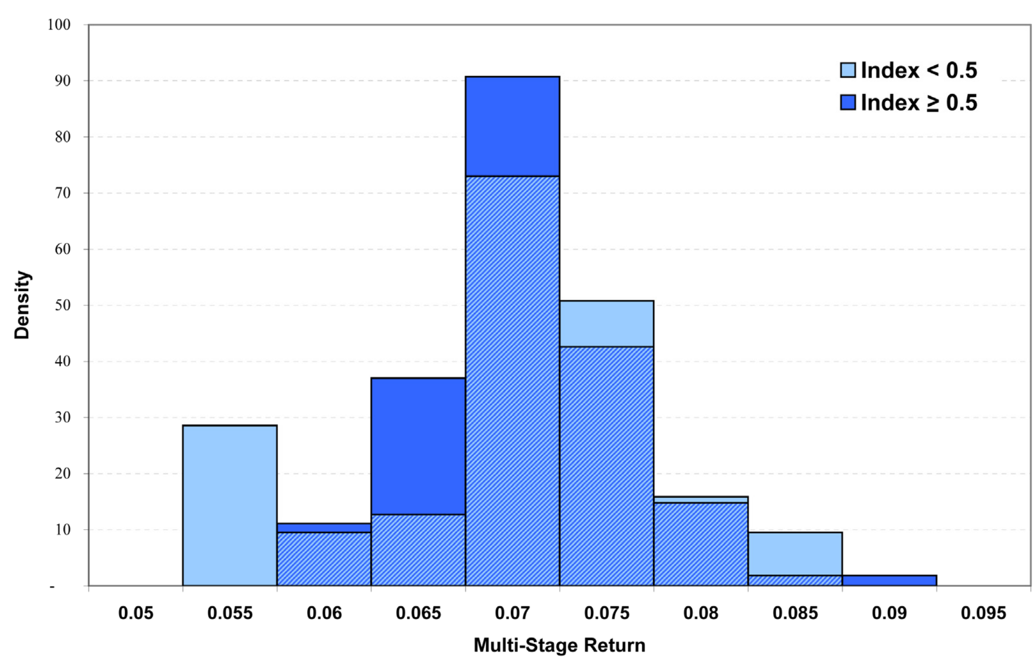
17 Financial risk is related to the degree to which the company's assets are debt financed. The greater the share of debt in the capital structure, the greater the interest that must be paid out of operating revenues before any shareholder earnings are available.

18 To be specific, the after-tax weighted-average cost of capital (ATWACC) is the measure we use. ATWACC is a weighted average of both the equity and debt returns after taking into account the tax deductibility of interest payments. The weights used in the calculation are the market values of debt and equity in the capital structure. See Chapter 20 of Brealey, Myers and Allen, op cit.

There were five statistical tests that we used. In the first test of the impact of decoupling on the cost of capital, we split the sample at each observation date into one of two groups: the group where the decoupling index (which can vary between 0 and 1) is below 0.5, and the remaining utilities in the group where the decoupling index is greater or equal to 0.5. We then compare the frequency distribution of the cost of capital estimates (specifically, the ATWACC calculated using a multistage DCF) for each group.

If the impact of decoupling on the cost of capital is large, we would expect the costs of capital estimates for the group with a high decoupling index to be noticeably lower than those with low decoupling index. Figure 2 displays the distribution of returns with a decoupling index of greater than 0.5 (dark blue) on top of the distribution of returns with a decoupling index of less than 0.5 (light blue). The cross hatch represents areas of overlap. We see that any impact of the differences in cost of capital from decoupling between the groups is smaller than the diversity in cost of capital within each group from other differences.

Figure 2 Distribution of Returns



The distribution of estimated cost of capital for holding companies that were highly decoupled (dark blue) and for holding companies that were not highly decoupled (lighter blue).

The first result is that the average cost of capital for the highly decoupled group was 7.313 percent, and the average cost of capital for the other group was 7.257 percent. Hence, we find that the more highly decoupled group of holding companies had a cost of capital that was slightly higher on average (5.6 bps) than the group with less decoupling. To examine the statistical significance of this first conclusion, we carried out a two-sample t test and found that the test gave a 95 percent confidence interval of the difference in average cost of capital between the groups that ranged from 17 bps lower up to 28 bps higher for the highly decoupled group. Therefore the observed difference in means is not statistically different from zero at this confidence level.[19] In other words, a t test on the two groups leads to an expectation that the drop in cost of capital from decoupling is highly likely to be less than 17 bps and is actually somewhat more likely to be positive than negative. The results of this first test raise the question of whether it is possible that companies with decoupling in place may actually have a higher cost of capital than companies without decoupling. The answer is that it is indeed possible, if investors view decoupled rates as a signal that the company faces some additional source of risk, then the cost of capital could actually increase if rates were decoupled.

As a hypothetical example, consider a utility whose sales volume was primarily driven by a highly diversifiable risk such as weather, and the other factors including EE impacts are assumed to be absent. In this example, there would be no material reduction in the cost of capital from the risk reduction due to decoupling. However, suppose that investors view the implementation of decoupled rates as an implication that the utility would be under increased regulatory scrutiny which could increase the possibility of disallowances, or that the decoupled rate program would limit the utility's ability to recover unanticipated costs outside of the decoupling program. In such a case, investors may see the decoupled rates as a sign that other risks could increase, and therefore the cost of capital could increase because of those risks. In other words, *a priori* we do not know whether decoupled rates will increase or decrease a utility's cost of capital — it is an empirical question that can be answered only through the kind of statistical analysis that we have done here.

Our first statistical test put a 95 percent confidence interval range on the estimated impact from decoupling on the cost of capital that is almost 50 bps wide. A natural next step is to see if there are patterns to the cost of capital data that can account for enough of the variability in returns in the subgroups to more tightly constrain the assessed limits on the decoupling impact.

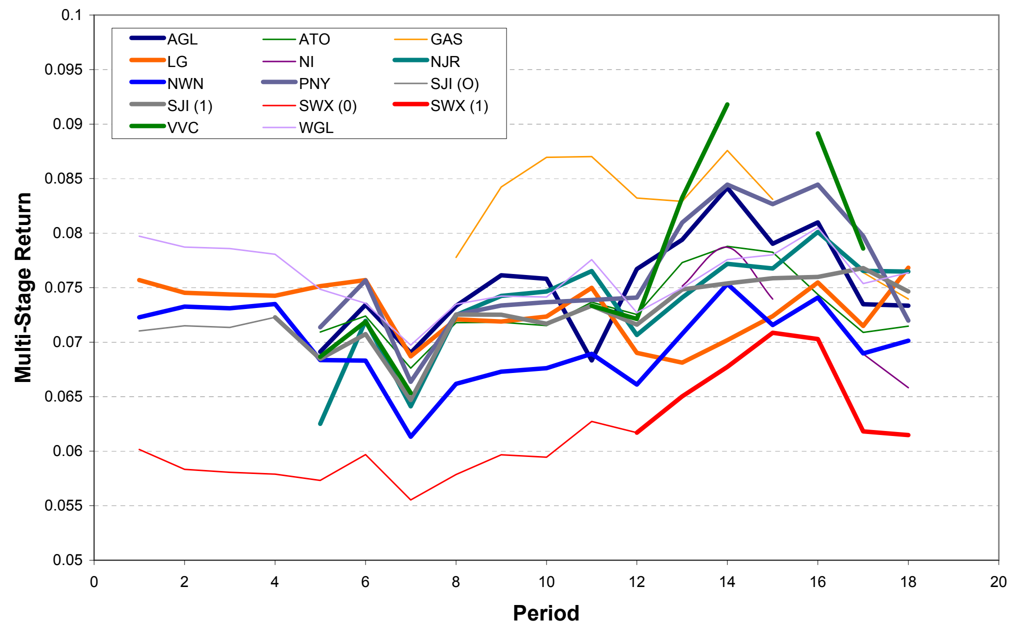
Figure 3 displays the cost of capital estimates by time period for each of the 12 holding companies in the sample and shows that the cost of capital estimates vary by time period and company. (In Figure 3, for each time series of cost of capital estimates for one holding company, the bold lines represent the exact periods in which the company's decoupling index was high, i.e., ≥ 0.5.) It is evident that there is a great deal of shared time variation[20] in the estimates, in addition to a great deal of company-specific variation. This observation serves to suggest additional statistical tests that should separate out the effects of shared time variation and company-specific variation in the statistical analysis.[21]

19 This confidence interval was from a t test based on the assumption that the sample variances of the two groups were equal. The assumption of equal variance makes the 95 percent confidence interval range slightly smaller but does not change the conclusion that the difference in means is not statistically significant.

20 Shared time variation is the variation in the ROE estimates that occur as a result of being done at different points in time.

21 The broken lines in Figure 3 are due to missing data for some estimation periods.

Figure 3 Cost of Capital Over Time



The estimated costs of capital by period for each holding company. (Bold lines represent periods in which the company's decoupling index was greater than or equal to 0.5.)

The four additional statistical tests were done using linear regression analyses. In all four additional tests, we accounted for shared time and company-specific variation through the use of time period- and company-specific indicator variables, which are common ways to isolate the impact of such factors from the impact of the quantity you are testing (here the level of decoupling). The use of these indicator variables accounted for over 80 percent of the variation in the estimated costs of capital in the data.[22] The four tests differ in how the decoupling index was treated and whether the prior value of the cost of capital was included in the regression. In two of the tests, the decoupling is represented as an indicator variable with a value of 1 if decoupling is ≥ 0.5 ("highly decoupled") and 0 if it is < 0.5. In the other two tests, decoupling is represented using the actual numerical value of the decoupling index. The use of the actual value of the decoupling index is to determine whether the cost of capital estimates vary even if decoupling affects a relatively small or large portion of the assets of the holding companies.

To summarize, the four additional tests consist of two regressions with decoupling, represented with an indicator variable, carried out both with and without the inclusion of the prior cost of capital. The other two regressions, with decoupling represented by the decoupling index, were carried out both with and without the inclusion of the prior cost of capital in the regression.

[22] Examination of the regression residuals with a normal quantile-quantile plot and carrying out a Jarque-Bera test did not indicate problems with either non-normality or heteroskedasticity. However, the regression residuals do show some degree of serial correlation so we used Newey-West adjusted standard errors when making inference regarding the statistical significance of the impact of decoupling on the cost of capital.

In the first regression analysis, adding an indicator for the decoupling index being at least 0.5 into the regression leads to an estimated increase of 36 bps in the cost of capital from being highly decoupled (with a Newey-West 95 percent confidence interval ranging from +16 to +55 bps). This result is consistent with the results of the initial t test, because both include the region from +16 to +28 bps in their 95 percent confidence interval range. The impact of being highly decoupled is greater than zero (with statistical significance at the 95 percent confidence level). In other words, we have been able to show that the cost of capital in our sample was higher for decoupled companies than for companies with volumetric rates by taking into account company-specific differences and the variation in the cost of capital over time.

In the second regression analysis, we estimated the impact of decoupling by using the decoupling index itself as an explanatory variable in the regression and by taking into account company-specific differences and the variation in the cost of capital over time. This test shows that the increase in the cost of capital is 40 bps for a fully decoupled company compared to one with no decoupling (0 decoupling index).[23]

For the third and fourth regression analyses, we re-ran the prior two regressions with the additional inclusion of the prior period's cost of capital. The prior period's cost of capital was included to directly address some serial correlation, which we had seen in regression residuals from the base regression of cost of capital on period and company. The two regressions differ by the representation of decoupling as either an index or as an indicator variable. We note that the time intervals between the data points were not of uniform length because the underlying cost of capital studies are done when they are needed for regulatory proceedings, not on any fixed schedule. We believe the results of these third and fourth regressions still provide reliable evidence.[24] Both when we included the indicator of the decoupling index being at least 0.5 into the regression and when we included the decoupling index itself into the regressions, we found that the 95 percent confidence interval[25] on the impact of decoupling contained the common region from +22 to +28 bps found in the prior three tests.

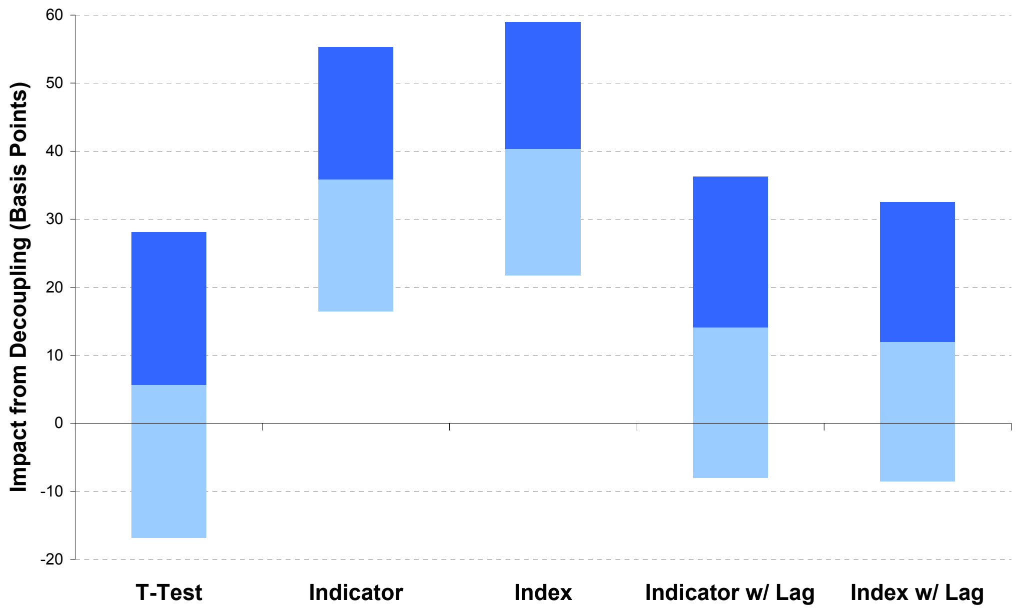
The results of the five tests provide what we consider to be strong evidence that the overall impact on companies' cost of capital following decoupling of their rates was more likely an increase than a decrease. The estimated impact and associated 95 percent confidence intervals for all five statistical tests can be seen in Figure 4.

23 The Newey-West 95 percent confidence interval ranges from +22 bps up to +59 bps. In this case, the positive result is statistically significant at the 95 percent confidence interval. This result remains consistent with the prior two tests, because they all contain the interval from +22 to +28 bps in their 95 percent confidence intervals.

24 We believe that the non-uniform periods of time are not an important issue in this analysis. Capital markets adjust to new information on a daily or even more frequent basis. The real issue is whether there were important changes between the observations to give them a degree of independence. Even to the casual observer, it is clear that the period from 2005 to 2010 was a period of change in U.S. financial markets, so the observations appear sufficiently independent to us.

25 For the regressions with the prior cost of capital included, "HC3" standard errors were used as described by Long and Ervin, Using "Heteroscedasticity Consistent Standard Errors in the Linear Regression Model," *The American Statistician*, 2000.

Figure 4 Summary of Estimated Impact on Cost of Capital



Comparison of the 95 percent confidence intervals demonstrating that decoupling may slightly increase the cost of capital and is highly unlikely to decrease the cost of capital by any material amount, based on our statistical tests.

Conclusion

Our statistical tests do not support the position that the cost of capital is reduced by adoption of decoupling. If decoupling decreases the cost of capital, these tests strongly suggest that the effect must be minimal because it is not detectible statistically.

As decoupling continues to grow in importance, cases will frequently come up where intervenors and commission staff may explore the extent to which decoupling reduces business risk and the utility's cost of capital. To date, in a minority of cases in which decoupling was approved, the utility explicitly had their allowed ROE reduced. Our research leads us to conclude that these reductions have been implemented with no empirical analysis to support the ROE reduction. The results of our analysis show that if such empirical analysis had been done, it is unlikely that it would have supported even the moderate reductions in allowed ROE that were imposed on the utilities.

Where decoupling is associated with implementing enhanced EE programs (as is almost always the case), adopting a reduction in allowed ROE in essence punishes a utility for pursuing EE programs. If a utility's management fears an unjustified reduction in the allowed ROE as a result of decoupling, the original disincentive to pursue EE programs is recreated in a new form, and the purpose of decoupling to align the interests of ratepayers, shareholders, and society as a whole may be frustrated.

To learn more about our expertise and our consulting staff, including our affiliated senior advisors, please visit www.brattle.com.

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RRA Topical Special Report April 5, 2011

DECOUPLING MECHANISMS/ STRAIGHT-FIXED-VARIABLE RATE DESIGN

~ A State-By-State Overview ~

A large part of today's "go-green" movement relies on energy conservation, something that can have troubling consequences for utility revenues and earnings. Generally accepted rate-setting practices create an inherent financial disincentive for utilities to participate in conservation programs, given that a successful energy usage reduction program would have a direct negative impact on utility revenues, and could impede a utility's ability to fully recover its fixed costs. Such a scenario could result in the utility filing a new general rate case in an attempt to recoup the related reduction in earnings. As environmental concerns have intensified, many states have adopted compulsory energy conservation standards; consequently, the need to mitigate the possible negative impacts of these programs has accelerated.

Decoupling mechanisms and, alternatively, straight-fixed-variable (SFV) rate designs, are now being used in many jurisdictions to ameliorate these disincentives, so that utilities may invest in the mandated conservation programs without the associated potential negative effect on earnings. In our view, utilities that are involved in rate cases on a frequent basis, e.g., annually, may have less of a need for a decoupling mechanism, as the rates reset in each rate proceeding should reflect any sales reductions caused by energy efficiency.

Additionally, we note that the issue of decoupling is addressed in the federal stimulus bill that became law in February 2009. The stimulus bill provides roughly $3 billion in state energy grants, and the Department of Energy has the authority to allocate these funds to the states, so long as the governor has been assured that the utility commission in that state will implement regulatory policies that align utility financial incentives with the successful implementation of energy efficiency measures.

Decoupling Defined

"Decoupling," as it applies to utilities, is defined as breaking the traditional link between a company's rates (i.e., revenues) and earnings. We'll use gas utilities as an example to show how decoupling is applied. Utility rates are generally comprised of two distinct buckets: (1) the commodity, or natural gas, rate bucket; and, (2) the distribution rate bucket. In order to understand the need for a decoupling mechanism, we need to review what happens to a utility's revenues when a customer "goes green" and cuts back on energy consumption.

Commodity charges are inherently usage sensitive, meaning that a customer will pay for the amount of gas consumed, no more and no less, and the utility does not earn a return or collect any margin on the commodity portion of the bill. Therefore, the utility's commodity revenues and costs will vary in tandem, and variations in customer usage will not impact the utility's bottom line. The distribution bucket, on the other hand, is comprised generally of both a monthly fixed charge and a volumetric (per BCF) charge; however, generally speaking, the actual costs associated with distribution service are predominantly fixed, meaning that the utility's distribution costs may not vary as customers' consumption patterns change.

For most companies, the customer's monthly bill contains a relatively small fixed monthly charge, and most of the bill is derived from a volumetric charge based on the amount of gas consumed during the month by each customer. Consequently, not all fixed costs are recovered through the fixed charge; a portion is recovered through the volumetric charge. Therefore, the problem for utilities with respect to a successful conservation program is that, as customers consume less natural gas, they avoid the related volumetric charges, which not only includes variable costs, but also some fixed costs. So, under this scenario, while the customer's bill is going down, the utility's cost of providing service is not falling to the same extent, and the utility fails to recover all of its costs.

Application of Decoupling

The utility's dilemma can be ameliorated in two ways: (1) employing a decoupling mechanism; or, (2) implementing an SFV rate design. A decoupling mechanism essentially allows the utility to defer fixed distribution costs that the utility fails to recoup through its volumetric charges due to customers' participation in conservation programs. The utility is then allowed to recover the deferrals associated with the unrecovered fixed costs through a surcharge mechanism over a period of time, generally with carrying charges on the deferred amounts. The pitfall of decoupling is that even though customers consume less natural gas, they may experience a decoupling-related, after-the-fact, surcharge -- not what customers expect after making a concerted effort to reduce usage. On the other hand, if the conservation programs are unsuccessful, there may be greater-than-expected gas consumption. In this scenario, the company would be required to defer any related over-recovery and the customers would ultimately experience a rate credit.

An alternative to decoupling is an "SFV" rate design. With SFV, a company's fixed costs are fully collected through the customers' fixed monthly charge. Therefore, no matter how successful a company's conservation program is, the utility's fixed costs will always be recovered. The only volumetric charge would essentially be the commodity charge. Therefore, by cutting back gas consumption, the customer would save only on the commodity portion of the monthly bill. And, since these costs are also avoidable by the utility, earnings would not suffer. In addition, from a public policy standpoint, SFV establishes a direct cause-and-effect relationship between usage and customer bill levels, and is easier to administer than a decoupling mechanism. However, a flash cut to an SFV rate design is difficult to accomplish because, as in our example, residential distribution customer rate designs tend to include relatively low fixed charges, and therefore a shift to a fully fixed rate would likely result in significant rate increases for the residential customers who are among the smallest gas consumers in this class.

We note that decoupling can vary widely in its application. Decoupling is commonly applied to offset the effect on earnings of unexpected sales reductions caused by energy efficiency mechanisms; however, some companies utilize decoupling mechanisms that cover more than just energy efficiency. A weather normalization clause (WNC) covers variations in sales caused only by weather, as measured by temperature, that varies from what is considered to be "normal." And, some decoupling mechanisms cover any variation in sales, whether the variation is caused by energy efficiency, weather, or the economy.

State-by-State Summary

As indicated in the accompanying table and footnotes, electric rate decoupling is in use in 19 states nationwide, while decoupling in the gas industry is in use in 29 states. Full SFV rate design is in place for at least one gas company in each of these four states -- Georgia, Missouri, North Dakota, and Ohio. We note that in the majority of gas rate cases decided in the past couple of years, the utilities' fixed monthly charges were increased by a greater percentage than the overall rate increase that was authorized. While this rate design change is intended to at least partly address the fixed charge recovery issues that flow from sales reductions, we have not included these instances in the accompanying table.

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Taylor Allred
Jim Davis
Russell Ernst
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Lisa Fontanella
Dennis Sperduto

Use of decoupling mechanisms/straight-fixed variable rate design at the state level (as of March 31, 2011)

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
ALABAMA				
Alabama Power	SO	Elec.	--	--
Alabama Gas	EGN	Gas	Weather	--
Mobile Gas	SRE	Gas	Weather	--
ARIZONA--#				
ARKANSAS--#				
Arkansas Western Gas	--	Gas	Full	--
Arkansas Oklahoma Gas	--	Gas	Full	--
CenterPoint Energy Resources	CNP	Gas	Full	--
Entergy Arkansas	ETR	Elec.	--	--
Oklahoma G & E	OKE	Elec.	--	--
Southwestern Electric Power	AEP	Elec.	--	--
CALIFORNIA--#				
California Pacific Electric	AQN/EMA	Elec.	--	--
Pacific Gas & Electric	PCG	Elec./Gas	Full	--
San Diego Gas & Elec.	SRE	Elec./Gas	Full	--
Southern California Edison	EIX	Elec.	Full	--
Southern California Gas	SRE	Gas	Full	--
Southwest Gas	SWX	Gas	Full	--
COLORADO--#				
Black Hills Colorado Electric	BKH	Elec.	--	--
Public Service Co. of Colorado	XEL	Elec.	--	--
"	"	Gas	Energy Effic.(P)	--
SourceGas Distribution	--	Gas	--	--
CONNECTICUT--#				
Connecticut Lt. & Pwr.	NU	Elec.	--	--
Conn. Natural Gas	IBE	Gas	--	--
Southern Conn. Gas	IBE	Gas	--	--
United Illuminating	UIL	Elec.	Full (P)	--
Yankee Gas Service	NU	Gas	--	--
DELAWARE--#				
DISTRICT OF COLUMBIA--#				
Potomac Electric Power	POM	Elec.	Full	--
Washington Gas Light	WGL	Gas	--	--
FLORIDA--#				
GEORGIA--#				
Atlanta Gas Light	AGL	Gas	--	✓
Atmos Energy	ATO	Gas	--	--
Georgia Power	SO	Elec.	--	--
HAWAII--#				
Hawaiian Electric	HE	Elec.	Full	--
Hawaii Electric Light	HE	Elec.	--	--
Maui Electric	HE	Elec.	--	--
IDAHO--#				
Avista Corp.	AVA	Elec./Gas	--	--
Idaho Power	IDA	Elec.	Energy Effic.(P)	--
PacifiCorp	BRK	Elec.	--	--
ILLINOIS--#				
Ameren Illinois	AEE	Elec./Gas	--	--
Commonwealth Edison	EXC	Elec.	--	--
Mid-American Energy	BRK	Elec./Gas	--	--
North Shore Gas	TEG	Gas	Full (P)	--
Northern Illinois Gas	GAS	Gas	--	--
Peoples Gas Light & Coke	TEG	Gas	Full (P)	--
INDIANA--#				
Duke Energy Indiana	DUK	Elec.	--	--
Indiana Gas	VVC	Gas	Energy Eff./Weather	--
Indiana Michigan Power	AEP	Elec.	--	--
Indianapolis Power & Light	AES	Elec.	--	--
Northern Indiana Public Service	NI	Elec./Gas	--	--
Southern Indiana Gas & Electric	VVC	Elec.	--	--
"	"	Gas	Energy Eff./Weather	--
IOWA--n.a.				
KANSAS--#				
Atmos Energy	ATO	Gas	--	--
Black Hills/Kansas Gas Utility	BKH	Gas	Weather	--
Empire District Electric	EDE	Elec.	--	--
Kansas City Power & Light	GXP	Elec.	--	--
Kansas Gas & Electric	WR	Elec.	Energy Effic.	--
Kansas Gas Service	OKE	Gas	Weather	--
Westar Energy	WR	Elec.	Energy Effic.	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
KENTUCKY--#				
Atmos Energy	ATO	Gas	Energy Eff./Weather	--
Columbia Gas of Kentucky	NI	Gas	Energy Eff./Weather	--
Delta Natural Gas	DGAS	Gas	Energy Eff./Weather	--
Duke Energy Kentucky	DUK	Elec.	Energy Effic.	--
"	"	Gas	Energy Effic.	--
Kentucky Power	AEP	Elec.	Energy Effic.	--
Kentucky Utilities	PPL	Elec.	Energy Effic.	--
Louisville Gas & Electric	PPL	Elec.	Energy Effic.	--
"	"	Gas	Energy Eff./Weather	--
LOUISIANA--#				
Atmos Energy	ATO	Gas	Weather	--
CenterPoint Energy Resources	CNP	Gas	Weather	--
Cleco Power	CNL	Elec.	--	--
Entergy Gulf States	ETR		--	--
Entergy Louisiana	ETR	Elec.	--	--
Entergy New Orleans	ETR	Elec./Gas	--	--
Southwestern Electric Power	AEP	Elec.	--	--
MAINE--#				
MARYLAND--#				
Baltimore Gas & Electric	CEG	Elec./Gas	Full	--
Columbia Gas of Maryland	NI	Gas	Weather	--
Delmarva Power & Light	POM	Elec.	Full	--
Potomac Edison	FE	Elec.	--	--
Potomac Electric Power	POM	Elec.	Full	--
Washington Gas Light	WGL	Gas	Weather	--
MASSACHUSETTS--#				
Boston/Colonial/Essex Gas	NGG	Gas	Full	--
Columbia Gas of Massachusetts	NI	Gas	Full	--
Fitchburg Gas & Electric	UTL	Elec./Gas	--	--
Massachusetts Electric	NGG	Elec.	Full	--
New England Gas	SUG	Gas	Full	--
NSTAR Electric	NST	Elec.	--	--
NSTAR Gas	NST	Gas	--	--
Western Mass. Electric	NU	Elec.	Full	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
MICHIGAN--#				
Consumers Energy	CMS	Elec.	Full (P)	--
"	"	Gas	Energy Effic.(P)	--
Detroit Edison	DTE	Elec.	Full (P)	--
Indiana Michigan Power	AEP	Elec.	--	--
Michigan Consolidated Gas	DTE	Gas	Energy Effic.(P)	--
Michigan Gas Utilities	TEG	Gas	Energy Effic.(P)	--
SEMCO Energy Gas	--	Gas	--	--
Upper Peninsula Power	TEG	Elec.	Full (P)	--
Wisconsin Electric Power	WEC	Elec.	--	--
MINNESOTA--#				
Allete Minnesota Power	ALE	Elec.	--	--
CenterPoint Energy Resources	CNP	Gas	Energy Effic.(P)	--
Interstate Power & Light	LNT	Elec.	--	--
Minnesota Energy Resources	TEG	Gas	--	--
Northern States Power-Minnesota	XEL	Elec.	--	--
"	"	Gas	--	
Otter Tail Power	OTTR	Elec.	--	--
MISSISSIPPI--n.a.				
MISSOURI--#				
Atmos Energy	ATO	Gas	--	--
Empire District Electric	EDE	Elec.	--	--
Empire District Gas	EDE	Gas	--	--
Kansas City Power & Light	GXP	Elec.	--	--
KCP&L Greater Missouri Operations	GXP	Elec.	--	--
Laclede Gas	LG	Gas	--	--
Southern Union	SUG	Gas	--	✓
Union Electric	AEE	Elec.	--	--
MONTANA--#				
MDU Resources	MDU	Gas	Energy Effic.	--
Northwestern Energy	NWEC	Elec.	Energy Effic.(P)	--
"	"	Gas	--	--
NEBRASKA--#				
Black Hills Nebraska Gas	BKH	Gas	--	--
Northwestern Energy	NWEC	Gas	--	--
SourceGas Distribution	--	Gas	--	--
NEVADA				
Nevada Power	SRP	Elec.	Energy Effic.	--
Sierra Pacific Power	SRP	Elec./Gas	Energy Effic.	--
Southwest Gas	SWX	Gas	Full	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
NEW HAMPSHIRE--#				
NEW JERSEY--#				
Atlantic City Electric	POM	Elec.	--	--
Jersey Central Power & Light	FE	Elec.	--	--
New Jersey Natural Gas	NJR	Gas	Full (P)	--
Pivotal Utility Holdings	AGL	Gas	Weather	--
Public Service Electric & Gas	PEG	Elec.	--	--
"	"	Gas	Weather	--
Rockland Electric	ED	Elec.	--	--
South Jersey Gas	SJI	Gas	Full (P)	--
NEW MEXICO--#				
NEW YORK				
Brooklyn Union Gas		Gas	Full	--
Central Hudson as & Electric	CHG	Elec./Gas	Full	--
Consolidated Edison of New York	ED	Elec./Gas	Full	--
KeySpan Gas East	NGG	Gas	Full	--
National Fuel Gas Distribution		Gas	Full	--
New York State Electric & Gas	IBE	Elec./Gas	Full	--
Niagara Mohawk Power	NGG	Elec./Gas	Full	--
Orange & Rockland Electric	ED	Elec./Gas	Full	--
Rochester Gas & Electric	IBE	Elec./Gas	Full	--
NORTH CAROLINA--#				
Carolina Power & Light	PGN	Elec.	--	--
Duke Energy Carolinas	DUK	Elec.	--	--
Piedmont Natural Gas	PNY	Gas	Full	--
Public Service Co. of North Carolina	SCG	Gas	Full	--
Virginia Electric & Power	D	Elec.	--	--
NORTH DAKOTA--#				
MDU Resources	MDU	Elec./Gas	--	--
Northern States Power-Minnesota	XEL	Elec.	--	--
"	"	Gas	--	✓
Otter Tail Power	OTTR	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
OHIO--#				
Cleveland Electric Illuminating	FE	Elec.	Energy Effic.	--
Columbia Gas	NI	Gas	--	✓
Columbus Southern Power	AEP	Elec.	Energy Effic.	--
Dayton Power & Light	DPL	Elec.	Energy Effic.	--
Duke Energy Ohio	DUK	Elec.	Energy Effic.	
"	"	Gas	--	✓
East Ohio Gas	D	Gas	--	✓
Ohio Edison	FE	Elec.	Energy Effic.	--
Ohio Power	AEP	Elec.	Energy Effic.	
Toledo Edison	FE	Elec.	Energy Effic.	--
Vectren Energy Delivery of Ohio	VVC	Gas	--	✓
OKLAHOMA--#				
CenterPoint Energy Resources	CNP	Gas	Weather	--
Oklahoma Gas & Electric	OGE	Elec.	Energy Effic.	--
ONEOK	OKE	Gas	--	--
Public Service Oklahoma	AEP	Elec.	--	--
OREGON--#				
Avista Corp.	AVA	Gas	--	--
Idaho Power	IDA	Elec.	--	--
Northwest Natural Gas	NWN	Gas	Energy Eff./Weather (P)	--
PacifiCorp	BRK	Elec.	--	--
Portland General Electric	POR	Elec.	Energy Effic.	--
PENNSYLVANIA--#				
RHODE ISLAND--#				
Narragansett Electric	NGG	Elec.	--	--
"	"	Gas	Weather	--
SOUTH CAROLINA--#				
Carolina Power & Light	PGN	Elec.	--	--
Duke Energy Carolinas	DUK	Elec.	--	--
Piedmont Natural Gas	PNY	Gas	Weather	--
South Carolina Electric & Gas	SCG	Electric	Weather (P)	--
"	"	Gas	Weather	--
SOUTH DAKOTA--n.a.				
TENNESSEE--#				
Atmos Energy	ATO	Gas	--	--
Chattanooga Gas	AGL	Gas	Full (P)	--
Kingsport Power	AEP	Elec.	--	--
Piedmont Gas	PNY	Gas	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
TEXAS PUC--n.a.				
TEXAS RRC--#				
Atmos Energy	ATO	Gas	Weather	--
CenterPoint Energy Resources	CNP	Gas	--	--
Texas Gas Service	OKE	Gas	Weather	--
UTAH--#				
PacifiCorp	BRK	Elec.	--	--
Questar	STR	Gas	Energy Eff./Weather	--
VERMONT--#				
VIRGINIA--#				
Appalachian Power	AEP	Elec.	--	--
Columbia Gas of Virginia	NI	Gas	Energy Eff./Weather	--
Kentucky Utilities	PPL	Gas	--	--
Virginia Electric & Power	D	Elec.	--	--
Virginia Natural Gas	AGL	Gas	Energy Eff./Weather	--
Washington Gas Light	WGL	Gas	Energy Eff./Weather	--
WASHINGTON--#				
Avista Corp.	AVA	Elec.	--	--
"	"	Gas	Energy Effic.	--
Cascade Natural Gas	MDU	Gas	--	--
Northwest Natural Gas	NWN	Gas	--	--
PacifiCorp	BRK	Elec.	--	--
Puget Sound Energy	--	Elec./Gas	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Decoupling	SFV
WEST VIRGINIA--#				
WISCONSIN--#				
Madison Gas & Electric	MGEE	Elec./Gas	--	--
Northern States Power-Wisconsin	XEL	Elec./Gas	--	--
Wisconsin Electric Power	WEC	Elec./Gas	--	--
Wisconsin Gas	WEC	Gas	--	--
Wisconsin Power & Light	LNT	Elec./Gas	--	--
Wisconsin Public Service	TEG	Elec./Gas	Full (P)	--
WYOMING--#				
Cheyenne Light Fuel & Power	BKH	Elec./Gas	--	--
MDU Resources	MDU	Elec.	--	--
PacifiCorp	BRK	Elec.	--	--
SourceGas Distribution	--	Gas	Energy Effic.	--

- Further detail is included in the Footnotes section.
(P) - Pilot program is in place.

FOOTNOTES

Arizona--On Dec. 15, the Arizona Corporation Commission (ACC) issued a policy statement regarding utility disincentives to energy efficiency. The ACC concluded that decoupling should be addressed through rate cases, with an evaluation to occur within three years. Decoupling has yet to be approved for any electric or gas utility in Arizona. The ACC had issued a Notice of Inquiry into the possible use of decoupling mechanisms as a means to encourage electric and gas utilities to promote the use of energy efficiency programs (the ACC's goal is to achieve a 22% reduction in KWH sales by year-end 2020). The ACC indicated, "revenue decoupling may offer significant advantages over alternative mechanisms, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests." The ACC concluded that non-fuel revenue per customer decoupling is appropriate, as it "is better suited to address the issues associated with customer growth." The Commission noted that decoupling should not be addressed through a pilot program, as this may be insufficient to support companies' demand side management efforts and is unlikely to lead to financial ratings improvements.

The Commission "recognizes that Arizona's largest utilities, while improving, are not well rated by financial rating agencies. The Commission believes it is important to send long-term signals and demonstrate commitment to decoupling before taking action on costs of capital" to reflect any modified risk levels. The ACC also concluded that "full decoupling is preferable to partial decoupling as it contributes to greater rate stability which would encourage improvements in financial ratings."

Arkansas--In December 2010, the Arkansas PSC approved a general framework to allow the state's electric and gas utilities to recover the "cost contribution to fixed costs" associated with energy-efficiency-related usage reductions. Arkansas Western Gas (AWG), Arkansas Oklahoma Gas (AOG), and CenterPoint Energy Resources (CER) currently utilize decoupling mechanisms, called "trial billing determinant rate adjustment" (BDA) riders, to mitigate the impact on the companies' revenues of reduced customer gas usage associated with conservation programs and economic-induced usage reductions. Separate weather normalization mechanisms are also in place for AWG, AOG, and CER.

California--Many of the state's electric and gas utilities operate under revenue adjustment (decoupling) mechanisms that modify rates annually to reflect changes, from any cause, in KWH sales and throughput from levels utilized to establish the revenue requirement.

Colorado--In July 2007, the Colorado PUC approved a pilot residential revenue decoupling mechanism, under which Public Service of Colorado is to absorb the lost revenue associated with the first 1.3% reduction in gas sales each year. The mechanism is to be in effect on a pilot basis from Oct. 1, 2008 through Sept. 30, 2011. Weather normalization is not part of this decoupling mechanism.

Connecticut-- As part of a July 17, 2009 rate case decision, the Connecticut DPUC abolished Southern Connecticut Gas' (SCG) weather normalization adjustment (WNA) that had been established in 1993. The state's other gas utilities, Yankee Gas Services and Connecticut Natural Gas (CNG), have never operated under a WNA.

State law allows the Connecticut Department of Public Utility Control (DPUC) to implement a mechanism designed to decouple electric and gas distribution revenues from sales volumes. Such decoupling may be accomplished through: a mechanism that adjusts actual distribution revenues to reflect allowed revenues; a sales adjustment clause; or, rate design changes that increase the amount of revenue recovered through fixed distribution charges. The law specifies that the DPUC must consider the impact of decoupling on the gas or electric distribution company's return on equity and make necessary adjustments thereto.

In 2007, the DPUC denied United Illuminating's (UI's) request to open a generic proceeding to implement electric and gas decoupling, stating that the legislative intent of the decoupling measure was to adopt mechanisms that were company-specific. As part of a 2009 electric rate decision for UI, the DPUC adopted a decoupling mechanism on a two-year pilot basis. The Department is in the process of evaluating the decoupling mechanism to determine whether to end, modify or continue the mechanism beyond its two-year trial period. In 2009 gas rate decisions for SCG and CNG, the DPUC declined to adopt decoupling mechanisms. Instead, the Department implemented certain rate design changes (increases to fixed charges) to satisfy the intent of the law. Similarly, in 2008 and 2010 electric rate decisions for Connecticut light & Power, the DPUC declined to adopt a decoupling mechanism, stating in the latter case that "it is reasonable to maintain decoupling...through rate design."

Delaware--In 2008, in a generic proceeding, the Delaware PSC: determined that implementation of surcharge mechanisms to reflect the costs/benefits of energy efficiency programs, including the associated revenue impact of the programs "are not the preferred approach, but that the Commission will not preclude the potential use of surcharges in the future under appropriate conditions"; and, opined that adoption of a "modified" fixed variable rate design would be a viable alternative for addressing the revenue impacts of energy efficiency/conservation measures. Implementation of such mechanisms for both the electric and gas operations of Pepco Holdings subsidiary Delmarva Power & Light is being addressed in pending cases.

District of Columbia--In September 28, 2009, the District of Columbia PSC approved the implementation of a Bill Stabilization Adjustment (BSA) for Pepco Holdings subsidiary Potomac Electric Power. In so doing, the PSC lowered Pepco's authorized equity return by 50 basis points. The BSA mechanism (decoupling) is applied monthly in order to mitigate the volatility of revenues and customer bills caused by abnormal weather and customer participation in energy efficiency programs.

In December 2009, Washington Gas filed for a revenue normalization adjustment (RNA) designed to decouple the company's non-gas revenue from actual volumes delivered, and to mitigate differences in revenues that occur due to: weather that varies significantly from normal; and, changes in customer usage that result from customers' energy conservation programs. On Dec. 17, 2010, the PSC issued an order rejecting the proposal.

Florida--Legislation enacted in 2008, directed the Florida PSC to analyze revenue decoupling and provide a report and recommendations to the governor and Legislature by Jan. 1, 2009. While the PSC Staff report did not contain specific recommendations regarding revenue decoupling, it did note that many of the benefits of decoupling are achieved through the PSC's authorization of various adjustment clauses that permit timely recovery of certain capital and operating expenses.

Georgia--Since 1998, Atlanta Gas Light (ATGL) has had in place a modified straight-fixed-variable rate design that enables the company to recover non-gas costs throughout the year consistent with the incurrence of these costs, thus minimizing the need for a decoupling mechanism. Initially, ATGL instituted a level monthly charge per customer for gas distribution services. The Georgia PSC subsequently replaced this level monthly charge with a sculpted rate that reduces the amount collected during summer months and increases the charge in the winter.

Hawaii--On Aug. 31, 2010, the Hawaii PUC issued an order permitting Hawaiian Electric, Hawaii Electric Light, and Maui Electric to implement a revenue decoupling mechanism coincident with the Commission's issuance of an interim or final order in the utilities' pending general rate proceedings. On Feb. 25, 2011, the PUC issued a final order in a pending rate case for Hawaiian Electric in which a full decoupling mechanism was permitted.

Idaho--In 2007, the Idaho PUC approved, on a pilot basis, Idaho Power's (IP's) request to implement a decoupling mechanism, referred to as a Fixed Cost Adjustment. The mechanism is designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy sales. Actual sales are adjusted for weather, and there is a 3% cap on annual rate increases. The pilot program is applicable to residential and small customers only. The pilot program began on Jan. 1, 2007; the first adjustment occurred on June 1, 2008, and subsequent adjustments are to occur on June 1 of each year. On April 29, 2010, the PUC denied IP's request to operate under the decoupling mechanism on a permanent basis. Instead, the Commission ordered IP to continue the program on a pilot basis through 2011.

Illinois--In the context of rate cases decided in 2008 for Integrys Energy Group subsidiaries Peoples Gas Light & Coke and North Shore Gas, the Illinois Commerce Commission (ICC) approved a four-year pilot program for a volume balancing adjustment (VBA) rider to decouple the companies’ delivery charge revenues from sales in order to eliminate the impact on margins of variations in weather, customer participation in conservation programs, and certain other factors.

In rate cases decided in 2008, Ameren Corp. subsidiary Ameren Illinois (then know as Central Illinois Light, Central Illinois Public Service, and Illinois Power) had sought ICC approval of revenue decoupling mechanisms for the company's gas operations. In lieu of approving a revenue decoupling mechanism, the ICC authorized the company to recover a greater portion of its overall revenue requirement through the fixed monthly customer charge rather than through variable charges. In 2009, the ICC approved similar rate design treatment for Nicor subsidiary Northern Illinois Gas.

Indiana--Indiana Gas (IG) and Southern Indiana Gas & Electric (SIGECO) utilize energy efficiency riders to recover the costs associated with their natural gas energy efficiency programs. The energy efficiency riders are comprised of: an Energy Efficiency Funding Component, which provides for recovery of the costs to fund these programs; and, a Sales Reconciliation Component (SRC), to provide the companies an opportunity to recoup revenues lost as a result of the conservation programs. The margin differences accumulated through the SRC are deferred without carrying charges for recovery/refund beginning April 1st of each year.

We note that in a pending proceeding (Cause No. 43959), Indiana Michigan Power proposed to recover the lost revenues attributable to the company's energy efficiency programs, as is permitted by its energy efficiency cost recovery rider. Indianapolis Power & Light utilizes an energy efficiency rider that permits the company to retain a portion of the savings associated with certain customer conservation programs.

SIGECO and IG utilize a normal temperature adjustment (NTA) mechanism to eliminate the impact of weather deviations on gas distribution revenues. The NTA mechanisms permit SIGECO and IG to normalize the recovery of margin (revenues less gas costs) from ratepayers, relative to the amount imputed in base rates.

Kansas--In January 2011, the Kansas Corporation Commission approved a request by Westar Energy/Kansas Gas & Electric to participate in the "Efficiency Kansas" energy efficiency program and to recover the related lost revenues through the company's energy efficiency cost recovery rider. Weather normalization adjustments (WNAs) are in place for Kansas Gas Service and Black Hills/Kansas Gas Utility (KGU). Under the WNA, rate adjustments are implemented at the end of the heating season based on the difference between actual and normal weather as measured by degree days. The companies accumulate differences in a deferred account and either implements a surcharge or credit on customer bills for the 12-month period beginning each April 1.

Kentucky--A weather normalization adjustment (WNA) mechanism is in place for Atmos Energy; this mechanism is to remain in place through Oct. 31, 2011. A WNA is also in place for Columbia Gas of Kentucky (CGK), Delta Natural Gas, and Louisiana Gas & Electric's gas operations. Since 2008, Delta has utilized a customer conservation efficiency program (CEP) cost recovery mechanism (essentially a decoupling mechanism) that reflects CEP cost recovery, a revenue adjustment to account for lost sales, and incentive mechanisms. Duke Energy Kentucky (DEK), CGK, LG&E, and Delta also utilize riders to recover lost revenue associated with gas conservation programs and these mechanisms include certain incentive provisions. LG&E, DEK, Kentucky Utilities, and Kentucky Power also utilize a similar CEP mechanism for their electric businesses.

In the context of a rate proceeding decided in 2009, CGK had proposed to phase in, over a two-year period, an SFV rate design. However, in a settlement that was adopted in the case, CGK was permitted to implement the entire rate increase through an increase in the company's fixed monthly customer charge.

Louisiana--Atmos Energy and CenterPoint Energy Resources utilize weather normalization adjustment mechanisms that are to remain in place until terminated by the Louisiana PSC.

Maine--While there are no current decoupling plans in place, Maine was one of the first states to experiment with such mechanisms in the early 1990's.

Maryland--In 2007, the Maryland PSC approved monthly bill stabilization adjustment (BSA) mechanisms for Potomac Electric Power and Delmarva Power & Light that are designed to mitigate the volatility of customer bills during colder- and-warmer-than-normal weather conditions, and the impact of customer participation in energy efficiency programs. A BSA mechanism was implemented for Baltimore Gas & Electric in 2008. A weather normalization clause is in place for Columbia Gas of Maryland, and Washington Gas has a revenue normalization mechanism in place.

Massachusetts--In 2008, the DPU ordered all electric and gas utilities to implement full revenue decoupling mechanisms as part of each company's next base rate proceeding. The DPU expects all companies to have operational decoupling plans in place by year-end 2012. Decoupling reconciliation filings are to be made on an annual basis, with additional filings to be required if the company exceeds a threshold of 10% above or below target revenues. During the transition (2009 through 2012) to the implementation of fully decoupled rates, electric distribution utilities are to be permitted to recover lost base revenues (LBR) resulting from the implementation of their three-year energy efficiency plans. Gas distribution companies are currently allowed recovery of energy-efficiency-related LBR through their local distribution adjustment mechanisms.

Since the July 2008 DPU directive, full revenue-per-customer decoupling mechanisms were adopted for Columbia Gas of Massachusetts (formerly Bay State Gas) on Oct. 30, 2009, for Massachusetts Electric and NE on Nov. 30, 2009, and Boston Gas/Essex Gas/Colonial Gas on Nov. 2, 2010, for Western Massachusetts Electric on Jan. 31, 2011, and New England Gas on March 31, 2011. The decoupling mechanisms adopted include a cap on decoupling adjustments, with any amounts above the cap to be deferred for future recovery, with carrying charges.

Michigan--In 2009, the PSC adopted full revenue decoupling mechanism for Consumers Energy's (CE's) electric operations and for Upper Peninsula Power. The Commission authorized Detroit Edison a full pilot revenue decoupling mechanism in January 2010. Senate Bill 213, enacted in October 2008, permits a gas utility that spends at least 0.5% of its revenue on energy efficiency programs to institute a revenue decoupling mechanism. In 2010, the PSC adopted energy efficiency related pilot revenue decoupling mechanisms for the gas operations of CE, Michigan Consolidated Gas, and Michigan Gas Utilities.

Minnesota--In a Jan. 11, 2010 rate case decision for CenterPoint Energy Resources, the PUC adopted a pilot revenue decoupling mechanism to make the company whole for revenue fluctuations due to energy conservation initiatives; the mechanism does not adjust for revenue variances caused by abnormal weather.

Missouri--In 2007, the Missouri PSC adopted Missouri Gas Energy's (MGE's) proposed SFV rate design for residential customers, whereby all of the company's fixed costs allocable to that customer class are to be recovered through a fixed, monthly customer charge. MGE is a subsidiary of Southern Union. In August 2010, the PSC adopted a settlement that requires Atmos Energy to terminate its SFV rate design and utilize a traditional rate design under which a portion of fixed costs are recovered through volumetric rates.

Montana--In December 2010, NorthWestern Energy was authorized to implement a four-year energy-efficiency-related pilot revenue decoupling mechanism for its residential and small-general-service electric customers only. The PSC did not elaborate on why it rejected the decoupling proposal for gas customers. In its decision, the Commission opined that the decoupling mechanism "will more completely eliminate any incentive for [NorthWestern] to promote sales, and better remove financial disincentives to certain conservation and energy efficiency activities."

MDU Resources' utilizes a tracking mechanism to recover the costs associated with gas-related conservation programs, as well as to recoup revenues lost as a result of the programs.

Nebraska--In 2009, in the context of a generic docket, the Nebraska PSC concluded that it has the authority to consider utilities' requests to implement revenue decoupling mechanisms under the condition that the mechanisms would not bring about changes to the utilities' overall revenue requirements. Such mechanisms have yet to be proposed. We note that in the PSC recently rejected a SourceGas Distribution request to implement revenue decoupling. However, the Commission authorized the company to increase its monthly customer charges by 10% (residential), 8% (small commercial), and 82% (large commercial).

Nevada--In 2009, Senate Bill (S.B.) 358 was enacted, requiring the Nevada PUC to adopt regulations for electric utilities that address the recovery of costs associated with energy efficiency and conservation programs. The PUC adopted regulations designed to allow electric utilities to recover lost revenue due to energy efficiency and conservation programs. The regulations state that the electric utilities may recover an amount based on the effects of energy efficiency and conservation programs included in the company's Commission-approved demand-side management plan. The amount recovered is to include the costs incurred and the associated lost revenue. The PUC may permit an electric utility to recover any financial incentives offered to support customer participation in the conservation programs. The lost revenues for Sierra Pacific Power and Nevada Power are to be recovered using a balancing account.

In 2007, S.B. 437 was enacted, requiring the PUC to adopt rules to establish regulations designed to remove the financial disincentives for natural gas utilities to support energy conservation efforts. The PUC-established rules, which were ratified by the Legislature in 2009, require a gas utility seeking decoupling to include, as part of its application, "a discussion identifying any change in risk for the gas utility and a calculation to adjust for the change in risk and demonstrate the impact of the current and requested rate design for the gas utility." On Oct. 28, 2009, the PUC adopted revenue decoupling mechanism for Southwest Gas. This mechanism is a full decoupling plan, thus eliminating the company's risk associated with weather variations.

New Hampshire--In 2007, the New Hampshire PUC opened a proceeding (Docket No. DE 07-064) to investigate rate mechanisms, such as revenue decoupling, that could be instituted to remove obstacles for encouraging investments in electric and gas energy efficiency. The PUC ultimately concluded that such mechanisms should only be implemented on a company-by-company basis in the context of a rate case that would examine company-specific revenues, costs, service territory, customer mix, and rate base investment. As part of a rate case decided in March 2011, EnergyNorth Natural Gas had requested a revenue decoupling mechanism; however, the PUC adopted a settlement in the proceeding that did not include such a mechanism.

New Jersey--In 2006, the New Jersey Board of Public Utilities (BPU) approved pilot energy conservation programs and revenue decoupling mechanisms that had been proposed by New Jersey Natural Gas and South Jersey Gas. These "conservation incentive programs" (CIPs) are designed to remove the impact on earnings and revenue of sales fluctuations due to weather variations and customer participation in the conservation programs that are part of the CIPs. Operation of the mechanisms is contingent on the companies' achieving certain demand-reduction targets. On Jan. 20, 2010, the BPU approved the extension of the CIPs through 2013.

A weather normalization clause (WNC) is in place for Pivotal Utility Holdings (PUH), under which rate adjustments are made after the end of the heating season based on the difference between actual and normal weather, as measured by degree days. No adjustment is made if actual weather is within plus or minus 0.5% of the sum of the cumulative normal calendar month degree days for the heating season. PUH may not implement an increase in the WNC if the increase will result in the company earning a return in excess of that last authorized. Public Service Electric & Gas has a WNC in place that was approved as part of a 2010 rate case decision.

New Mexico--In a 2007 gas rate decision for Public Service Company of New Mexico (PSNM), the New Mexico Public Regulation Commission (PRC) rejected PSNM's proposed decoupling mechanism, stating that the decoupling proposal was too broad. The PRC concluded that the mechanism would make PSNM whole for past conservation efforts of consumers and was therefore fatally flawed. The PRC stated that it would not consider a decoupling mechanism of this type in any case. The company has since sold its gas business. In a pending PSNM electric rate case in which the company had requested implementation of a decoupling mechanism, a settlement was filed on Feb. 3, 2011, that does not include decoupling.

North Carolina--Since 2005 Piedmont Natural Gas has utilized a Margin Decoupling Mechanism/Tracker (MDT), formerly known as the Customer Utilization Tracker (CUT), that decouples the recovery of authorized margins from sales levels, thus mitigating the impact of weather and energy conservation programs. Public Service Co. of North Carolina was authorized to implement a CUT in 2008.

North Dakota--Northern States Power's residential gas rates have been fully decoupled through the adoption of an SFV rate design. In a 2005 rate case decision, the North Dakota PSC approved a flat monthly delivery service charge, replacing the fixed basic service charge and a per therm volumetric distribution charge. Northern States Power is a subsidiary of Xcel Energy.

Ohio--In a 2008 gas rate decision for Duke Energy Ohio, the Ohio PUC adopted a straight fixed variable rate design that increased residential customers' fixed charge to $20 from $6, and reduced the negative effect on company revenues caused by customer conservation efforts. The PUC noted that this change largely accomplishes the goals of decoupling without the need for an annual audit of the mechanism and subsequent true-ups. Similar rate designs were later adopted for East Ohio Gas, Columbia Gas, and Vectren Gas Delivery of Ohio. The electric security plans for each of the Ohio electric utilities includes a rider that allows for recovery of energy efficiency program costs and lost distribution margin associated with these programs.

Oklahoma--Oklahoma Gas & Electric utilizes a demand program rider to recover the costs associated with certain energy efficiency programs and the related lost net revenues.

Oregon--In January 2009, the Oregon PUC adopted an electric revenue decoupling mechanism for Portland General Electric (PGE) to be initially effective Feb. 1, 2009, for a two-year trial period. On Dec. 17, 2010, the PUC extended the mechanism to year-end 2013. The mechanism is designed to provide for the recovery of reduced revenues resulting from reduced consumption patterns of residential and certain commercial customers' conservation efforts.

Northwest Natural Gas uses a decoupling mechanism designed to counteract the impact on revenues of changes in average consumption patterns due to residential and commercial customers' conservation efforts. The company has a separate weather-adjusted rate mechanism (WARM) in place for residential and commercial customers. Customers are permitted to opt out of WARM (about 10% do not participate), and the program is to be in place through Oct. 31, 2012.

Pennsylvania--While there have been no decoupling mechanisms or weather normalization clauses approved for either electric or gas utilities in the state, in certain recent rate cases the Pennsylvania Public Utility Commission (PUC) has authorized the companies to increase monthly fixed customer charges so that a greater portion of fixed costs are recovered through the fixed-charge component of customer bills. The PUC approved this type of treatment as part of a rate case settlement for: Columbia Gas of Pennsylvania in 2010; PECO Energy (electric and gas) in 2010; UGI Central Penn Gas in 2009; and, UGI Penn Central in 2009.

Rhode Island--In a gas rate case for Narragansett Electric in which an order was issued in January 2009, the Rhode Island PUC declined to adopt the company's proposed decoupling mechanism, concluding that there was not much evidence of its impact on ratepayers. In a February 2010 electric rate decision, the PUC declined to adopt a revenue decoupling mechanism for NE's electric operations. We note, however, that since the issuance of those decisions, legislation was enacted (in May 2010) that directs the PUC to utilize revenue decoupling mechanisms for electric and certain gas utilities in the state. On Oct. 18, 2010, NE filed a request with the PUC to implement revenue decoupling mechanisms for its electric and gas operations.

NE has a weather normalization clause under which the company is required to return to gas customers the margin impact of weather that is at least 2% colder than normal, and may recover the margin impact of weather that is greater than 2% warmer than normal.

South Carolina--On July 15, 2010, the Commission authorized South Carolina Electric & Gas (SCE&G) a 12-month pilot electric weather normalization mechanism for residential and small general service commercial customers. Gas weather normalization adjustments have been in place for several years for SCE&G and Piedmont Natural Gas that apply to residential and small commercial customers during winter months.

Tennessee--In May 2010, the Tennessee Regulatory Authority authorized Chattanooga Gas to implement a full revenue decoupling mechanism on a pilot basis for a three-year period.

Texas RRC--As part of 2006 rate case filing, Atmos Energy sought a "revenue stabilization" (decoupling) mechanism and a weather normalization adjustment (WNA) that would be based on 10 year average data. The parties subsequently reached an agreement, whereby Atmos was permitted to implement an interim WNA, effective Oct. 1, 2006, that was based on 30-year average data. In 2007, the RRC approved a settlement providing for Atmos to implement a WNA based on 10 years of historical data (versus the 30-year data included in the settlement). The revenue stabilization adjustment was not approved. A WNA mechanism is also in place for a portion of Texas Gas Service's operations. In addition, in recent rate cases for Atmos Energy (2010) and CenterPoint Energy Resources (2010), the RRC approved increases in fixed monthly customer charges in order to allow the companies to collect a greater portion of their fixed costs through these charges.

Utah--A weather normalization adjustment (WNA) is in place for Questar Gas. However, customers may elect not to participate in the WNA. Additionally, since 2006, Questar Gas has operated under a conservation-enabling tariff (CET), which decouples non-gas revenues from the volume of gas used by customers. Under the CET, a margin-per-customer target is specified for each month, with differences to be accrued in a balancing account that is capped at 5% of distribution non-gas (DNG) revenues. The accrued balance is subsequently flowed through to ratepayers; annual amortization of accrued balances is capped at 2.5% of DNG revenues, with any balance exceeding the amortization cap to be carried forward for future amortization. A 2010 rate decision that followed a settlement, provided for the CET to continue beyond its year-end 2010 expiration date and to no longer be considered a pilot program. In 2009, Senate Bill (S.B.) 75 was enacted, codifying the Utah PSC's policy of permitting the use of revenue decoupling mechanisms.

Vermont-- We note that the alternative rate plans adopted by the Vermont Public Service Board for Green Mountain Power, Central Vermont Public Service, and Vermont Gas Systems somewhat obviate the need for revenue decoupling mechanisms, as the plans allow for annual rate adjustments based on the company's forecast of sales and costs.

Virginia--A Weather Normalization Adjustment (WNA) Rider is in place for Virginia Natural Gas (VNG). Separate WNA factors are calculated for each customer class, such that when applied to the billed volumes for each rate class as a surcharge or credit, the WNA factors produce a bill that recovers VNG's cost of service as approved by the SCC under normal weather conditions. In 2007, the SCC adopted a settlement allowing Washington Gas (WG) to implement a similar WNA, and in a settlement adopted by the SCC in December 2010, Columbia Gas of Virginia (CGV) was authorized to implement a weather normalization clause and to increase its monthly fixed charges.

In 2008, the SCC approved a revenue normalization adjustment (decoupling) mechanism designed to mitigate the impact on VNG's revenues of residential customer participation in energy conservation programs. Similar mechanisms were subsequently approved for both WG and CGV.

Washington--On Nov. 4, 2010, the WUTC issued a policy statement regarding regulatory mechanisms, including decoupling. However, we note that limited decoupling plans have previously been approved for certain utilities' gas operations. The WUTC indicated that adoption of decoupling mechanisms for electric and gas utilities would be considered in the context of a rate case, with revenue recovery conditioned upon a utility's level of achievement with respect to its conservation targets. The WUTC indicated that it would consider adoption of a full decoupling mechanism ("designed to minimize the risk to both the utilities and to ratepayers of volatility in average use per customer by class regardless of cause, including the effects of weather"), for electric and gas utilities. The WUTC indicated that it would only consider limited decoupling mechanisms (described as a lost margin recovery mechanism that would allow the utility to recovery lost margin due only to the utility's conservation efforts including educational and informational) for gas utilities.

We note that such limited decoupling plans for gas utilities have been adopted in the past (see below). The Commission indicated that a proposal to implement such mechanisms is to contain several elements including: (1) a true-up mechanism, (2) impact on rate of return, and, (3) an earnings test.

We note that as part of a settlement reached in connection with the acquisition of PSE parent Puget Energy Inc. by Puget Holdings LLC, PSE agreed to refrain from proposing a decoupling mechanism for its electric and gas operations until at least early-2011.

In 2007, the WUTC approved a partial decoupling mechanism for Cascade Natural Gas (CNG) to be in effect on a three-year pilot basis effective Oct. 1, 2007, the terms of which were agreed to in a settlement. Approval of the decoupling mechanism was subject to WUTC approval of a conservation plan, which was subsequently approved by the Commission. Earnings were to be capped at the company's overall rate of return. Penalties were to be levied if CNG failed to meet established conservation benchmarks and targets. The pilot, which ended on Sept. 30, 2010, was only to be extended if part of a general rate case. While CNG has not filed a rate case, the company filed a request on Oct. 1, 2010, seeking to extend the mechanism. The request was ultimately withdrawn after the WUTC issued its Nov. 4 policy statement.

Avista has operated under a decoupling mechanism that applies only to residential and small commercial gas customers. The plan was initially adopted in February 2007, and was to be in place on a 2.5-year pilot basis, beginning in Jan. 1, 2007. Avista deferred 90% of the margin difference (i.e., fixed costs), which was to be recovered from or returned to customers. The recovery of any deferred costs was subject to both an earnings test that would prohibit collection if Avista is earning above its authorized rate of return, and a demand-side management (DSM) test that would prohibit collection if specific conservation targets were not achieved. Rate adjustments associated with the mechanism in any one year were limited to no more than 2%. The plan was extended beyond the end of the pilot period (June 30, 2009) on a permanent basis, with modifications. Specifically, Avista is to defer 45% of the margin difference, with the recovery of any deferred costs to continue to be subject to an earnings test and a DSM test. Rate adjustments associated with the mechanism are to continue to be limited to no more than 2%.

West Virginia--While there have been no decoupling mechanisms or weather normalization adjustment mechanisms (WNAs) approved for the major electric or gas utilities in the state, the West Virginia Public Service Commission (PSC) has approved WNAs for certain smaller local gas distribution companies on a pilot basis (the program extends through 2014). In the context of a rate case decided in December 2009, the PSC rejected Dominion Resources subsidiary Hope Gas' request for approval of a WNC, finding that the operational characteristics of Hope (versus the eight smaller companies that are part of the pilot) render a WNA unnecessary for Hope and stated that it "does not believe that Hope must necessarily await the outcome of the pilot program, but a larger gas utility such as Hope is fully capable of absorbing downward swings in revenue in warmer than normal winters. This revenue shortfall is not a permanent revenue shortfall because Hope is allowed to keep the increased revenue generated in colder than normal winters."

In addition, as part of a 2009 joint rate case settlement for Monongahela Power/Potomac Edison, the PSC approved an increase in the monthly customer charge for residential customers so that a greater portion of fixed costs are recovered through these charges. As part of a 2010 rate case settlement for Mountaineer Gas, the PSC approved increases in fixed monthly customer charges for all customer classes.

Wisconsin--In December 2008, the Wisconsin PSC authorized Wisconsin Public Service to implement four-year, full pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers. The mechanisms limit rate changes to plus or minus $14 million for electric and plus or minus $8 million for gas operations.

Wyoming--In December 2010, the Wyoming PSC rejected SourceGas Distribution's (SG's) proposal to implement decoupling for certain transmission/storage service customers in the Casper service area; however, the Commission approved the company's request to implement decoupling for small and medium general service class distribution customers in all three of SG's service areas, stating its intention to "move in the direction of making the Company indifferent to the effects of reduced use, and toward fairly and directly compensating the Company for the use of its distribution facilities, rather than being dependent on the overall amount of gas it can persuade its customers to buy to recoup those distribution costs through sales volumes." The adopted decoupling mechanism does not take effect until January 2012. Weather normalization is not part of this decoupling mechanism.

In rejecting decoupling for small and medium general service class transmission/storage service customers, the PSC opined that the company did not present sufficient evidence in the proceeding to warrant the implementation of such a mechanism for those customers.