BEFORE THE

STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

	)	
IN RE: INVESTIGATION AS TO	**)**	
THE PROPRIETY OF THE	**)**	
NARAGANSETT ELECTRIC	**)**	**Docket No. 4065**
COMPANY'S (d/b/a NATIONAL	**)**	
GRID) PROPOSED TARIFF	**)**	
CHANGES	**)**	
	)	

DIRECT TESTIMONY

OF

MARK NEWTON LOWRY, PhD

Submitted on Behalf of the Energy Efficiency and Resource Management Council

September 15, 2009

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please State Your Name And Business Address.

My name is Mark Newton Lowry. My business address is 22 East Mifflin St. Suite 302, Madison, Wisconsin 53703.

Q. By whom and in what capacity are you employed?

I am the President of PEG Research LLC, a company in the Pacific Economics Group consortium which is active in the fields of alternative regulation ("Altreg") and statistical research on utility performance. My duties in that capacity include the management of the company, the design of Altreg plans, supervision of statistical research, and expert witness testimony. I have testified numerous times on Altreg and utility performance issues. Venues for my testimony have included California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Vermont, Alberta, British Columbia, Ontario, and Quebec. Our practice is international in scope and has to date included projects in eleven countries. We work for a mix of utilities, regulators, and public agencies has given us a reputation for objectivity and dedication to economic science.

Revenue decoupling is a form of Altreg and is one of my specialties. I have provided relevant testimony in proceedings leading to the approval of ten decoupling plans, including plans for BC Gas (d/b/a Terasen Gas), Central Vermont Public Service, Enbridge Gas Distribution, San Diego Gas and Electric, and Southern California Gas. I am currently testifying on decoupling plans for three electric utilities and have published four articles that address decoupling issues.

Before joining PEG I worked for eight years at Christensen Associates, first as a senior economist and later as a Vice President and director of that company's Regulatory Strategy practice. My career has also included work as an academic economist. I was an Assistant Professor of Mineral Economics at the Pennsylvania State University and a visiting professor at l'Ecole des Hautes Etudes Commerciales in Montreal.

In total, I have twenty five years of experience as a practicing economist, spending the last twenty years addressing utility issues. I hold a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin. I have served as a referee for several scholarly journals and have an extensive record of professional publications and public appearances. My resume is attached as Schedule EERMC-MNL-1.

Q. On whose behalf are you appearing in this proceeding?

I am testifying on behalf of the Energy Efficiency and Resource Management Council (the "Council" or "EERMC"). The Council, which represents diverse stakeholders in Rhode Island regulation, advises the state regulatory community on energy efficiency ("EE"), distributed generation ("DG"), and renewable resource issues.

Q. What is the purpose of your testimony?

The goal of my testimony is to provide the Commission with additional information on revenue decoupling that may prove useful in appraising National Grid's decoupling proposal in this proceeding. The plan for my testimony is as follows. I first discuss the nature of revenue decoupling, the rationale for decoupling, and key precedents. I then develop criteria for comparing alternative approaches to decoupling and use these criteria in evaluate the established decoupling approaches. In the final section of my testimony I use this analysis to consider whether National Grid's decoupling proposal makes sense for Rhode Island.

Q. Please present your main conclusions.

I find that revenue decoupling is a desirable component of the regulatory system for National Grid in Rhode Island. Implementation of all efficient EE and DG is a goal of state policymakers. Decoupling is a key to the realization of this goal. The trueup approach to decoupling that the Company proposes is the best practice approach because it encourages, at a reasonable administrative cost, the full range of measures that can promote clean energy. These advantages help to explain why decoupling trueup plans are spreading rapidly in the gas and electric power industry and are used or scheduled for use in most states that have a strong commitment to clean energy. I encourage the Commission to approve a decoupling trueup plan for National Grid.

II. REVENUE DECOUPLING

Q. Please explain the concept of revenue decoupling.

Revenue decoupling is a form of regulation in which the special link that has traditionally existed between a utility's earnings and the usage of its system is broken. Two approaches have been established that, with differing degrees of success, sever this linkage: decoupling true-up plans and straight fixed variable ("SFV") pricing.

Q. What are decoupling true up plans?

A decoupling trueup plan commonly has two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM makes a regularly scheduled sequence of rate adjustments that cause a company's actual revenues to track its approved revenue requirement more closely. True-up mechanisms usually involve a balancing account in which past differences between revenue and the revenue requirement are entered. The accumulated net balance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. Trueups may be made monthly, quarterly, or annually. The rate adjustments to clear the balancing account are likely to take the form of surcharges in some years and credits in others.

Q. What is a revenue adjustment mechanism?

The RAM component of a decoupling plan adjusts the revenue requirement between rate cases, generally on an annual basis. To understand the need for a RAM, note first that the cost of service normally rises between rate cases due to some combination of input price inflation, plant additions, and output growth. Since decoupling eliminates the opportunity for a utility to gain increased revenues through sales growth, an adjustment mechanism is appropriate to enable the utility recover its cost of service. In the few decoupling trueup plans that have no RAM, utilities therefore typically file annual rate cases[1]. When RAMs provide escalation for changes in a wide range of the business conditions that drive cost they provide the basis for multiyear rate plans that can extend the period between rate cases.

Q. What is SFV Pricing?

In principle, SFV pricing means an approach to rate design that recovers in usage (*e.g.* demand and volumetric) charges only those costs that vary, in the short run, with usage. In practice, it has been an approach to rate design that eliminates volumetric charges for base rate inputs. The lost revenue is recovered by raising other rate elements. For commercial and industrial customers ("C&I"), this commonly involves higher customer and demand charges, notwithstanding the fact that cost is for the most part mixed in the short run with respect to maximum demand. For residential customers, who typically do not have interval meters or other advanced metering infrastructure ("AMI"), SFV pricing involves only higher customer charges.

Q. What is the rationale for revenue decoupling?

The most widely advanced rationale for revenue decoupling for electric utilities is its ability to facilitate greater efficiency in the use of the central generation, transmission, and distribution system (hereafter, the "electric system"). The earnings of energy utilities

[1] *See*, for example, the recent decoupling experience of Central Hudson Electric & Gas and Consolidated Edison of New York.

depend primarily on the difference between the costs of capital and other non-energy inputs that they use and the revenues generated from the "base" rates that are designed to recover these costs. While the cost of base rate inputs is substantially fixed in the short run with respect to system use, a large share of this cost is nonetheless typically recovered through usage charges. Reductions in system use therefore reduce utility earnings between rate cases.

These realities can disincent utilities from encouraging greater efficiency in the use of the electric system. Decoupling can remove this disincentive. To the extent that efficient EE, peak system use, and customer-sited DG are thereby promoted, substantial benefits ensue. Customer bills will be lower. The reduction will be greatest in customer outlays for central generating services, whose cost is tied more closely to the amount of power purchased, but outlays for distribution and transmission services may also be lowered, especially in the longer run. The U.S. electric system is one of the largest sources of greenhouse gases and other airborne pollutants in the world. EE and investments in customer-sited renewables and combined heat and power ("CHP") facilities can help to contain the environmental damage. EE and customer sited renewables also reduce reliance on price volatile power and fossil fuels. To the extent that central generating stations use petroleum fuels, EE and DG also reduce our nation's dependency on oil imports.

Q. Does decoupling provide utilities with a sufficient incentive to promote clean energy aggressively?

No. Decoupling cannot by itself induce utilities to be aggressive proponents of DSM and DG. Most notably, utilities also need compensation for the cost of administering their DSM and DG initiatives. Incentives to encourage efficient programs are also desirable.

Q. What if the utility doesn't administer the EE program?

The incentive benefits of decoupling are reduced somewhat if programs to promote EE are undertaken by independent agencies rather than utilities[2]. However, utilities often can influence the *budgets and programs* for these agencies.

Q. Are there other ways in which a utility can promote efficient system use?

Yes. In all states, the utilities can promote efficient system use in various ways which go beyond the EE programs. The alternative avenues for promoting more efficient use include

- Rate design;
- Utility policies, other than rate design, that affect DG (*e.g.* net metering, feed in tariffs, & connections);
- Support for government policies outside the regulatory arena that promote EE and/or customer-sited DG (*e.g.* appliance efficiency standards, building codes, tax credits, and public funding of research and development); and
- Other promotional measures (*e.g.* advertising and other informational activities that promote EE and customer-sited DG, facilitation of customer

[2] Such agencies have been established in Hawaii, Maine, New Jersey, New York, Oregon, Vermont and Wisconsin.

contact with independent EE and DG service providers, and the sharing of information with these providers) which take advantage of a utility's reputation and its regular contact with customers.

A company can try hard with respect to one approach but undermine its effect on system use efficiency by not trying hard with respect to other approaches. As one example, the effect of a large appliance rebate program can be undermined by opposition to more stringent appliance efficiency standards. As another, the effect on customer-sited photovoltaic generation of a generous net metering policy can be mitigated by slow progress in installing AMI that makes possible time of use ("TOU") and other kinds of peak load pricing. A decoupling method is more effective to the extent that it separates earnings from all means of promoting sales. A decoupling method may be said to be "broad based" to the extent that it encourages all means of promoting efficient system use.

Q. How important are these supplemental avenues for the promotion of efficient system use?

One gauge of their importance is that decoupling true up plans of some form are operational in five states (New York, New Jersey, Oregon, Wisconsin, and Vermont) in which most EE programs are independently administered.

The Oregon PUC stated, in its order approving a second decoupling plan for Portland General Electric ("PGE") this year, that

> While the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the [Energy Trust of Oregon ("ETO")] running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether its supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE[3].

The Connecticut Department of Public Utility Control stated, relatedly, in its recent order approving a decoupling plan for United Illuminating that it was approving the plan not because of its effect on the company's EE program but for its effect on "areas where UI does not already receive incentives"[4]. The Department goes on to explain that

> UI is still viewed as *the* energy provider by the general body of ratepayers. The Department believes that this will not change…Success in achieving Connecticut's energy policy goals requires that the Department take advantage of this relationship to promote the energy-related programs and policies that have been recently set in place.[5]

Q. Please discuss any additional benefits of decoupling.

Some benefits stem from its general ability to afford utilities relief from the financial impact of declines in sales per customer. Secular declines in sales per customer can result from various circumstances that include aggressive conservation programs, high power prices, more stringent appliance efficiency standards and building codes, and an expansion of DG. Irrespective of whether declines are due to the utility's actions, they

[3] UE 197, January 2009, p. 27
[4] Connecticut DPUC, Decision, Docket 08-07-04, February 2009, p. 121.
[5] *Ibid*, pp. 121-122.

increase financial attrition between rate cases. Decoupling can make utilities whole for declines from all these sources without enabling them to receive revenues which exceed their requirements. In so doing, it promotes just and reasonable compensation for a legitimate financial challenge and reduces the risk of under-compensation that might otherwise result. Decoupling can also stabilize revenue in the face of volume fluctuations that result, in the short run, from changes in weather and local economic activity. "Full" decoupling occurs when revenue tracks the revenue requirement closely and is not permitted to deviate due to volume fluctuations due to weather or other specific sources.

The reduced risk of sales fluctuations and a more secular decline in average sales can lower the cost of obtaining funds in capital markets and this benefit can be shared with customers. However, the implementation of decoupling will not necessarily coincide with a lower allowed rate of return. The existing rate of return target may not reflect emerging risks. To the extent that declining average sales is an emerging problem, for instance, the existing rate of return may not reflect this risk. Operation under a RAM for several years without rate cases involves cost recovery risk, as just noted.

Q. Does decoupling then guarantee that a utility earns its allowed rate of return?

No. The utility must still manage its cost to ensure that it is less than or equal to the revenue requirement. This can be challenging, especially when the firm commits to a multi-year rate case moratorium.

Q. Are there other benefits to decoupling?

Yes. Automatic compensation for fluctuations and secular declines in system use can also increase the efficiency of regulation. For example, decoupling can reduce the importance of load forecasts in rate cases. These are often a subject of considerable controversy. Calculations of the margins lost due to EE programs can be eliminated except where needed to provide the basis for supplemental EE awards and penalties. The frequency of rate cases can be reduced since an important source of financial attrition is being addressed by other means.

Q. Do companies with declining sales per customer *always* file frequent rate cases?

No. The frequency of rate cases also depends on the cost pressures that a company faces in addition to volume growth. In a period of unusually slow input price inflation, rapid productivity growth, and low investment requirements, for instance, a company might be able to absorb the impact of slow volume growth without a rate case. A coincidence of such favorable conditions is rare, however, and rate cases do tend to be less frequent under decoupling on average over time. The improvement in the efficiency of regulation can be furthered to the extent that RAMs provide the basis for multi-year rate plans.

Q. What are the concrete benefits of increased regulatory efficiency?

The benefits of regulatory efficiency can be manifested in several ways. Regulatory cost may be reduced. A single rate case can result in thousands of pages of testimony and discovery documents. Alternatively, cost savings may permit a redirection of regulatory resources to improve regulation in other areas. Such economies are especially useful in a period of rapid change, when a host of new regulatory issues may arise. Reducing the frequency of rate cases also strengthens a utility's incentives to contain cost, and senior managers can devote more time to the basic business of providing quality service at a reasonable cost. Cost performance should improve leading, in the long run, to lower rates for customers. While the Commission and stakeholders have an understandable interest in holding rate cases periodically, annual or biennial rate cases are generally excessive. A desire to reduce the frequency of rate cases is an important motivation for many trackers in utility ratemaking, including those for pension expenses and plant additions.

Q. Please discuss the precedents for decoupling.

The bulk of North American experience with the true up approach to decoupling has occurred in California. Decoupling began there in the late 1970s in the natural gas industry to encourage conservation and protect companies from the financial consequences of slow volume growth and revenue volatility that were caused by supply curtailments and the commitment of California's Public Utilities Commission's ("PUC") to rate designs with high volumetric charges. California gas services have been subject to decoupling in most years since its inception and all of the major companies are subject to decoupling at present.

Decoupling began in California's electric power industry in the early 1980s with generally positive results. Nevertheless, when the industry was restructured in the mid 1990s to promote power market competition, the CPUC suspended decoupling for most utilities. A resumption of decoupling was required by a 2001 statute. Support for decoupling has been widespread in the regulatory community over the decades.

Q. Please discuss decoupling experience in other jurisdictions.

Decoupling was adopted to regulate electric utilities in Maine, New York, and Washington state in the early 1990s[6]. Kushler, York, and Witte discuss the impact of the decoupling mechanism in Washington[7]. They state that "Implementation of this decoupling mechanism played a critical part in changing the role of energy efficiency and conservation programs within Puget Sound Energy. In the first two years there were dramatic improvements in energy efficiency program performance." In extending the program for another three years in 1993, the WUTC observed that the decoupling mechanism "has achieved its primary goal – the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now a national leader in this area."[8]

Decoupling was suspended after a few years in all of these states. In New York, this was due primarily to the move towards power industry restructuring to promote retail

[6] The early innovators included Orange & Rockland Utilities, Niagara Mohawk Power, Consolidated Edison, Puget Sound Power & Light, & Central Maine Power.
[7] Martin Kushler, Dan York, and Patti Witte, *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives"*, Report Number U061, American Council for an Energy-Efficient Economy, Washington DC, 2006. p. 40.
[8] WUTC, 11th Supplemental Order, Sept. 21 1993.

competition. In Maine and Washington, suspension was due, in whole or in part, to higher rates but the rate hikes were in each case attributable to multiple causes. For example, in Washington the decoupling mechanism was combined with a power cost adjustment mechanism. The suspension in Washington was also due to expected industry restructuring.

Decoupling was first instituted in Oregon's electric power industry in 1995 and has been used intermittently in that state in subsequent years. One electric utility and two gas utilities currently operate under decoupling plans.

A resurgence of interest in decoupling for electric utilities outside California began in 2007. There are currently sixteen plans operative involving utilities in California, Connecticut, Idaho, Maryland, Oregon, New York, and Wisconsin. Implementation of decoupling for all utilities is now required by law or Commission mandate in four states: California, Connecticut, Massachusetts, and New York. Decoupling proposals are currently under review for electric utilities in Hawaii, Massachusetts, New Jersey, and Michigan in addition to Rhode Island. In large part, these initiatives reflect renewed state and national emphasis on reducing fossil fuel consumption to meet cost-saving, energy independence, and environmental goals.

Q. Please discuss decoupling experience in the gas industry.

Decoupling today is even more widespread in the regulation of local gas distribution companies (LDCs). Many LDCs have been experiencing declines in the average use of gas by residential and commercial customers. These declines reflect external market developments, such as high gas prices, appliance efficiency gains, and better home construction, as well as EE programs. Given typical rate designs, which feature volumetric charges well above short run marginal cost, LDCs faced with this problem will, absent decoupling, press for higher fixed charges or come in for rate cases frequently over a recurrent set of issues.

In totality, the following nineteen states and two Canadian provinces have implemented decoupling true up plans for one or more gas or electric utilities.

US: CA, CO, ID, IL, IN, FL, MD, ME, MT, NC, NJ, NY, OH, OR, UT, VT, WA, WI, WY

Canada: ONT, BC

These states are detailed on the map in Figure 1. Six states (California, Maryland, North Carolina, New York, Oregon, and Washington) that have implemented decoupling true up plans have gone on to approve other such plans.

Q. Please discuss the precedents for SFV pricing

SFV pricing has been used by the Federal Energy Regulatory Commission ("FERC") since the early 1990s to regulate natural gas pipelines. Precedents for the use of SFV in retail ratemaking have to date been confined to the gas distribution industry. The states that have adopted SFV pricing (Georgia, Missouri, North Dakota, and Ohio) are detailed in Figure 2. SFV is often rejected by states considering decoupling because it erodes customer conservation incentives and raises significant concerns about rate continuity and equity.[9]

Q. What conclusions can be drawn from this summary of precedents?

I conclude that the use of revenue decoupling in North American regulation of energy utilities is widespread and growing. Decoupling in some form is now used in almost half of all U.S. regulatory jurisdictions. Given its popularity in the gas industry, I expect that decoupling will be an increasingly common response to material declines in the volume per customer of *electric* utilities such as may result in the future from slower economic growth and increased EE and DG efforts by utilities and government agencies.

[9] *See, e.g.*, Massachusetts Department of Public Utilities, Order 07-50-A, July 16, 2008, at 27-28.

Figure 1: U.S. Decoupling Precedents by State:
True up Plans

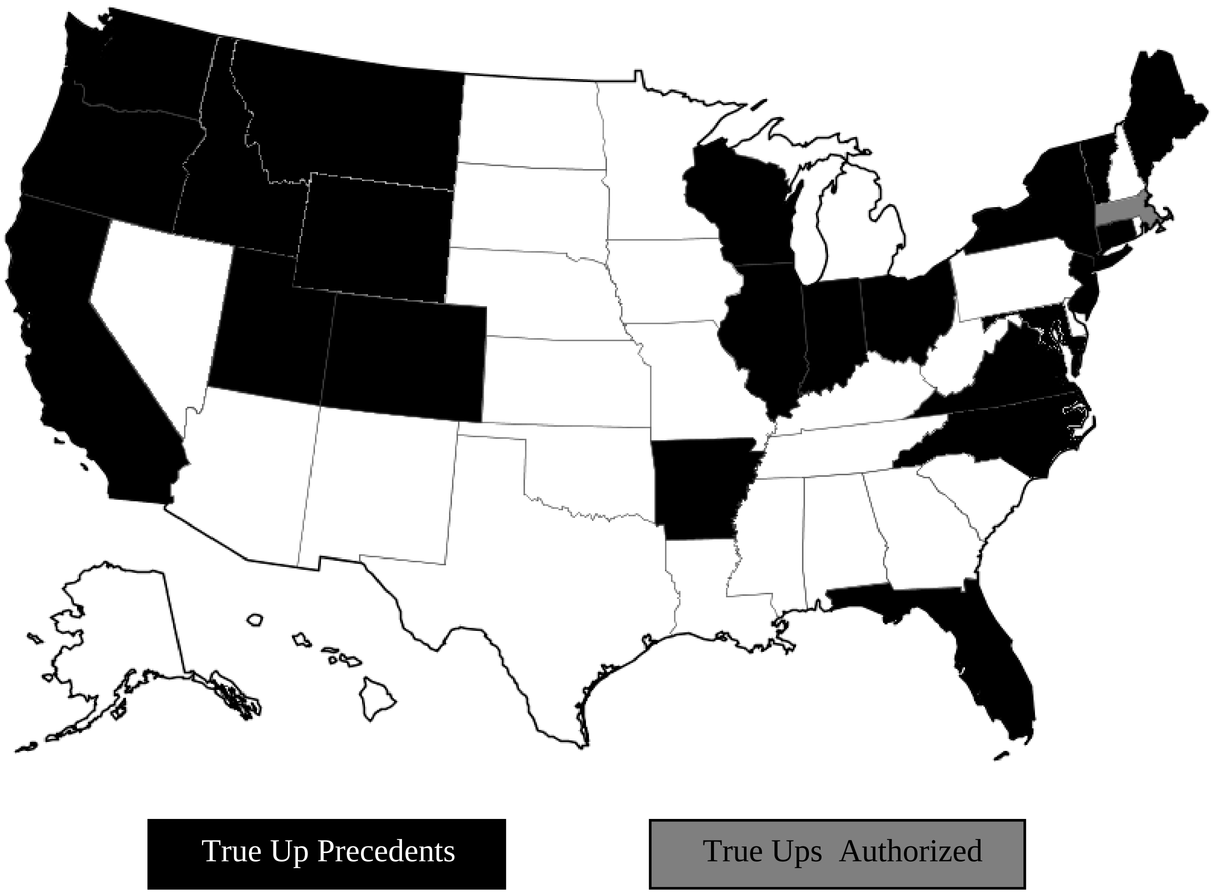
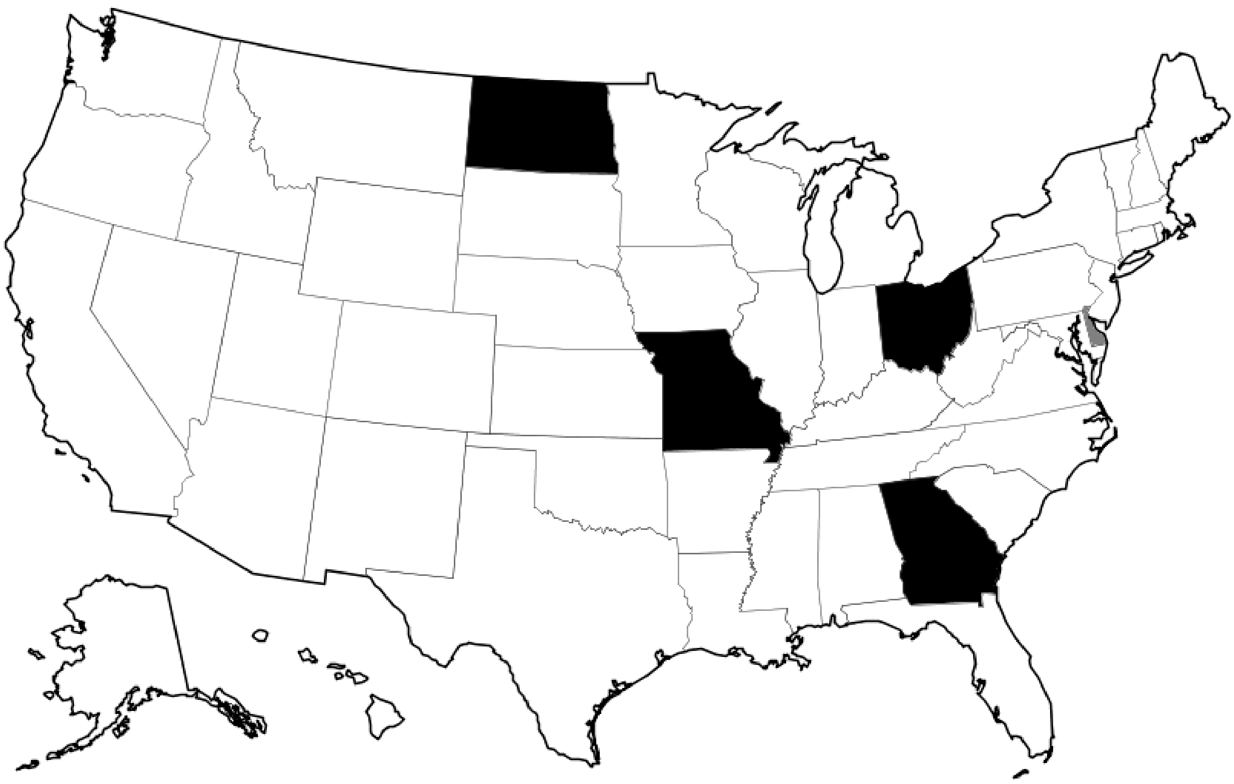


Figure 2: U.S. Decoupling Precedents by State:
SFV Pricing



SFV Precedents

SFV Authorized

III. APPRAISING ALTERNATIVE DECOUPLING APPROACHES

Q. What criteria are germane for determining which approach to decoupling is most sensible?

I believe that the relevant criteria include administrative simplicity, decoupling precedents, and the extent to which disincentives for the many avenues for encouraging efficient system use are removed. The other repercussions of a particular decoupling method should also be considered.

Q. Please compare the administrative simplicity of the two decoupling approaches.

The trueup approach to decoupling involves calculations that are relatively straight-forward provided that decoupling extends to all kinds of demand fluctuations[10]. The administrative cost of full decoupling trueups is not much different than the cost of other widely used trackers, including fuel adjustment clauses ("FACs"). In each case, the appropriate revenue requirement adjustment must first be ascertained and then allocated to service classes and recovered through rates. Decoupling trueup plans can actually *reduce* the net cost of regulation to the extent that they reduce the importance of lost margin calculations and of demand forecasts in rate cases and reduce the frequency of rate cases.[11] The Oregon Public Utilities Commission stated in its order approving the first decoupling trueup plan for Portland General Electric ("PGE") that "it is a relatively

[10] In addition to its low administrative cost, full decoupling encourages effective rate designs, as we discuss further below.
[11] Hawaiian Electric recently estimated in response to an information request in its decoupling proceeding that the annual amortization cost of a rate case ranges from $510,000 to $774,000 whereas under a decoupling trueup mechanism it ranges from $37,000 to $93,000.

simple mechanism to remove a variety of perverse incentives inherent in the existing structure of rate regulation and it has low administrative costs".[12]

Q. How about SFV Pricing?

Once SFV prices are established there is no need for supplemental annual rate adjustments of any kind to effect decoupling. However, SFV pricing does not by itself provide the basis for utilities to commit to multiyear rate plans under normal operating conditions. Hence, a multiyear decoupling true up plan with the right kind of RAM can have a lower *overall* regulatory cost.[13]

Q. Please discuss the impact of decoupling on the scale and effectiveness of EE programs.

Evidence on the scale of EE programs must be treated with caution in an appraisal of alternative decoupling mechanisms. The scale of *utility* programs depends, in addition to the decoupling mechanism chosen, on other conditions such as statutory mandates, the program cost recovery provisions, the character of supplemental incentives for utility EE programs, and on whether some EE programs are pursued by independent agencies. The scale of independent EE programs is relevant to an appraisal of decoupling anyways since it may reflect the degree to which a utility resists a large program that is run by an independent agency. This is not a minor matter since independent programs are often funded out of utility rates. It makes sense, then, to consider the scale of programs irrespective of whether they are offered by utilities.

---

[12] Order No. 95-322 March 1995, p. 4.
[13] The cost of SFV pricing could, however, be further reduced with a multiyear price cap plan.

The American Council for an Energy Efficient Economy ("ACEEE") recently issued a report on a study that ranks states in terms of the overall scale and effectiveness of EE programs[14]. Five states in which most EE programs were run by independent agencies were considered in the study along with states in which most programs were undertaken by utilities. Here are some salient results.

- California had the number one ranking in the survey for both natural gas and electric EE programs.

  Including California, six of the seven states with the highest-rated electric EE programs (California, Connecticut, Wisconsin, New York, Oregon, and Vermont) now have at least one electric utility decoupling trueup plan. The other state in the top 7, Massachusetts, is in the process of implementing decoupling for all electric utilities. Rhode Island ranked thirteenth in the study.

- The state of Maine has an independent DSM program administrator but does *not* have decoupling. Maine was not ranked in the ACEEE top 14.

- Including California, seven of the ten states with the highest-rated *gas* EE programs (California, Wisconsin, New York, Oregon, New Jersey, Vermont, and Washington) have at least one decoupling trueup plan for a gas utility. Of the other three states in the top 10, Massachusetts and Connecticut are in the process of implementing decoupling for all utilities. Rhode Island was not ranked in the top thirteen.

While decoupling is a recent development in some of these states, we can conclude that states that make large expenditures on EE increasingly view decoupling as a necessary part of the regulatory system.

Q. Please discuss the importance of rate design in the context of decoupling.

[14] Martin Kushler, Dan York, and Patti Witte, "Meeting Aggressive New State Goals for Utility-Sector Energy Efficiency: Examining Key Factors Associated With High Savings", ACEEE Report No. U091, March 2009.

The design of rates is a function typically retained by the utility whether or not it is responsible for administering EE programs. Rate design has a critically important impact on customer incentives to reduce power purchases because it affects the payback period on investments needed to reduce purchases. EE and customer-sited DG are encouraged by high volumetric charges. Time of use ("TOU") and other forms of peak load pricing --- for energy charges and base rates alike --- tend to discourage peak system use and encourage development of customer-sited solar resources.

Customers are not encouraged to make efficient use of the electric system unless usage charges reflect the full long run marginal cost to society of system use. The marginal cost of electric system use varies by time of day and can also vary seasonally. The marginal cost also includes the environmental damage created by central generating stations. Efficient prices should therefore vary by time of day and volumetric charges should ideally have a floor that is commensurate with the marginal environmental damage. Absent power prices that properly reflect this damage, base rates can be used for this purpose. Any overrecovery of cost that might result from such rate designs can be reduced by lower customer charges and/or inverted block rates. Inverted block rates are also useful as a substitute for peak load pricing where AMI is unavailable. The basic idea is that each incremental block of a customer's purchases is more likely to occur in peak load periods.

Q. How can decoupling promote efficient rate designs?

Peak load pricing and inverted block rates add to a utility's revenue risk in two ways. Revenue is more sensitive to demand fluctuations, and reduced system use over time is encouraged. A trueup mechanism eliminates both of these risks to the extent that there is full decoupling. In other words, trueups for fluctuations in demand due to weather and other business conditions remove an important disincentive for utilities to offer rate designs that encourage efficient system use.

Q. Are your conclusions recognized by other regulation authorities?

Yes. The potential of base rate design to encourage efficient system use has been recognized by prominent advisors to regulatory commissions. For example, the Regulatory Assistance Project ("RAP") states in a 2008 report on decoupling to Minnesota's PUC that

> a zero or minimum customer charge allows the bulk of a utility's revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental costs[15].

This report offers many other insights on decoupling and is attached to this testimony as Schedule EERMC-MNL-2.

As for the ability of decoupling to facilitate efficient rate designs the RAP states that

> Decoupling should remove traditional utility objections to electric and natural gas rate designs which encourage energy conservation, voluntary curtailment, and peak load management.[16]

The report goes on to say that

[15] Wayne Shirley, Jim Lazar, and Frederick Weston, "Revenue Decoupling: Standards and Criteria", regulatory Assistance Project, June 2008, p. 18.
[16] *Ibid*, p. 16.

> Revenue stability needs of the company can conflict with principles of cost causation as they relate to customers…To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage and LNG facilities) and those capacity costs are allocated exclusively to excess use in winter and summer months, the cost to consumers of excess usage is dramatically higher than the cost of base usage. A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage that requires that capacity. While this is arguably "fair", doing so can result in serious revenue stability issues for the utility. Decoupling is one way to address the revenue stability issue for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.[17]

Q. Please evaluate the SFV approach to decoupling in the light of this discussion.

Absent AMI, SFV recovers all fixed cost through customer charges. This does not send the right price signals to customers regarding purchase volumes or peak system use. The National Regulatory Research Institute (NRRI) writes that "the problem with SFV is that it reduces the variable charge to short-term variable cost, which is likely to be lower than the economically efficient level of long-term marginal cost, leading to overconsumption"[18] In addition to the detrimental efficiency impact, this reduces the economic opportunities of venders of EE and DG services. Customers lose the ability to control their bills. While it is sometimes argued that power prices provide customers with enough incentive to reduce purchases, these prices do not yet properly reflect the cost of environmental damage and, in any event, have fallen from their recent highs.[19]

---

[17] *Ibid*, p. 17.

[18] David Magnus Boonin, "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements", National Regulatory Research Institute, 2008.

[19] The natural gas pipeline industry of the United States provides an illustration of how SFV pricing for recovery of a utility's fixed costs materially promotes energy purchases despite customer exposure to volumetric energy charges. The FERC had long viewed cuts in pipeline volumetric charges as a means to increase the competitiveness of natural gas vis a vis coal. In adopting SFV pricing for all pipelines in 1992,

Q. Are there other problems with SFV pricing?

Yes. SFV pricing can also raise issues of rate fairness. The revenue requirement for residential and small commercial customers is usually recovered through high customer charges that are the same for all customers in the class. Assuming that larger volume customers in these service classes do not have unusually high load factors, however, they should pay *more* for system use and the associated environmental damage than smaller volume customers such as apartment dwellers.

A related problem with SFV pricing is that rapid implementation can produce sharp increases in bills for small-volume customers. Sharp increases in the bills of residential customers are occurring in Ohio where SFV pricing is being rapidly phased in by several gas utilities.

Q. Have regulators recognized these problems?

Yes. The Connecticut DPUC recognized these disadvantages of SFV pricing in approving a decoupling trueup plan for United Illuminating.

> UI will be assured of its revenue recovery. As a result, UI should be indifferent as to whether its revenues are collected through fixed charges, energy-based charges, or a combination of these rates. UI's proposal relies on a kWh-based decoupling mechanism instead of increases in fixed costs. This allows UI to maintain higher kWh charges which will provide customers with energy-based price signals…This in turn eliminates the Departments concern regarding the bill impacts associated with fixed cost recovery on low use customers. This also addresses the objections raised

---

there is little doubt that they contemplated further gains in system use. They stated that "the Commission's adoption of SFV should *maximize pipeline throughput* over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change" (emphasis supplied). See FERC Order No. 636 Final Rule, p. 129, April 1992.

> by the OCC and Environment Northeast as to the anticonservation potential associated with fixed cost recovery of distribution revenues.[20]

Q. Please discuss the implications of your rate design perspective for backup rates for customers with distributed generation

The efficient level of DG depends on getting usage charges right. A customer of a power distributor considering DG in an optimal pricing world would face some kind of peak load pricing for power and delivery services. Energy charges would, additionally, reflect the full environmental cost of fossil fueled generation. DG would have the appeal of radically reducing these charges. A high fixed charge or standby charge designed to ensure recovery of system cost from a DG customer irrespective of system use can discourage efficient DG. Decoupling can remove the disincentive to offer DG customers efficient prices.

Q. Is there evidence that decoupling trueup plans encourage innovative pricing?

Yes. Utilities operating under revenue decoupling are often leaders in rate design. I will limit the focus of my discussion to inverted block rates. In California, inverted block rates have been mandated for small volume customers without TOU meters since the 1970s. The decision approving the first decoupling plan for Southern California Edison stated that "the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation *and rate design policies* enunciated by this Commission" (emphasis supplied).[21]

[20] *Ibid*, p. 123.
[21] D. 82-12-055 (1982) p. 17.

All three major California electric utilities are in the process of implementing systemwide AMI. Pending the completion of this effort, small volume customers face inverted block rates for base rate inputs. For example, a typical residential customer of PG&E's *distribution* services faces a low $3.58 minimal monthly bill and 5 tiers of volumetric charges ranging from $ 0.037/kWh for the lowest tier to $ 0.16/kWh for the highest tier. Remarkably, residential TOU prices also involve inverted block rates.

California was also the early bird in the implementation of decoupling for natural gas utilities. Helping gas companies cope with the risk of inverted block rates was an important motivation for the decoupling plan. Inverted block rates are still common for California gas utilities and are otherwise rare in the US gas distribution industry. The state has, more recently, become a national leader in decoupling for water utilities. Inverted block rates play a central role in the conservation programs of participating utilities.

Q. Please discuss how decoupling has encouraged innovative rate designs in other states.

In Idaho, the Commission recently approved a three tier, year around inverted block rate structure for most residential customers[22]. The Commission also approved year round inverted block rates for the small general service customers covered by decoupling. Staff identified these tiered rates as a "reasonable surrogate for time of use rates that send customers a message to use energy efficiently".

[22] Most residential customers previously faced a two tier increasing block rate structure with a very gradual inversion in the summertime.

In Oregon, residential customers of PGE face inverted block rates. The company commented in its rate design testimony that "absent our decoupling proposal, we would advocate for higher customer charges to reduce the impact of recovering fixed distribution costs on a volumetric basis"[23].

In Wisconsin, a reduction in residential customer charges (*e.g.* from $8.40 to $5.70 for single phase service) was part of the Citizens Utility Board's settlement with Wisconsin Public Service. The decoupling plan also includes the development and implementation of three community based pilot programs that include "innovative rate offerings that increase opportunities for customers to use energy more efficiently". One of these programs will include AMI.

Q. What conclusions do you draw from this discussion of rate design?

Rate design is an important means by which utilities influence efficient system use, including EE and DG. The trueup approach to decoupling has a major advantage over the alternative approaches as a means for encouraging efficient rate design --- especially in the absence of AMI. The utility must be protected from the risk of demand fluctuations from a wide range of sources, but this facilitates rate designs, such as inverted block rates, that encourage efficient system use and avoid high customer charges

Q. Please discuss how decoupling influences appliance standards and building codes

[23] Direct Testimony of Doug Kuns and Marc Cody in UE 197, February 2008.

A utility operating without broad-based decoupling has incentives between rate cases to resist changes in appliance standards, building codes, and other public policies that encourage EE. Stringent standards in states with decoupling may reflect the acquiescence or active support of utilities. Decoupling agreements sometimes contain utility commitments to support efficiency standards.

Q. Can you provide some examples?

Yes. California has been a national leader in the establishment of policies outside the regulatory arena that promote energy efficiency. The state has a separate commission [the California Energy Commission ("CEC")] to monitor and regulate key aspects of the energy economy. This includes the establishment and enforcement of EE standards for buildings and appliances. A CEC study has found that conservation due to appliance and energy efficiency standards has grown substantially since the institution of decoupling and now accounts for more than half of the accumulated energy savings since 1980. In the aftermath of the power crisis, and following the resumption of decoupling pursuant to a 2001 statute, California instituted an *Energy Action Plan* in 2003 that has been periodically updated. The plan features aggressive new measures to promote energy efficiency and demand response.

Wisconsin Public Service agreed in its decoupling settlement with the Citizens Utility Board to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force addressing

- residential and commercial energy efficient building codes,

- state appliance efficiency standards, and
- nonregulated fuels efficiency and conservation.

Q. Please discuss how decoupling influences policies towards solar DG.

The Network for Energy Choices released a study in 2009 that ranked states on policies to promote solar energy[24]. The focus of the study was net metering policy and interconnection standards. In this study, California ranked only seventh, garnering a "B grade" for both net metering and connections.

However, the study did not consider subsidies and other policies, for which California is noted, that promote development of customer-sited solar resources. The California PUC implemented a California Solar Initiative for major investor-owned electric utilities in 2006. It provides upfront incentives for solar systems installed on customer premises. Customer-sited photovoltaic (PV) generation capacity has grown rapidly in the state in recent years, pushing against current net metering limits. The Solar Water Heater and Heating Efficiency Act of 2007 has introduced a new rebate program for solar water heating. All three large California utilities are now required to offer feed in tariffs on an experimental basis. The companies have opposed an expansion of the net metering cap until a study of its effects is completed.

I contacted authors of the *Freeing the Grid* study to ask how California ranked with regard to its overall support for solar energy. One responded by e mail that

[24] James Rose *et al*, *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Standards*, Network for New Energy Choices, October 2008.

> CA has been at the top of the U.S. state solar heap for many years, primarily due to strong public policy efforts and funding commitments. CA blows the rest of the states away in terms of number and capacity of installed solar-energy systems. There is no publication that rates states on overall policy efforts to promote solar. But if there were, and especially if the study took into account policies implemented during the last 10 years, CA would very likely take the top slot. Other states are catching up, but this will take a long time.

Another responded "for subsidies, I'd say that CA is far beyond any other state in the nation."

Even though the Hawaii Commission has not yet approved revenue decoupling for the Hawaiian Electric Companies, it is noteworthy that the Energy Agreement commits the companies to an aggressive program of support for the development of customer sited solar resources. These include support for a continuation of solar water heating tax rebates, a solar water heating "pay as you save" program, feed-in tariffs, net metering at time of use pricing, and a PV Host program.

Q. Please discuss how decoupling influences other promotional measures

Other measures that utilities can take to promote efficient system use include advertising, bill inserts, and cooperation with independent energy service providers. Few studies have endeavored to examine the possible effects of decoupling on these promotional measures. One of the best was an independent appraisal of the decoupling plan, called the Distribution Margin Normalization ("DMN"), of Northwest Natural Gas in Oregon. The authors, who recommended the continuation of decoupling, state that

> We have been impressed by the breadth of support that DMN has received. The Energy Trust of Oregon reports that NW Natural has been

> successful in creating a good working relationship with the Energy Trust, and that NW Natural's efforts to promote energy efficiency effectively complement their own efforts. HVAC distributors believe that NW Natural's marketing efforts, in conjunction with its relationships with consumers, distributors, and the Energy Trust have helped increase sales of high-efficiency furnaces to the point where Oregon has the highest share of high-efficiency furnaces in the nation (as a percentage of new furnace sales). The Citizens' Utility Board of Oregon, the Northwest Energy Coalition and a number of CAP agencies believe that the Public Purposes Funding established in conjunction with the DMN is beneficial for consumers. The Natural Resources Defense Council and American Gas Association released a joint statement regarding the positive environmental effects of decoupling, specifically citing NW Natural's experience as an example of the positive outcomes that decoupling can yield[25].

Q. What are some of the other repercussions of decoupling approaches that should be considered?

One important issue is rate and revenue stability. This issue is often discussed in debates about decoupling but is not widely understood. SFV pricing stabilizes base rate revenue by reducing reliance on volumetric charges. Decoupling true up plans stabilize base rate revenue insofar as they constrain it to the gradual growth of the revenue requirement. In each case, customer bills are also stabilized[26]. This is a matter of *mutual* risk reduction and not of a shifting of risk from the customer to the Company[27].

Decoupling true ups and SFV pricing do differ with regard to rate stability. In the case of true up plans, greater stability of bills involves greater instability in *rates*. However, experience has shown that this problem is manageable. A study of the first decade of

[25] Daniel Hanson and Steve Braithwait, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005.

[26] Decoupling provides further stability to customer expenditures to the extent that it reduces reliance on power from the New England market.

[27] In contrast, an energy cost adjustment clause shifts the risk of energy price volatility from utilities to customers. Utilities have more stable earnings and customers have less stable prices and bills.

California decoupling plans reveals that price volatility was generally not pronounced[28]. In New York, the reconciliations ranged from a 0.2% decrease to a 2% increase but some reconciliations were capped[29] Another study, prepared for the National Resources Defense Council, has reached the same finding for more recent decoupling plans[30]. In the latter study, rate adjustments were reported to be typically less than 2% and only rarely in excess of 5%. Rate adjustments produced by purchased gas adjustment and fuel and purchased power adjustment clauses tend to be much larger.

Studies have also found that adjustments were positive nearly as often as they were negative. Weather tends to be the primary cause of rate adjustments. The rate volatility problem is nonetheless of concern to some regulators. This can be addressed, without weakening performance incentives, by a "soft" cap on the size of rate adjustments that defers balances that exceed the cap for future collection with interest.

Q. What conclusions should be drawn from this discussion concerning the best approach to revenue decoupling?

The discussion permits us to draw a number of conclusions. Decoupling can remove utility disincentives to promote efficient EE, peak system use, and customer-sited DG. When delivery volumes per customer are trending downward, the frequency of rate cases can be reduced. This encourages better utility operating performance and frees

[28] Joseph Eto, Steven Stoft, and Timothy Beleden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, 1994.
[29] James T. Gallagher, "Revenue Decoupling: New York's Experience and Future Directions", NARUC 2007 Summer Committee Meetings, July 2007.
[30] Pamela Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review", June 2009.

regulatory resources to focus on other issues. Benefits of reduced risk can be shared with customers in the form of a lower target rate of return.

Utilities have at their disposal various measures to promote efficient use of their systems. These include rate design, support for improved building codes and appliance efficiency standards, and measures to facilitate development of customer-sited renewables. Decoupling is most effective when it removes disincentives for utilities to use all of the "arrows in the quiver". The traditional true-up approach to decoupling is the best practice approach because it combines reasonable administrative cost with an ability to encourage an especially wide range of promotional measures.

These advantages of the true up approach to decoupling help to explain why it is becoming the norm in states that are strongly committed to goal of efficient system use. The Oregon PUC, in approving a true up plan for Portland General Electric ("PGE") in 1995, stated that

> because decoupling separates profits from fluctuating sales levels, regardless of the cause of the changed sales, it addresses efficiency impacts resulting from *all* affects, including rate design, all utility-sponsored demand-side management activities, and all energy efficiency measures.[31] (emphasis in original?)

A review of experience with the true up approach to decoupling suggests that it does encourage a wide range of promotional measures. The primary example in support of this proposition is California, which has the most extensive experience with decoupling trueups and is a national leader not only in gas and electric EE programs but with respect

[31] OR95-0322, March 1995, p. 15.

to appliance efficiency standards and building codes, rate designs, and the promotion of customer-sited solar resources.

IV. APPLICATION TO RHODE ISLAND

Q. How would you use your analysis to develop a recommendation as to where decoupling should be implemented?

My discussion suggests that a trueup decoupling mechanism is advantageous in jurisdictions in which some or all of the following conditions hold.

- State policymakers are committed to the goal of efficient electric system use, including EE, DG, and peak load use.
- There are substantial opportunities to improve the efficiency of system use.
- The utility has the potential to influence efficient system use.
- Deliveries per customer are stagnant or expected to decline.
- Rate designs that encourage efficient system use are accepted and encouraged
- Demand is hard to forecast
- Prices in the bulk power market are volatile
- Central generating stations in the region damage the environment
- Central generating stations in the region burn petroleum fuels
- Decoupling is sanctioned by the regulatory commission and/or state law

It is important to reiterate that decoupling can be desirable even when all of these conditions do not hold to the fullest extent possible.

Q. Please consider the extent to which these conditions exist in Rhode Island.

Consider first that the state of Rhode Island is strongly committed to fostering efficient electric system use.

- Pursuant to the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006, Section 39-1-27.7 of Rhode Island's General Laws identifies EE, customer-sited DG, peak system use and supply procurement as "complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost effective, reliant, prudent and environmentally responsible". This makes utility promotion of EE, DG, and peak system savings that have a lower cost than supply options a part of the standard of operating prudence.

- Chapter 39-26 of the Rhode Island General Laws has established a renewable energy standard, and power production from off-grid and customer-sited generation facilities can be counted by Grid in compliance.

- H. 5461 provides various encouragements to customer-sited renewable resources, including an increase in the net metering cap to 2%.

Q. Is there evidence that there are opportunities to improve the efficiency of electric system use?

Yes. The EERMC commissioned studies on the opportunities for EE and customer-sited DG in Rhode Island. It issued a report on this research in July 2008.[32] The report noted that opportunities for incremental gains are substantial, most notably in the areas of EE and CHP.

Q. Is National Grid in a position to promote energy efficiency?

Very much so. National Grid is responsible for a significant amount of EE in Rhode Island. The Company must obtain approval of periodically updated Energy Efficiency and System Reliability Procurement Plans. National Grid nonetheless has substantial discretion in the design and implementation of its promotional measures. For example,

[32] EERMC, "Opportunity Report – Phase I", July 2008

the budget for EE programs is not fixed and can be supplemented from distribution rates. The plan for the next three years has been approved but the Company has great discretion with regard to implementation details. Work will, in any event, commence on a new plan in 2011. There are, additionally, many other ways in which the Company can encourage efficient system use, including better rate designs, the installation of AMI, and policies towards customer-sited DG.

Q. Does a decline in volumes per customer seem likely to be a problem for National Grid?

Yes. Last March, the Company secured approval of a three year plan for energy efficiency and system reliability procurement. This involves a doubling of the Company's already sizable EE program expenditures and is expected to double EE savings from 2008 to 2011. Other factors are also promoting efficient system use, including Federal legislation such as the Energy Independence and Security Act of 2007. Under these conditions, the trend in the volume/customer of National Grid's power deliveries to residential and commercial customers is likely to be stagnant or declining for the foreseeable future. Since the Company currently gathers a high percentage of its base rate revenue through volumetric and other usage charges there will be increased financial attrition between rate cases. In the absence of decoupling, Grid will likely respond to this challenge by requesting higher fixed charges, filing rate cases more frequently, and/or by reducing its vigor in promoting efficient electric system use.

Q. Which characteristics of the New England power market are germane to National Grid's decoupling proposal?

Power prices are volatile in New England. A sizable share of power supplies are drawn from coal and oil fired central generating stations. New England is also experiencing brisk growth in transmission cost. These conditions increase the appeal of reducing reliance on the electric system.

Q. Please discuss the company's rate designs

National Grid is not a leader in AMI for residential or small C&I customers and does not offer inverted block rates to customers who lack it. Decoupling would remove disincentives to experiment with inverted block rates and/or to move more aggressively to introduce AMI. The Company does have comparatively low customer charges and gathers a sizable share of its revenue from volumetric charges.

Q. Do Rhode Island laws and regulation permit decoupling?

Yes. State legislation authorizes the Commission to approve and even to mandate a decoupling trueup plan. Section 39-1-27.7 (d) of the General Laws states that

> if the commission shall determine that the implementation of system reliability and energy efficiency and conservation procurement has caused or is likely to cause under or over-recovery of overhead and fixed costs of the company implementing said procurement, the commission may establish a mandatory rate adjustment clause for the company so affected in order to provide for full recovery of reasonable and prudent overhead and fixed cost.

It is important to note that under-recoveries and over-recoveries due to weather and local economic activity are difficult to remove from the decoupling mechanism and their decoupling advances state policy goals to the extent that rates are designed to promote them.

Q. What conclusions do you draw about the desirability of decoupling for the electric services of National Grid?

The degree to which these conditions that favor revenue decoupling exist today in Rhode Island is clearly striking. On balance, I therefore conclude that a revenue decoupling true up plan --- which is the best practice approach to decoupling --- is desirable for Rhode Island.

Q. Please comment on Grid's specific decoupling proposal.

National Grid is proposing a decoupling true-up mechanism in this proceeding. This will remove disincentives for a wide range of actions to promote efficient system use at a reasonable administrative cost. Grid also proposes a RAM and this has also been noted to be the common practice.

As for commitments offered in return for the approval of decoupling, the company already has a plan for a major increase in EE programs. In conformance with state policy, this plan was approved before the start of the proceeding and approval of decoupling was contemplated when the plan was conceived. Company witness Stout notes that the plan was prepared in the expectation of the approval of a decoupling mechanism.[33]

[33] Stout Testimony, p. 11

Q. Does the Company make any supplemental commitments if the decoupling plan is approved?

Not many. Witness Stout hints at the possibility that EE spending could be further expanded if additional funds are available[34]. DG customers who are currently taking the Rate B-23 backup service may be moved to the same Rate G-32 taken by other high-demand customers.

National Grid can broaden support for decoupling by making more definite commitments with regard to changes in EE programs and standby rates that would be implemented if decoupling is approved. The Company should also consider supplemental commitments in such areas as rate design, appliance efficiency standards and building codes, and support for DG. The EERMC can and should help to ensure that any such commitments serve the public interest.

Q. Based on your experience, do you recommend that the Commission adopt National Grid's true-up mechanism?

Yes. As I've discussed in this testimony, a true-up mechanism that accounts for all changes in a utility's sales is the most appropriate decoupling mechanism for Rhode Island. National Grid has proposed a mechanism that achieves these goals, and its mechanism should be adopted.

Q. Does this conclude your testimony?

Yes it does.

[34] Stout Testimony, p. 11-12.

Resume of

MARK NEWTON LOWRY

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address 22 E. Mifflin St., Suite 302
Madison, WI 53703
(608) 257-1522 Ext. 23

Education BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive of the research unit of the PEG consortium. Leads internationally recognized practice in the field of statistical cost research for energy utility benchmarking and alternative regulation ("Altreg"). Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group LLC, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.
8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.

12. Workshop on PBR for Electric Utilities. Southern Company Services, 1991.
13. Economics of Electric Revenue Adjustment Mechanisms. Niagara Mohawk Power, 1991.
14. Sales Promotion Policies of Gas Distributors. Northern States Power-Wisconsin, 1991.
15. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in PBR. Southern California Gas, 1991.
16. Cost Performance Indexes for Gas and Electric Utilities. Niagara Mohawk Power, 1991.
17. Efficient Rate Design for Interstate Gas Transporters. AEPCO, 1991.
18. Benchmarking Gas Supply Services and Testimony. Niagara Mohawk Power, 1992.
19. Gas Supply Cost Indexes for Incentive Regulation. Pacific Gas & Electric, 1992.
20. Gas Transportation Strategy for an Arizona Electric Utility. AEPCO, 1992.
21. Design and Negotiation of a Comprehensive Benchmark Incentive Plans for Gas Distribution and Bundled Power Service. Niagara Mohawk Power, 1992.
22. Productivity Research, PBR Plan Design, and Testimony. Niagara Mohawk Power, 1993-94.
23. Development of Incentive Regulation Options. Southern California Edison, 1993.
24. Review of the Southwest Gas Transportation Market. Arizona Electric Power Cooperative, 1993.
25. Productivity Research and Testimony in Support of a Price Cap Plan. Central Maine Power, 1994.
26. Productivity Research for a Natural Gas Distributor, Southern California Gas, 1994.
27. White Paper on Price Cap Regulation For Electric Utilities. Edison Electric Institute, 1994.
28. Statistical Benchmarking for Bundled Power Services and Testimony. Southern California Edison, 1994.
29. White Paper on Performance-Based Regulation. Electric Power Research Institute, 1995.
30. Productivity Research and PBR Plan Design for Bundled Power Service and Gas Distribution. Public Service Electric & Gas, 1995.
31. Regulatory Strategy for a Restructuring Canadian Electric Utility. Alberta Power, 1995.
32. Incentive Regulation Support for a Japanese Electric Utility. Tokyo Electric Power, 1995.
33. Regulatory Strategy for a Restructuring Northeast Electric Utility. Niagara Mohawk Power, 1995.
34. Productivity and PBR Plan Design Research and Testimony for a Natural Gas Distributor. Southern California Gas, 1995.
35. Productivity Research and Testimony for a Natural Gas Distributor. NMGas, 1995.
36. Speech on PBR for Electric Utilities. Hawaiian Electric, 1995.
37. Development of a Price Cap Plan for a Midwest Gas Distributor. Illinois Power, 1996.
38. Stranded Cost Recovery and Power Distribution PBR for a Restructuring U.S. Electric Utility. Delmarva Power, 1996.
39. Productivity and Benchmarking Research and Testimony for a Natural Gas Distributor. Boston Gas, 1996.
40. Consultation on the Design and Implementation of Price Cap Plans for Natural Gas Production, Transmission, and Distribution. Comision Reguladora de Energia (Mexico), 1996.
41. Power Distribution Benchmarking for a PJM Utility. Delmarva Power, 1996.
42. Testimony on PBR for Power Distribution. Commonwealth Energy System, 1996.
43. PBR Plan Design for Bundled Power Services. Hawaiian Electric, 1996.
44. Design of Geographic Zones for Privatized Natural Gas Distributors. Comision Reguladora de Energia (Mexico), 1996.
45. Statistical Benchmarking for Bundled Power Service. Pennsylvania Power & Light, 1996.
46. Productivity Research and PBR Plan Design (including Service Quality) and Testimony for a Gas Distributor. BC Gas, 1997.

47. Price Cap Plan Design for Power Distribution Services. Comisión de Regulación de Energía y Gas (Colombia), 1997.
48. White Paper on Utility Brand Name Policy. Edison Electric Institute, 1997.
49. Statistical Benchmarking for Bundled Power Service and Testimony. Pacific Gas & Electric, 1997.
50. Review of a Power Purchase Contract Dispute. City of St. Cloud, MN, 1997.
51. Statistical Benchmarking and Stranded Cost Recovery. Edison Electric Institute, 1997.
52. Inflation and Productivity Trends of U.S. Power Distributors. Niagara Mohawk Power, 1997.
53. PBR Plan Design, Statistical Benchmarking, and Testimony for a Gas Distributor. Atlanta Gas & Light, 1997.
54. White Paper on Price Cap Regulation (including Service Quality) for Power Distribution. Edison Electric Institute, 1997-99.
55. White Paper and Public Appearances on PBR Options for Power Distributors in Australia. Distribution companies of Victoria, 1997-98.
56. Research and Testimony of Gas and Power Distribution TFP. San Diego Gas & Electric, 1997-98.
57. Cost Structure of Power Distribution. Edison Electric Institute, 1998.
58. Cross-Subsidization Measures for Restructuring Electric Utilities. Edison Electric Institute, 1998.
59. Testimony on Brand Names. Edison Electric Institute, 1998.
60. Research and Testimony on Economies of Scale in Power Supply. Hawaiian Electric Company, 1998.
61. Research and Testimony on Productivity and PBR Plan Design for Bundled Power Service. Hawaiian Electric and Hawaiian Electric Light & Maui Electric, 1998-99.
62. PBR Plan Design, Statistical Benchmarking, and Supporting Testimony. Kentucky Utilities & Louisville Gas & Electric, 1998-99.
63. Statistical Benchmarking for Power Distribution. Victorian distribution business, 1998-9.
64. Testimony on Functional Separation of Power Generation and Delivery in Illinois. Edison Electric Institute, 1998.
65. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. Niagara Mohawk Power, 1998.
66. Workshop on PBR for Energy Utilities. World Bank, 1998
67. Advice on Code of Conduct Issues for a Western Electric Utility. Public Service of Colorado, 1999.
65. Advice on PBR and Affiliate Relations. Western Resources, 1999.
66. Research and Testimony on Benchmarking and PBR Plan Design for Bundled Power Service. Oklahoma Gas & Electric, 1999.
67. Cost Benchmarking for Power Transmission and Distribution. Southern California Edison, 1999.
68. Cost Benchmarking for Power Distribution. CitiPower, 1999.
69. Cost Benchmarking for Power Distribution. Powercor, 1999.
70. Cost Benchmarking for Power Distribution. United Energy, 1999.
71. Statistical Benchmarking for Bundled Power Services. Niagara Mohawk Power, 1999.
72. Unit Cost of Power Distribution. AGL, 2000.
73. Critique of a Commission-Sponsored Benchmarking Study. CitiPower, Powercor, and United Energy, 2000.
74. Statistical Benchmarking for Power Transmission. Powerlink Queensland, 2000.
75. Testimony on PBR For Power Distribution. TXU Electric, 2000.
76. Workshop on PBR for Gas and Electric Distribution. Public Service Electric and Gas, 2000.
77. Economies of Scale and Scope in an Isolated Electric System. Western Power, 2000.

78. Research and Testimony on Economies of Scale in Local Power Delivery, Metering, and Billing. Electric distributors of Massachusetts, 2000.
79. Service Quality PBR Plan Design and Testimony. Gas and electric power distributors of Massachusetts, 2000.
80. Power and Natural Gas Procurement PBR. Western Resources, 2000.
81. PBR Plan Design for a Natural Gas Distributor. BC Gas, 2000.
82. Research on TFP and Benchmarking for Gas and Electric Power Distribution. Sempra Energy, 2000.
83. E-Forum on PBR for Power Procurement. Edison Electric Institute, 2001.
84. Statistical Benchmarking for Power Distribution, Queensland Competition Authority, 2001.
85. Productivity Research and PBR Plan Design. Hydro One Networks, 2001.
86. PBR Presentation to Governor Bush Energy 2000 Commission. Edison Electric Institute, 2001.
87. Competition Policy in the Power Market of Western Australia, Western Power, 2001.
88. Research and Testimony on Productivity and PBR Plan Design for a Power Distributor. Bangor Hydro Electric, 2001.
89. Statistical Benchmarking for three Australian Gas Utilities. Client name confidential, 2001.
90. Statistical Benchmarking for Electric Power Transmission. Transend, 2002.
91. Research on Productivity and Benchmarking for Gas and Electric Power Distribution. Sempra Energy, 2002.
92. Research and Testimony on Benchmarking for Bundled Power Service. AmerenUE, 2002.
93. Research on Power Distribution Productivity and Inflation Trends. NSTAR, 2002.
94. Research and Testimony on Power and Natural Gas Distribution Productivity and Benchmarking. Sempra Energy, 2002.
95. Future of T&D Regulation. Southern California Edison, October 2002.
96. Research on the Incentive Power of Alternative Regulatory Systems. Hydro One Networks, 2002.
97. Workshop on Recent Trends in PBR. Entergy Services, 2003.
98. Workshop on PBR for Louisiana's Public Service Commission. Entergy Services, February 2003.
99. Research, Testimony, and Settlement Support on the Cost Efficiency of O&M Expenses. Enbridge Gas Distribution, 2003.
100. Advice on Performance Goals for a U.S. Transmission Company. American Transmission, 2003.
101. Workshop on PBR for Canadian Regulators. Canadian Electricity Association, 2003.
102. General consultation on PBR Initiative. Union Gas, 2003.
103. Statistical Benchmarking of Four Bolivian Power Distributors. Superintendencia de Electricidad, 2003.
104. Statistical Benchmarking of Power Transmission. Central Research Institute for the Electric Power Industry (Japan), 2003.
105. Statistical Benchmarking, Productivity, and Incentive Power Research for a Combined Gas and Electric Company. Baltimore Gas and Electric, 2003.
106. Advice on Statistical Benchmarking for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution, 2003.
107. Research, Testimony, and Settlement Support on the Cost Efficiency of O&M Expenses for a Canadian Gas Distributor. Enbridge Gas Distribution, 2004.
108. Research and Advice on PBR for a Western Gas Distributor. Questar Gas, 2004.
109. Research and Testimony on Power and Natural Gas Distribution Productivity and Benchmarking for a U.S. Utility. Sempra Energy, 2004.
110. Advice on Productivity for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution, 2004.

111. Workshop on Service Quality Regulation for Regulators. Canadian Electricity Association, 2004.
112. Advice on Benchmarking Strategy for a Canadian Trade Association. Canadian Electricity Association, 2004.
113. White Paper on Unbundled Storage and the Chicago Gas Market for a Midwestern Gas Distributor. Nicor Gas, 2004.
114. Statistical Benchmarking Research for a British Power Distributor. United Utilities, 2004.
115. Statistical Benchmarking Research for Three British Power Distributors. EDF Eastern, EDF London, and EDF Seeboard, 2004.
116. Benchmarking Testimony for Three Ontario Power Distributors. Hydro One, Toronto Hydro, and Enersource Hydro Mississauga, 2004.
117. Indexation of O&M Expenses for an Australian Power Distributor. SPI Networks, 2004.
118. Power Transmission and Distribution PBR and Benchmarking Research for a Canadian Utility. Hydro One Networks, 2004.
119. Statistical Benchmarking of O&M Expenses for an Australian Power Distributor. SPI Networks, 2004.
120. Testimony on Statistical Benchmarking of Power Distribution. Hydro One Networks, 2005
121. Statistical Benchmarking for a Southeastern U.S. Bundled Power Service Utility. Progress Energy Florida, 2005.
122. Statistical Benchmarking of a California Nuclear Plant. San Diego Gas & Electric, 2005.
123. Explaining Recent Rate Requests of U.S. Electric Utilities: Results from Input Price and Productivity Research. Edison Electric Institute, 2005.
124. Power Transmission PBR and Benchmarking Support and Testimony. Trans-Energie, 2005.
125. Power Distribution PBR and Benchmarking Research and Testimony. Central Vermont Public Service, 2006.
126. Research and Testimony on Productivity Trends in Electric and Gas Distribution for a California Electric Utility. San Diego Gas & Electric and Southern California Gas, 2006
127. Consultation on PBR for Power Transmission for a Canadian Transco. British Columbia Transmission, 2006.
128. White Paper on Alternative Regulation for Major Plant Additions for a U.S. Trade Association. EEI, 2006.
129. Consultation on Price Cap Regulation for Provincial Power Distributors. Ontario Energy Board, 2006.
130. Statistical Benchmarking of A&G Expenses. Michigan Public Service Commission, 2006.
131. Workshop on Alternative Regulation of Major Plant Additions. EEI, 2006.
132. White Paper on Power Distribution Benchmarking for a Canadian Trade Association. Canadian Electricity Association, 2006.
133. Consultation on a PBR Strategy for Power Transmission. BC Transmision, 2006.
134. Testimony on Statistical Benchmarking of Power Distribution. FortisAlberta, 2006.
135. Consultation on a Canadian Trade Association's Benchmarking Program. Canadian Electricity Association, 2007.
136. Gas Distribution Productivity Research and Testimony for a Canadian Regulator. Ontario Energy Board, 2007.
137. Testimony on Tax Issues for a Canadian Regulator. Ontario Energy Board, 2008.
138. Research and Testimony in Support of a Revenue Adjustment Mechanism for Central Vermont Public Service, 2008.
139. Consultation on Alternative Regulation for a Midwestern Electric Utility. Xcel Energy, 2008.

140. Research and Draft Testimony in Support of a Revenue Decoupling Mechanism for a Large Midwestern Gas Utility. NICOR Gas, 2008.
141. Research and Testimony in Support of Revenue Decoupling Mechanisms for 3 US Electric Utilities. Hawaiian Electric, 2008.
142. White Paper: Use of Statistical Benchmarking in Regulation. Canadian Electricity Association, 2005-2009.
143. Statistical Cost Benchmarking of Canadian Power Distributors. Ontario Energy Board, 2007-2009.
144. Statistical Benchmarking for a Midwestern Electric Utility. Oklahoma Gas & Electric, 2009.

Publications

1. "Public vs. Private Management of Mineral Inventories: A Statement of the Issues." Earth and Mineral Sciences 53, (3) Spring 1984.
2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. "The Changing Role of the United States in World Mineral Trade." ed W.R. Bush, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. "Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect." Materials and Society 10 (3), 1986.
5. "Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products" (with junior author Bok Jae Lee) John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. "Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans" (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November, 1987.
7. "Storage, Monopoly Power, and Sticky Prices." Les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. "Review of Oil Prices, Market Response, and Contingency Planning." George Horwich and David Leo Weimer (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
10. "A Competitive Model of Primary Sector Storage of Refined Oil Products." July 1987, Resources and Energy 10 (2) 1988.
11. "Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil." Energy Economics 10 (4) 1988.
12. "Speculative Stocks and Working Stocks." Economic Letters 28 1988.
13. "Theory of Pricing and Storage of Field Crops With an Application to Soybeans" [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. "Competitive Speculative Storage and the Cost of Petroleum Supply." The Energy Journal 10 (1) 1989.
15. "Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric." In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute,1991).
16. "Futures Prices and Hidden Stocks of Refined Oil Products." In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. "Indexed Price Caps for U.S. Electric Utilities." The Electricity Journal, September-October 1991.

18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. "The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann)." Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.
23. "Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann)." AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. "Price Caps for Distribution Service: Do They Make Sense?" (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
33. "Econometric Cost Benchmarking of Power Distribution Cost" " (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
34. "Alternative Regulation for North American Electric Utilities" (with Lawrence Kaufmann), Electricity Journal, July 2006.
35. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
36. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
37. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
38. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods" (with Lullit Getachew), Energy Policy, 2009.

39. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), forthcoming in the International Handbook on the Economics of Energy.
40. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), USAEE Dialogue, August 2009.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans, LA, March 1986
2. International Association of Energy Economists, Calgary, AL, July 1987
3. American Agricultural Economics Association, Knoxville, TN, August 1988
4. Association d'Econometrie Appliqué, Washington, DC, October 1988
5. Electric Council of New England, Boston, MA, November 1989
6. Electric Power Research Institute, Milwaukee, WI, May 1990
7. New York State Energy Office, Saratoga Springs, NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus, OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg, VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell, MT, May 1994
12. Edison Electric Institute, Washington, DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando, FL, March 1995
14. Illinois Commerce Commission, St. Charles, IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco, CA, April 1996
18. AIC Conferences, Orlando, FL, April 1996
19. IBC Conferences, San Antonio, TX, June 1996
20. American Gas Association, Arlington, VA, July 1996
21. IBC Conferences, Washington, DC, October 1996
22. Center for Regulatory Studies, Springfield, IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton, AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving, TX, Sept. 1997
27. American Gas Association, Washington, DC [national telecast], September 1997
28. Infocast, Miami Beach, FL, Oct. 1997
29. Edison Electric Institute, Arlington, VA, March 1998
30. Electric Utility Consultants, Denver, CO, April 1998
31. University of Indiana, Indianapolis, IN, August 1998
32. Edison Electric Institute, Newport, RI, September 1998
33. University of Southern California, Los Angeles, CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio, TX, April 2000
38. Infocast, Chicago, IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000

40. IOU-EDA, Brewster, MA, July 2000
41. Infocast, Washington, DC, October 2000
42. Wisconsin Public Utility Institute, Madison, WI, November 2000
43. Infocast, Boston, MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa, FL, August 2001
45. Infocast, Washington, DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto, ON, March 2002
47. Canadian Electricity Association, Whistler, BC, May 2002
48. Canadian Electricity Association, Montreal, PQ, September 2002
49. Ontario Energy Association, Toronto, ON, November 2002
50. Canadian Gas Association, Toronto, ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge, LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax, NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto, ON, June 2006
59. Edison Electric Institute, Madison, WI, August 2006
60. Law Seminars, Las Vegas, February 2007
61. Edison Electric Institute, Madison, WI, August 2007
62. Edison Electric Institute, national eforum, 2007
63. EUCI, Arlington VA, September 2007 [Conference chair]
64. EUCI, Arlington, VA September 2007
65. EUCI, Denver, 2008 [Conference chair]
66. EUCI, Toronto, March 2008 [Conference chair]
67. EUCI, Chicago, July 2008 [Conference chair]
68. Edison Electric Institute, Madison, WI, August 2008
69. EUCI, Cambridge, March 2009 [Conference chair]
70. Edison Electric Institute, national eforum, May 2009.
71. Edison Electric Institute, Madison WI, August 2009

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

The Regulatory Assistance Project

REVENUE DECOUPLING

STANDARDS AND CRITERIA

A Report to the Minnesota Public Utilities Commission

30 June 2008
Final

Wayne Shirley
Jim Lazar
Frederick Weston

50 State Street, Suite 3
Montpelier, Vermont USA 05602
Tel: 802.223.8199
Fax: 802.223.8172

27 Penny Lane
Cedar Crest, New Mexico USA 87008
Tel: 505.286.4486
Fax: 773.347.1512

110 B Water St.
Hallowell, Maine USA 04347
Tel: 207.623.8393
Fax: 207.623.8369

Website: http://www.raponline.org

Table of Contents

I. Introduction

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the PUC will have established. The full text of Section 216B.2412 can be found in Appendix A.

To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). RAP is a non-profit organization dedicated, as its name connotes, to providing policy and technical assistance to regulators and other government officials on the full range of matters relating to the economic and environmental sustainability of the regulated natural gas and electric sectors. It was formed in 1992.[1]

The groundwork for this report was laid through a series of meetings April and May 2008 with commissioners and staff of the PUC, officials at the Office of the Attorney General, and staff at the Office of Energy Security, through written comments from stakeholders, and through a two-day workshop attended by representatives of the state agencies, affected utilities, and other interested parties. This report is the output of that collaboration.

A. What is Decoupling?

Section 216B.2412 states succinctly that decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Specifically, decoupling takes aim at one of the critical barriers to increased investment in cost-effective energy efficiency and other clean energy resources located "behind the customer's meter"—namely, the potentially deleterious impacts that such investment can have on utility

[1] RAP's principals are all former, highly experienced utility regulators. They have written and spoken extensively on numerous issues relating to energy policy and regulation, including efficiency, renewables, distributed resources, portfolio management, industry restructuring (e.g. market power, stranded costs, system benefits charges, customer choice, and consumer protection), reliability and risk management, rate design, electrical energy security, and environmental protection. Decoupling has been a particular focus of RAP's work over the years. RAP principals were involved in the development of decoupling programs in New England and the Northwest in the 1990s and, more recently, have provided technical assistance on it to a number of states (among them Maine, Massachusetts, Maryland, New Hampshire, the District of Columbia, and Oklahoma). This work has been underpinned by more in-depth analytical work on the mechanics of decoupling and utility incentives to encourage increased investment in energy efficiency. See, for instance, *Profits and Progress through Distributed Resources* (2000), *Performance-Based Regulation for Distribution Utilities* (2000), the Revenue Stability Model Rate Rider (2006), and "Utility Business Models: Clean Energy Incentives and Disincentives" (2008), all available at our website, www.raponline.org.

finances under traditional cost-of-service regulation. Traditional regulation, which is an exercise in price-setting, creates an environment in which revenue levels are a function of sales—kilowatts, kilowatt-hours, or therms. Consequently, a utility's profitability depends on maintaining or, more often, increasing sales, even though such sales may be, from a broader societal perspective, economically inefficient or environmentally harmful.

All regulation is, in one way or another, incentive regulation. A question all policymakers should ask is: how does a regulated company make money? What are the incentives it faces and do they cause it to act in a manner that is most consistent with, and most able to advance, the state's public policy objectives? And, if not, how should regulatory methods be reformed to correct such deficiencies?

Traditional regulation does not set a utility's revenues, only its prices. Once prices are set, the utility's financial performance depends on two factors: its levels of electricity sales and its ability to manage its costs. Because, under most circumstances, a utility's marginal revenue (i.e., price) significantly exceeds its short-run marginal costs, the impacts on profits from changes in sales can be profound. Moreover, the change in profits is disproportionately greater than the change in revenues. A utility therefore typically has a very strong incentive to increase sales and, conversely, an equally strong incentive to protect against decreases in sales.[2] This is referred to as the "throughput incentive," and it inhibits a company from supporting investment in and use of least-cost energy resources, when they are most efficient, and it encourages the company to promote incremental sales, even when they are wasteful.

The solution to the throughput problem is to adopt a means of collecting a utility's revenue needs that is not related to its actual volumes of sales. Decoupling, whereby the mathematical link between sales volumes and revenues is broken, eliminates the throughput incentive and focuses a utility's attention on its customers' energy service requirements and the economic efficiency of its own operations.[3] It renders revenue levels immune to changes in sales. Of equal importance, decoupling allows for the retention of volumetric, unit-based pricing structures that reflect the long-term economic costs of serving demand and preserves the linkage between consumers' energy costs and their levels of consumption.

Decoupling, in its current manifestations, is being applied only to the network, delivery components of the gas and electric industries. The costs of the gas and electric commodity portions of service are typically recovered through purchased gas and fuel adjustment clauses or, if provided competitively, through payments to suppliers. In effect, where such adjustment clauses are used, the commodity costs are already decoupled and changes in these costs due to changes in sales or in the underlying price of the commodity do not have an effect on the utility's profits. In this report, only the monopoly pipes and wires components of the networks need be addressed through a decoupling mechanism.

---

[2] See Appendix B for the mathematical bases for these conclusions.

[3] This point deserves emphasis. Decoupling breaks the link between unit sales and revenues, not *profits*. Decoupling does not assure the utility a fixed level of earnings but rather a pre-determined level of revenues: the actual level of profits will still depend on the company's ability to manage its costs.

A number of states have taken, or are now taking, steps to reform their methods of regulation to resolve the conflict between the "throughput" incentive and important public policy objectives. Decoupling, in one form or another, has been adopted for electric and gas utilities in California, Oregon, Washington, Maryland, Idaho, New York, New Jersey, Utah, Indiana, Ohio, North Carolina, and Vermont, and it is currently under review in Connecticut, Maine, Massachusetts, and the District of Columbia. See Appendix D for descriptions of decoupling regimes in the various jurisdictions.

B. Terminology

In this report, we describe the several approaches to decoupling taken by a number of states, and we use a specialized vocabulary to differentiate among them. These terms of art should, for clarity's sake, be defined, and the differences among them explained, at the start.

1. Full Decoupling

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation—e.g., increased investment in energy efficiency, unexpected weather, changes in economic activity—does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement—i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service—is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[4]

The most common form of full decoupling is revenue-per-Customer (RPC) decoupling, in which the allowed revenue requirement between rate cases is changed only as the number of customers served changes.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in

---

[4] This is the simplest form of full decoupling. As described later in this report, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate case horizon), costs vary more closely with other causes, primarily changes in the numbers of customers.

energy efficiency or other customer-sited resources, but its natural antagonism to such resources is removed.

2. Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 90% of the revenue shortfall is recovered).

3. Limited Decoupling

Under limited decoupling, only specified causes of variations in sales result in adjustments. For example:

(A) Only variations due to weather are subject to the true-up (i.e., actual year revenues (sales) are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and revenues from which the utility would not be insulated—that is, all else being equal, energy efficiency would adversely affect the company's bottom line.

(B) Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,

(C) Some combination of the two.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability are sometimes vigorously debated. But, more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation? These and other questions are taken up in the following chapter.

C. Structure of the Report

Chapter II analyzes the key issues—among them, impacts on customers, effects on utility investment, how risks are borne by the utility and the consumer, impacts on capital costs—that decoupling elicits. In that chapter, we address concerns and questions raised in meetings and correspondence with government officials and other interested parties. Chapter III lays out our recommendations for both the elements that a decoupling proposal should include (i.e., minimum standards) and the criteria by which it should be evaluated. Chapter IV gives an example of a decoupling program that meets those standards and criteria. The Appendices provide more detailed information about Minnesota's decoupling legislation, the mechanics of decoupling, and approaches to it in other states.

II. Issues

A. Investment in End-Use Efficiency and Other Customer-Sited Resources

Decoupling, which allows a utility to collect revenues according to a mathematical rule (i.e., revenue per customer, historic or future test year revenue requirement, etc.) that is not driven by unit sales, gives the firm a strong incentive to improve its operational efficiency. Indeed, it is only through such productivity increases that the company will be able to earn increased profits, as any margins associated with incremental sales will be returned to consumers (as, conversely, will any lost margins resulting from decreased sales be absorbed by consumers). In this light, an argument can be made that decoupling is appropriate on broad economic efficiency grounds, since it removes the company's inhibition from supporting investment in and use of least-cost energy resources, when they are most efficient, and likewise relieves it of its incentive to promote incremental sales, even when they are wasteful.

The removal of the throughput problem is critical if utilities are not to view investment in energy efficiency as a financial threat, but by itself it does not give them a positive incentive to support investment in behind-the-meter resources. It merely makes them financially indifferent to resource choices. Consequently, if increased investment in energy efficiency is a goal of state policy, a decision to decouple should be accompanied by specified efficiency performance requirements and possibly positive incentives for good or superior performance. It is important to see decoupling as one in a suite of complementary policies that can put the gas and electric sectors on a more economically sustainable long-term path.

B. Impacts on Customers

Several participants in the workshops and meetings expressed concerns about the potential impacts of decoupling on consumers. What are its costs and benefits, and can they be easily quantified so as to inform the decision-making and design process? Does regulatory lag—the interval between rate cases—benefit or harm ratepayers, and how does decoupling affect it? Should a change in regulatory methods be adopted only if it can be shown to do no harm to consumers, and how should "no harm" be defined?

The benefits and costs of decoupling, relative to traditional regulation, might be categorized as follows: (1) those associated with regulation and administration, (2) those having to do with short-term impacts on the revenue requirement, and (3) those having to do with the long-term societal costs of meeting demand for service.

In the first instance, a decoupling regime, once in place, should impose little incremental regulatory costs for either the utility or the regulatory agencies themselves. The overwhelming cost in ratemaking is the rate case itself, and decoupling will not change the nature of "soup to nuts" rate cases. To the degree that a decoupling program alters the timing of rate cases, their aggregate cost over a multi-year period will either increase or decrease when compared to what was expected to happen under traditional regulation. It is reasonable to expect that, with risk and revenue volatility reduced, a well-designed decoupling program (one that possibly allows for adjustments according to changes in short-term drivers such as numbers of customers, inflation, and productivity) could reduce the frequency of general rate cases. The costs of administrating the decoupling program itself—for example, the periodic adjustments to rates—should be negligible, akin to those associated with other on-the-bill rate adjustment mechanisms such as purchased gas adjustment clauses.

In the second case, the question really comes down to regulatory lag. Under traditional regulation, once prices are set, the company's profitability is a function of two things: its sales and its ability to manage its costs. If its earnings are (at least) satisfactory, it will not seek an increase in rates. To the extent that its earnings exceed its allowed returns, and the regulatory commission does not initiate a rate reduction proceeding, shareholders benefit from regulatory lag. The longer a rate case is avoided, the better off they are, and consumers will pay more for service than is necessary. Conversely, when earnings begin or threaten to decline, the company will seek rate relief. Regulatory lag in this case harms shareholders.[5] Rates are lower than they would otherwise be, and this is deemed to be a benefit to ratepayers. Therefore (and setting aside for the moment issues of how capital markets assess the risks, including regulatory lag, that utilities bear under traditional regulation), whether regulatory lag is of value to consumers or shareholders depends entirely on the underlying circumstances.

Decoupling reduces or even eliminates regulatory lag with respect to changes in sales volumes. If we conclude that, over the long term, the gains and losses of regulatory lag under traditional regulation are evenly distributed, then we might also find that, on this point at least, decoupling offers no incremental benefit to, nor imposes no incremental cost on, consumers or shareholders. In the long run, consumers will pay for the system that their demand creates and shareholders will be compensated for their investments. Under traditional regulation, there will be some periods in which they will pay a little more than they should, and in other periods a little less. Under decoupling, there will be neither over-collections nor under-collections of allowed revenues.[6] Even so, if there are underlying trends in consumption, regulatory lag under traditional regulation will reflect those trends in the utility's revenues and, therefore, its profits – utilities with increasing sales per customer (typical of electric utilities) will tend to see higher profits with longer regulatory lag, while those with decreasing sales (typical of gas utilities) will tend to see greater profit erosion. These trends can have impacts on the utility's perceived risk profile and, therefore, its cost of capital.[7]

---

[5] One example of this is the company whose sales volumes (per customer or in the aggregate) are falling. As a general matter, this describes Minnesota's natural gas utilities.

[6] Strictly speaking, this will depend on the frequency of the decoupling adjustments. Small gains and losses can flow from, say, quarterly or yearly adjustments. Monthly (i.e. "current") adjustments based on actual sales levels will eliminate regulatory lag altogether.

[7] See the subsection following for a fuller discussion of the impacts of decoupling on risk.

The third category of benefits and costs are those that flow from the longer-term changes in behavior that decoupling causes. One is management's greater focus on operational efficiency that a revenue cap creates, particularly one that has explicit adjustments for productivity gains over time. Another is the overall savings that consumers enjoy from an increased emphasis on long-term, least-cost strategies for meeting demand. As mentioned earlier, this emphasis will derive from the express public policy directives that accompany—and are made more realizable—by decoupling. Chief among those actions should be, as the legislation calls for, increased investment in end-use energy efficiency, but there are others too that utilities and regulators may be more apt to test and utilize, if the problem of revenue erosion has been resolved. One such action could be the reduction of fixed, recurring customer charges and the corresponding increase in unit charges to more accurately reflect the long-run economic and environmental costs of energy production and delivery.

Lastly, Section 216B.2412, Subd. 2, requires that "The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 *without adversely affecting utility ratepayers*." (Emphasis added.) There was some debate in the workshops and meetings about precisely what this means. This is, ultimately, a question of law that the Commission must decide. We suggest here that there are at least several kinds of impacts, both adverse and otherwise, that ought to be considered when evaluating the differences between decoupling and traditional regulation: the intertemporal distribution of costs and benefits, effects on bills v. effects on rates, the direct and indirect effects on market prices, risk and its effect on the cost of capital, and environmental impacts, to name a few. In certain cases they can be readily quantified and the trade-offs examined, in others not. But, either way, Minnesota law requires that they be factored into an assessment of whether this form of regulation, or any other, is most likely to promote the general good of the state.

C. Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors which prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or Limited Decoupling, and some forms of Partial Decoupling, will have a direct impact on the magnitude of these risks. For the most part, Full Decoupling will eliminate these risks completely. Limited Decoupling partially eliminates these risks. Partial Decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

1. Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a "fair" rate of return-- the utility's profits). Because most of the revenues are normally collected through volumetric prices based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[8] The basic pricing formula under traditional regulation is:

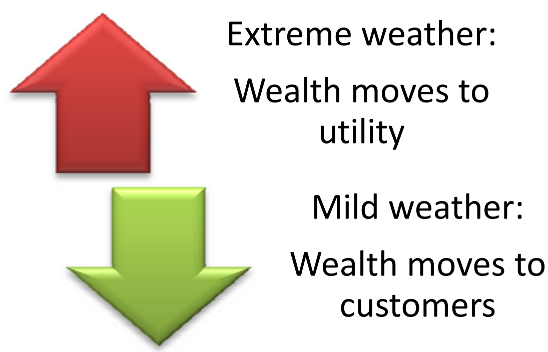
Price = Revenue Requirement ÷ Units of Consumption

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumptions remain unchanged, the prices set in a rate case will generate revenues equal to the utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery and customers from over-payment of the utility's cost of service because there should be an equal chance of having weather which is more extreme or milder than normal.

In reality, this is hard to accomplish because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices which are "right" and the weather normalization method used was accurate, the *actual* revenues collected by the utility and paid by the customers will be a function of the *actual* units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

Actual Revenues = Price * Actual Units of Consumption

Effect of Weather under Traditional Regulation On Utility Revenues and Customer Bills



With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills. To the extent that the utility's costs to provide service due to the increase or decrease in sales do not change enough to fully offset the revenue change, then, in economic terms, this is considered to be a wealth transfer between the utility and its customers. This wealth transfer is unrelated to what the utility *needs* to recover and what customers *ought* to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

[8] By "right," we mean consistent with the cost of service methodology.

2. Economic Risk

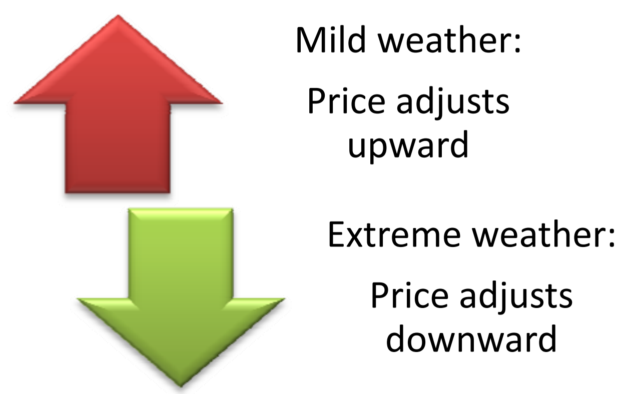
Other changes in circumstances, such as a significant change in economic conditions, can also affect a utility's revenues. Any upswing or downswing in either overall consumption levels or in the number of customers can potentially have a significant impact on revenues. Unlike weather risk, economic risk does not directly result in a wealth transfer between the utility and its customers, at least in so far as the increased or decreased consumption is associated with increased or decreased value received. Instead, the utility largely bears the benefit or burden of changed economic conditions between rate cases, while existing customers see no change in their bills. At the time of the next rate case, however, the utility's revenues are reset to approximate their cost of service and customers then see the effect of changed economic conditions going forward. As in the case of weather risk, there is an implicit volatility risk premium in the utility's cost of capital that reflects the increased variability in earnings associated with changed economic conditions.

3. The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

Price = Allowed Revenue ÷ Actual Units of Consumption

Effect of Weather With Decoupling
On The Non-Commodity Portion of Utility Bill



As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With Full Decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the Allowed Revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under Limited Decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment is limited, both weather and economic risks are placed upon the utility and its customers.

Under partial decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved weather risk in a decoupled environment by weather normalizing Actual Unit Sales before computing the new price under partial decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed below under Alternatives to Decoupling, are one example of this type of partial decoupling. This has the effect of preserving all of the risks, including weather and economic risks, which would be present under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Volatility Risks and Impacts on the Cost of Capital*.

D. Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. As a result of this volatility, utilities typically retain a relatively high level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer or utility-financed conservation, self-curtailment due to price elasticity, etc.). This in turn, lowers the financial risk for the utility, which in turn is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires several years to play out and the consequent benefits for customers are therefore slow to materialize. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.

1. Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, while the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically-integrated utilities with some risk mitigation measures are in-between.[9]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. The table below summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Quantification of Savings from Capital Structure Shift
$1 Billion Rate Base

Element	***Allowed Return***	***Ratio w/o Decoupling***	***Ratio With Decoupling***
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement		$104.8 million	$101.3 million
Difference			($3.5 million)

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact – but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

---

[9] See Standard and Poor's, *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004.

A utility could adapt its actual capital structure to reflect this change, by either issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the reduction in risk afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first. They are discussed in Subsection 3, below.

2. Some Impacts May Not Be Immediate, Others Are

If the rating agencies perceive a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does *not* change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, that earnings are more stable, and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional rate making process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years – or as much as a decade -- and the cost savings will phase in very slowly as new bonds are issued.

3. Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the rate-making process, with the risk that utilities then become resistant to implementation of decoupling. In other jurisdictions, utilities have pointed to past rate cases where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors, and that value will (eventually) be revealed in some way in the market – through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the economic theory, however, utilities may tend to view a reduction in the return on equity as a "penalty" associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides – that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.

4. Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline) the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

E. Rate Design Issues Associated With Decoupling

Decoupling should remove traditional utility objections to electric and natural gas rate designs which encourage energy conservation, voluntary curtailment, and peak load management. Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. A reduction of throughput will likely reduce revenues faster than the savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

The best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric, typical of those of all gas utilities and at least the investor-owned electric utilities in California, are shown below. Both the gas and electric rates are set up with a "baseline" allocation which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service; if usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

PG&E Natural Gas Rate at May 1, 2008

Rate Element	*Baseline Quantities*	*Excess Quantities*
Minimum Monthly Charge	~$3.00/month	
Base Rate per therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.17700	$0.17700
Low-Income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

PG&E Electric Rate
Rate E-1 at May 1, 2008

Rate Element	*Low-Income*	*All Other Customers*
Minimum Monthly Charge	~$3.50	~$4.45
Baseline Quantities	$.08316	$.11559
101% - 130% of Baseline	$.09563	$.13142
131% - 200% of Baseline	$.09563	$.22580
200% - 300% of Baseline	$.09563	$.31304
Over 300% of Baseline	$.09563	$.35876

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for Pacific Gas and Electric (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

Revenue stability needs of the company can conflict with principles of cost-causation as they relate to consumers. Utilities are interested in revenue stability so that they have net income which can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or energy conservation efforts of consumers. Cost of service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage and LNG facilities) and those capacity costs are allocated exclusively to excess use in winter and summer months, the cost to consumers of excess usage is dramatically higher than the cost of base usage. A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage that requires that capacity. While this is arguably "fair," doing so can result in serious revenue stability issues for the utility. Decoupling is one way to address the revenue stability issue for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

Customers also have an interest in bill stability, because in extremely cold winters, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause.

1. Addressing Revenue and Bill Volatility

There are three principal options typically proposed to address the problem of revenue and bill volatility. These include decoupling, Straight Fixed/Variable rate design, and budget billing programs. Budget billing is typically offered by utilities regardless of rate design, and we will consider it beyond the scope of this review. Straight Fixed/Variable rate design is discussed below, under Alternatives to Decoupling.

2. Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based regulation, and he identified ten principles, some of which are in tension with each other, to guide the design of utility prices. Three in particular—on the one hand, rates should yield the total revenue requirement and they should provide predictable and stable revenues and, on the other, they should be set so as to promote economically-efficient consumption—demonstrate that tension.[10] In certain instances, more economically efficient pricing structures could lead to customer behavior that in turn results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include the following

a) Zero or Minimal Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental costs.[11] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage they offered and confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

---

[10] Bonbright, James C., *Principles of Public Utility Rates* (Public Utilities Reports, Inc., Columbia University Press, New York, 1961), p. 291.

[11] For electric utilities depending on coal for the majority of their supply, valuing CO_2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 - $100/tonne) would add up to $.05/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

The California utilities, under decoupling, have retained zero or minimal customer charges.

b) Inverted Rate Blocks

Inverted block rates, of the type shown above for Pacific Gas and Electric Company, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. They serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

c) Seasonal Rates

Seasonal rates are typically imposed by utilities with significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

3. Summary: Rate Design Issues

The hypothetically "correct" rate design for an electric and gas utility can be a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count), and an inverted block rate design based on the load factors of typical end-uses. The California rates shown above for Pacific Gas and Electric contain these characteristics.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest cost of service.

Taking a hypothetical electric utility, with typical meter reading and billing costs, capacity costs of $15/kW per month and energy costs of $.05/kWh, produces the following cost-based rate design:

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$.03	$.05	$.08
Next 400 kWh Water Heat	40%	$.05	$.05	$.10
Over 800 kWh Space Conditioning	20%	$.10	$.05	$.15

Establishing theoretically correct rate designs such as those imposed by Pacific Gas and Electric provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely to respond to the incremental prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section IV of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

F. Alternatives to Decoupling

The principal goal of decoupling is to remove the disincentive to investment in energy efficiency that exists when utility net income is tied to sales volumes. There are a number of other tools that regulators have employed to address this concern. Each has potential advantages over decoupling, but each also has limitations on how well it addresses the principal regulatory goals of decoupling.

1. Lost Margin Recovery Mechanisms

A lost margin recovery mechanism compensates the utility for the sales margin lost when consumers take advantage of utility energy conservation programs. The advantage of these mechanisms is that they only compensate the utility for margin lost as a result of utility programs, and consumer advocates sometimes favor this limited cost recovery.

Experience with lost margin recovery in Hawaii from 1992 to 2005 demonstrated several shortcomings.

First, lost margin recovery does not affect the throughput incentive: if the utility's short-run marginal cost is lower than its retail rate, it still profits when sales increase. The incentive, therefore, is to fund programs which produce theoretical savings (generating lost margin recovery) but not actual savings.

Second, the utility may have a powerful incentive to discourage energy efficiency that does not involve utility programs. For example, the utility might receive lost margin recovery when builders accept utility incentive payments to build more efficient homes, but would resist improved energy codes, since these would also produce lower margins per customer, but would not fall into the "utility program" limitation of the lost margin mechanism. The result would be to encourage high-cost conservation while discouraging low-cost energy code improvements.

Finally, lost margin mechanisms are very tedious, requiring an estimate of the energy savings from each utility conservation program, and, in some cases, a separate calculation of how many customers would have utilized similar conservation measures in the absence of a utility program (isolation of free riders). While conservation evaluation has become an advanced science, this is a very time-consuming element of lost margin mechanisms.

2. Frequent Rate Cases, Multi-Year Rate Cases

If rate cases are held frequently, utilities do not suffer lost margins from energy efficiency programs for very long. In future test year jurisdictions, such as Minnesota, annual rate cases would, in theory, completely eliminate any lost margins. However, the incentive between rate cases would remain the same – if short-run marginal costs are lower than retail rates, the incentive is to increase throughput.

3. Straight Fixed-Variable Rate Design

Natural gas utilities frequently advocate Straight Fixed-Variable (SFV) rate design as a tool to stabilize income, and also argue that this would eliminate the throughput incentive, removing the barrier to utility-funded conservation efforts.

SFV rate design imposes a fixed charge to customers which is designed to recover all "fixed" costs. The definition of fixed costs in this context typically goes far beyond the accounting definition of fixed costs (interest and depreciation) to include the return on equity, plus the bulk of distribution operation and maintenance expenses, and federal and state income taxes.

An SFV rate design might have the following rate form:

Rate Element	Price per Unit
Customer Charge / month	$30.00
Distribution Charge / therm	$0.00
Gas Supply Charge / therm	$1.00

This type of rate design is almost unheard of in competitive industries, because it would chase away profitable customers. Hotels have high fixed costs, but recover their costs per room-night. Airlines have high fixed costs, and recover their costs from each ticket sold. Oil refineries have immense fixed costs (as do oil pipelines, oil product pipelines, and gasoline retailers), but all of these costs are recovered per-gallon. Even in the telecommunications industry, as dominant carriers have succeeded in implementing rates with high fixed charges, wireline access lines have actually begun to decline, reversing a 100-year upward trend. This type of pricing has spurred the development of an entire group of prepaid wireless competitors offering basic telephone service for $5 - $10/month with limited calling.

There are several problems with SFV rate design. First and foremost, it adversely affects small users. These are not universally low-income consumers; but, for the majority of low-income users, who do use less than the average amount of energy, SFV could have a disproportionately large negative impact. Second, it adversely affects residents of multi-unit and multi-family housing, who typically have lower-than-average costs of distribution service due to their proximity to other customers, but also have lower-than-average usage per unit. Many of the residents of multi-family housing are low-income or fixed-income seniors.

Perhaps most important, SFV pricing shifts costs of seldom-used peaking capacity (distribution main capacity and LNG peaking facilities) from heating consumption during extreme weather to usage of non-heating customers, and non-heating usage of all customers. It results in a mismatch of cost causation and cost recovery.

a) Elasticity Impacts of Straight Fixed-Variable Pricing

Perhaps the most serious adverse societal impact of SFV is the increased energy consumption that is expected to result from reducing the variable component of pricing. In a simplified example, shown in Appendix F, a shift from pure volumetric pricing to pure SFV pricing could result in an 18% increase in the quantity of natural gas required to meet customer needs, even with continued volumetric pricing of gas commodity. This elasticity effect could more than negate the savings from all utility energy efficiency programs.

b) Cost of Capital Impacts of Straight Fixed-Variable Pricing

SFV pricing, like decoupling, eliminates utility earnings variability due to sales volume changes. Like decoupling, SFV pricing leaves earnings variation due to inflation, cost controls, changes in interest rates, and other causes unaffected. The cost of capital effect of SFV pricing should be expected to be similar to that for decoupling.

4. Weather-Only Normalization

Many natural gas utilities have weather-only normalization mechanisms that adjust rates up in mild weather, and down in severe weather. These serve much of the function of decoupling in stabilizing both utility income and customer bills (if done in real-time). They do not reduce the throughput incentive, however, since weather-only normalization mechanisms only adjust for changes in weather, not for changes in sales volumes due to other causes. The weather adjustment factors are set in the rate case, based on test-year values. Any reduction in sales due to conservation would be uncompensated.

5. Real-Time Pricing

Academic economists frequently advocate real-time pricing (changing retail prices instantly to reflect changes in wholesale market conditions) as the cure for all ills that regulation allows. Real-time pricing is typically based on short-run marginal costs, when consumer investment in energy efficiency should be encouraged based on long-run costs (including the cost of externalities). In addition, extensive experience has demonstrated that there are significant barriers other than price to consumer-initiated investment in energy efficiency. Real-time pricing cannot be expected to produce the same level or type of energy efficiency investment and response that utility programs can produce.

6. Moving Efficiency Outside the Utility

Vermont, New York, Oregon, Wisconsin, and Hawaii have approved the establishment of energy conservation organizations, funded through utility charges, but organizationally distinct from the utilities. The energy conservation organizations receive funding, make expenditures, and are accountable to regulators, but are not also electric or natural gas utilities, and therefore have no concern about lost distribution margins. Their incentive (to retain their status) is to deliver reliable and economic efficiency savings.

This option avoids the utility's disincentive for investment in energy efficiency by removing the utility's role in energy efficiency, except as a revenue collection mechanism, but does not cure the throughput issue and the associated impacts on the utility's revenues. It can also eliminate the risk of disallowances of energy efficiency investments, a minor risk given the level of oversight of most utility programs.

One disadvantage of moving energy efficiency programs outside the utility is that coordination with utility distribution planning is inevitably weakened. Utility-operated efficiency programs can focus on localized areas where significant distribution reinforcement is pending, avoiding not only production and transmission costs, but also distribution costs and losses. While it is theoretically possible for regulators to adopt policies to assure a high level of coordination, it may not be as effective as when the utility is operating the programs itself.

7. Elimination of PGAs and FACs

One of the earliest publications of the Regulatory Assistance Project founders detailed how fully-reconciled fuel and purchased power adjustment clauses for electric companies (FACs) and purchased gas adjustment clauses for gas utilities (PGAs) can have the effect of making every incremental sale profitable, and every sale lost to conservation unprofitable.[12] This is achieved by flowing through to all customers the incremental cost of additional resources, even when the retail price is lower than the incremental cost. For example, when utilities use fuel oil or diesel peaking generation sources, the high incremental costs of these sources are generally not directly translated into peak rates for customers. Instead, the FAC allows the cost of this high-priced power to be averaged into all sales, and the costs recovered. Thus, the utility can "make money" by producing power at an incremental fuel cost of $0.12/kWh, even though it sells that power for $0.08/kWh.

One alternative to decoupling would be to eliminate the PGA or the Fuel Adjustment Clause. This would eliminate this "guaranteed profitability of additional sales." This is unlikely to produce major benefits for energy efficiency, simply because there are

[12] See: Moskovitz, *Profits and Progress through Least- Cost Planning*, NARUC, 1989, p. 4: "In its understandable quest to maximize profits, a utility's most powerful incentive for selling more electricity is hidden in its regulatory fuel adjustment clause."

relatively few hours in which the short-run marginal cost is higher than the retail rate, and most conservation measures save energy over a broad spectrum of the utility load duration curve.

Elimination of the PGA or FAC for Minnesota utilities would, however, increase their exposure to cost volatility over which they have limited control. It would also increase the perceived financial risk of the utilities. In essence, this could have the opposite effect on the cost of capital to that of decoupling.

G. Performance Incentives

Incentives for superior performance can be used under traditional regulation as well as under decoupling. They may not, however, elicit the same responses in both cases. Commissions have attempted several types of incentives for energy efficiency in the past, and the results have been mixed.

1. Rate-of-Return Incentives

A rate of return incentive is a bonus to the allowed rate of return for energy efficiency programs. It can be tied to the level of investment (higher allowed return on equity for energy efficiency investments) or tied to the level of performance (a bonus based on achieving specific targets).

Experience with rate of return incentives has been mixed. In Washington, a 2% bonus rate of return incentive was in place from 1980 to 1990. By 1990 it was evident that the incentive was for the utility to spend as much as possible on programs that saved as little energy as necessary. One utility was found to be spending 50% of its residential energy efficiency budget subsidizing heat pumps, primarily in mobile home parks where natural gas service was not (yet) available. The clear goal of the electric utility was to retain the heating load, and to derive a bonus on its return on equity for doing so.

A rate of return incentive can work with a decoupling mechanism. The decoupling mechanism would eliminate the throughput incentive, while the rate of return incentive would provide a positive reward for conservation performance. However, tying the reward to the amount invested has the potential to lead to suboptimal investment plans.

2. Shared Savings Mechanisms

A number of states, including Minnesota, have established shared savings plans for energy efficiency. In theory, these can be large enough to overcome the throughput incentive – the “Save-a-Watt” program proposed in 2007 by Duke Power in North Carolina would provide the utility with 90% of the “avoided cost” for all sales avoided by utility conservation programs. Given that the avoided cost is the cost of a new nuclear, coal, natural gas, or renewable energy generator, and the cost of most energy conservation measures is 20% to 50% of this avoided cost, the Duke approach could be highly lucrative to shareholders, and likely overpower the throughput incentive. The Save-a-Watt approach increases the effective cost of energy efficiency from about $0.02-$0.03/kWh to as much as $0.08-$0.10/kWh (or more).

A modest shared savings mechanism, combined with a decoupling mechanism, would be likely to produce at least equal performance, at a dramatically lower cost to consumers. For example, a decoupling mechanism could make the utility “whole” when customers use less power or gas (for any reason), while a shared savings mechanism that gives the utility 10% of the savings from energy efficiency programs would provide an incentive for the utility to fund all cost-effective programs.

III.Recommendations: Criteria and Standards by Which to Design and Evaluate a Decoupling Proposal

Section 216B.2412 states that the Commission "shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors."

We see two broad categories of criteria and standards, and have organized our discussion along their lines. The first are the minimum design and informational requirements that a decoupling proposal should satisfy in order to be considered for approval by the Commission. The second are those that the proposal would have to meet before the Commission would approve it.

A. Elements to be Included in a Proposal

In the following subsections, we list the elements that a decoupling proposal should at a minimum include. They consist of both informational (i.e., filing) requirements and substantive design features.

1. Objectives

The proposal should begin with a set of clearly defined goals for the decoupling regime. What are the reasons for it, and why is it likely that the proposal will achieve these ends more efficiently than other forms of regulation? Among such objectives are:

- Risk reduction – and corresponding cost reductions – for consumers and shareholders;
- Increased investment in least-cost resources, in particular energy efficiency, thereby reducing the long-term costs of serving load;
- Increased efficiency in utility operations and management; and
- Objective analysis of other cost-effective energy-saving opportunities, including fuel-substitution, for consumers.

2. Description of the Decoupling Method

The mechanics of the decoupling proposal must be explained in detail. Elements to be described will include at least the following:

- *The mathematics of the mechanism*. How are revenues decoupled from sales, e.g., by revenue per customer, as a pre-determined annual revenue requirement (i.e., future test year), or in some other fashion? Is it full, partial, or limited decoupling?
- *Decoupling adjustments*. How will actual revenues be reconciled with allowed revenues? How often will the decoupling adjustments be made? Monthly (i.e. on

a billing cycle basis), quarterly, semi-annually, annually? Will they be applied on a customer-class basis or equally across all customer classes?

- *Timing:* Will the decoupling adjustments be implemented in the month in which sales volumes deviate from test year volumes, or will differences accrue and be deferred for later collection/rebate?
- *Term*. When will the decoupling program end? Are there provisions for renewal, including a full investigation of the underlying cost of service? Under what conditions, if any, can the decoupling program be prematurely terminated, and what actions (including a general rate case) can, or should, then be taken? Are the answers to these questions different if the initial decoupling proposal is for a "pilot program"?
- *Implementation*. When and how will the decoupling mechanism be implemented. For example, should implementation occur only in a rate case, or within a limited period of time after a rate case?

3. Revenue Requirement

If the proposal is submitted separately from a general rate case, does the proposed revenue requirement reflect a downward cost-of-capital adjustment?
If the proposal calls for a multi-year decoupling proposal, the means by which the allowed revenue will be adjusted in each of the later years, if at all (as distinguished from the decoupling adjustments themselves, e.g., numbers of customers), should be detailed. Such adjustments could be made through regular proceedings ("attrition cases," as in California) or through a mathematical overlay that might account for productivity gains, inflation, and a limited set of factors (sometimes referred to as "exogenous") whose cost impacts are not immediately captured in the other measures.[13]

4. Cost of Service

The decoupling proposal should be accompanied by a detailed class cost of service analysis.

To the extent that the decoupling mechanism is limited to certain classes of customers, the cost of service analysis should show how cost-of-capital benefits are flowed through to the participating classes.

---

[13] An example of a formula for adjusting a revenue requirement or an allowed revenue-per-customer figure is the following:

$$RPC_{t+1} = [RPC_t * (1 + i - p)] \pm Z$$

Where,

RPC_t = revenue requirement in year t
i = inflation rate
p = productivity rate
Z = exogenous costs, if any

The inflation rate would be a national measure of general changes in price levels in the economy, appropriate for the sector in question, e.g., the CPI-U. The productivity adjustment would be based on the industry average for similar firms. Exogenous costs might be the significant changes in the tax code (before they are captured by the inflation measure) or out-of-the-ordinary expenses for storm damages.

5. Energy Efficiency, Rate Design, and Other Public Policy Objectives

Because, under the Minnesota legislation, decoupling is seen as a means of overcoming utility disincentives to promote energy efficiency, it is imperative that a proposal explain how decoupling will advance the state's efficiency goals. Specifically, the proposal should include design details, including performance targets, incentives, and penalties, for programmatic efficiency efforts.[14]

Also to be considered are changes in retail rate designs that better relate the long-run costs of service to demand, thus better informing customers of the economic impacts of their consumption decisions. These could include, for natural gas service, reduced customer charges, adjustments to hook-up fees, and increased unit-based delivery and commodity charges. For electric service, more dynamic (time-sensitive) pricing structures, such as critical peak and even real-time pricing, and innovative tariffs for users with on-site generation, could be implemented. Oftentimes, the adoption of a new rate structure causes short-term revenue problems – over- or under-collections in particular rate classes. Decoupling relieves some of the pressure to assure revenue-neutrality for the class in question, when the new pricing goes into effect.

6. Service Quality Standards

A decoupling proposal should include a detailed set of service quality standards, and a schedule of penalties for failing to meet them. The standards to be measured should include, among others, numbers of outages, durations of outages, customer service response times, missed appointments for service or installations, the intervals between requests for new service and the provision of service, and numbers of disconnections.

Under traditional regulation, utility revenues fall when there are outages. Customers do not pay for services that they do not receive. Moreover, the utility has no recourse to collect such revenues foregone.[15] To the degree that outages and other customer inconveniences are due to the utility's own failures, regulators can take remedial action, in the form of financial penalties and other directives. But, it can be argued that the prospect of lost revenues is, by itself, a sufficient inducement to assure reasonable levels of customer service.

Some participants wondered whether decoupling, in particular full decoupling, undermines the utility's incentives to provide customer service, since it assures specified levels of revenue recovery regardless of actual sales. The concern is that the revenues foregone from an outage would simply be recovered from all other customers through the decoupling adjustment, and the company's enthusiasm to swiftly make repairs, maintain

[14] Several participants in the workshops and meetings noted that Section 216B.2412 does not answer the question of whether efficiency savings should, under a decoupling regime, exceed those that are expected under traditional regulation and given the current, legislatively mandated savings and spending levels. This is a question that the PUC will need to address.

[15] Except, perhaps, insofar as the outage is the result of an extraordinary event—say, a violent storm—over which the company had no control and whose financial consequences threaten the company's ability to provide safe, adequate, and reliable service going forward.

its system to the highest standards, ensure reliability, and provide a sufficient level of power quality would wane. While there is a logic to this line of thinking, we doubt that decoupling, by itself, would lead to an erosion of customer service (and, indeed, we've seen no evidence of it in other jurisdictions). Public opinion, general regulatory oversight, and the utility's corporate culture are probably sufficient to prevent it. Even so, customer service standards make sense as a general matter, particularly in conjunction with a multi-year rate plan. Consideration of a decoupling proposal provides an opportunity to develop and implement such standards, if they are lacking.

7. Existing Revenue Adjustments

A proposal should explain how current adjustments to collected revenues will be treated under the decoupling regime.

Today there are a number of adjustments that are made to the rates charged by Minnesota gas and electric utilities to assure the allowed amounts of money are collected to cover specified expenses. The natural gas commodity is one such expense, fuel and purchased power for electric generation are another. Costs associated with utilities Conservation Investment Programs are also collected in this fashion. The general intent of these adjustments is, in effect, to decouple the revenues associated with the expense from sales levels, while leaving the utility's base revenue requirements at risk. Indeed, this is a kind of partial decoupling.

It is likely that most, if not all, non-commodity adjustments can be eliminated under a decoupling program. This, of course, will depend upon the specifics of each adjustment (i.e., the manner in which it is made, the purpose it serves, the degree to which the utility can efficiently manage the cost under a revenue cap and whether the public good is advanced by its doing so, etc.), upon the nature of the decoupling regime (full, limited, or partial), and upon any law that governs them.

8. Reporting and Evaluation

A decoupling proposal should be accompanied by a plan for evaluating its efficacy. A prerequisite to the plan will be a defined set of reporting requirements. What information should be made available that either is not currently being collected or is not managed in a fashion most useful to an assessment of ratemaking methods? Among the categories of data to be provided should be the following:

- *Revenue Comparisons.* How would revenues under traditional regulation have differed from those collected under the decoupling regime? What are the relatives effects of efficiency programs, actual weather (to the extent that there is not a weather adjustment under traditional regulation), and other factors on revenues.
- *Bill Comparisons.* A corollary to the question of revenues is that of customer bills. How have average bills differed from those under traditional regulation?
- *Energy Efficiency*. Is the company meeting its energy efficiency savings goals? Has energy efficiency achievement been enhanced under the decoupling mechanism?

- *Service Quality.* Is the company meeting its service quality targets? Has service quality declined?
- *Risk.* Has the decoupling regime stabilized revenues as expected and, if so, how has this affected the utility's overall risk profile?

9. Customer Information

The proposal should describe how customers will be informed of the decoupling program, how it works and what it means for them, and how the adjustments will be made on their bills.

B. Criteria by Which to Evaluate a Proposal

The criteria for evaluating a decoupling proposal, or any proposal to reform regulatory methods, should be should be framed with an eye to the alternatives (including traditional regulation). Is it more likely than the alternatives to achieve stated public policy goals? Thus, the evaluation is essentially comparative in nature. Regulators should test a proposal against the following criteria:

- *Objectives:* Are the objectives that have been set out for the decoupling program appropriate? Is the proposal likely to achieve them? Will it achieve the overarching goal of aligning the utility's financial incentives with the state's public policy objectives? Is it more likely to do so than the alternatives? Will the general good of the state be promoted by it?
- *Revenue Requirement:* Will this form of regulation result in a lower long-run cost of service, and therefore a lower revenue requirement, than the alternatives?
- *Just and reasonable rates:* Will the rates charged under the decoupling regime be just and reasonable?
- *Quality of service:* Will service reliability and quality deteriorate, remain the same, or improve under the decoupling program?
- *Efficiency:* Is the decoupling program accompanied by a meaningful increase in the utility's investment in energy efficiency resources, above and beyond that which is required by Minn. Stat. § 216B.2401[16] and Minn. Stat. § 216B.241, subd. 1c(b)[17]?
- *Other public policy goals:* Will decoupling inhibit or advance achievement of other public policy aims, such as infrastructure development and emissions

[16] 216B.2401 ENERGY CONSERVATION POLICY GOAL.
It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

[17] 216B.241 ENERGY CONSERVATION IMPROVEMENT
Subd. 1c. (b) Energy-saving goals. (b) Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

reductions? How will the decoupling plan affect the utility's ability to achieve these objectives?

- *Simplicity and ease of administration:* Will administration of decoupling be significantly more difficult than traditional regulation? How will it affect resource needs at the Commission and other state agencies? Will the program be easy to administer, both for the utility and the regulators?
- *Transparency:* Will the mechanics of the decoupling be easily discerned? Will the calculations of the adjustments be easy to understand and follow?
- *Comprehensibility:* Is the program easily understood? Can its features be easily communicated? Has the utility designed a satisfactory public information campaign to explain it to consumers?
- *Consequences:* What is the likelihood of unwanted outcomes (e.g., significant over- or under-earnings)? Is it greater than under the alternatives?
- *"Off-Ramps"*: Does the mechanism have a pre-determined set of conditions under which it would self-terminate or be subject to regulatory review if the impacts are significantly different from those anticipated at approval?

IV. Straw Proposal

This straw proposal is a concept that seeks to design a natural gas utility decoupling mechanism that incorporates the best features of the decoupling plans now in operation, and takes into account comments heard from participants in the Minnesota workshop.

Revenue per Customer Decoupling, With Separate Old/New Customers Revenue Per Customer Values: The utility distribution revenue requirement will be the sum of the allowed revenue requirement from the rate case, plus the product of customer growth since the test year and the average incremental distribution revenue of new customers. The old/new distinction is designed to recognize that new homes built to modern codes use less natural gas and would contribute lower revenues.[18]

Classes to be Included: At a minimum, the pilot program shall include the residential and small commercial class(es) of customers. Additional classes may be included in the pilot proposal. As an alternative, the Commission may consider extending the pilot to all firm service customers.

Current (not accrual) Decoupling: The decoupling adjustment shall be calculated for each billing cycle, based on actual throughput versus rate case normalized throughput adjusted for new customer volumes. Average monthly revenue per customer shall be determined from general rate case data, and pro-rated across billing periods that span adjacent months.

Rate Design: The utility shall file a rate design with a customer charge that does not exceed the cost of metering, meter reading, and billing expenses. All other costs shall be reflected in a volumetric distribution charge. The PGA mechanism shall continue to be computed monthly.

Cost of Capital: If filed independently of a general rate case, the filing shall incorporate a 1% reduction in the distribution revenue requirement to the classes included in the pilot, to reflect a portion of the lower financial risk resulting from decoupling. If filed in the context of a general rate case, the lower financial risk resulting from decoupling shall be reflected in the utility's proposal and can be addressed by the parties in the rate case. The benefits of the reduced financial risk shall be reflected in the revenue requirement (whether through a lower ROE, an imputed capital structure, or some other means) of the classes of customers included in the pilot program.

Rate Cap: During any 12 month period, the total rate surcharges shall not exceed 3% of the test year revenue requirement. Any decoupling adjustments in excess of this amount shall be deferred, and be recoverable only after a Commission investigation into whether the mechanism is operating properly, providing recovery of lost distribution margins, but not producing windfalls.

---

[18] If these new homes do not provide enough revenue to justify line extensions, the line extension policy is the appropriate tool to address this revenue shortfall, not the rate design or decoupling mechanism.

Duration: The filing shall contain a termination date not more than thirty-six months after the effective date. A general rate case filing is required to re-enact the decoupling mechanism.

Service Quality Index: A service quality index, with penalties up to 3% of gross revenues for performance that deteriorates from a baseline period, shall be included in the pilot. Elements to be included in the index shall include, at a minimum, the following elements:

- Time to answer a telephone call for customer service during business hours
- Time to respond to gas emergency calls
- Missed appointments for service or installations
- Time to reconnect service after conditions of restoration are met
- Number of customers disconnected for non-payment

Review Process: After twelve months of operation, the Commission shall conduct a limited review of performance, to determine if the mechanism is generally meeting expectations. If evidence indicates that there is a significant difference between expectations and results, the Commission may terminate or modify the pilot.

After 24 months of operation, the Commission shall conduct a more comprehensive review of the pilot program to determine if the program should be continued with or without modification after the pilot period ends. Parties and interested persons may make recommendations as to the scope of the review and the means by which it is carried out, but the Commission shall make the final decisions in these respects. The results of the evaluation shall inform future utility decoupling proposals.

V. Appendices

A. Minnesota Statutes, Section 216B.2412

216B.2412 DECOUPLING OF ENERGY SALES FROM REVENUES.

Subdivision 1. **Definition and purpose.** For the purpose of this section, "decoupling" means a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency.

Subd. 2. **Decoupling criteria.** The commission shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors.

Subd. 3. **Pilot programs.** The commission shall allow one or more rate-regulated utilities to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation. Each pilot program must utilize the criteria and standards established in subdivision 2 and be designed to determine whether a rate-decoupling strategy achieves energy savings. On or before a date established by the commission, the commission shall require electric and gas utilities that intend to implement a decoupling program to file a decoupling pilot plan, which shall be approved or approved as modified by the commission. A pilot program may not exceed three years in length. Any extension beyond three years can only be approved in a general rate case, unless that decoupling program was previously approved as part of a general rate case. The commission shall report on the programs annually to the chairs of the house of representatives and senate committees with primary jurisdiction over energy policy.

B. The Throughput Incentive, Costs, and the Rationale for Decoupling

All regulation rewards behavior of one kind or another. Any method of cost recovery through a regulatory process provides a set of incentives to which the regulated companies will respond. Understanding how utilities make money is essential to the design of public policy: a policy is more likely to be successful if it is not in tension with the financial interests of those directly affected by it.

Rate-of-return ratemaking as it has been practiced for more than a century is an exercise in price-setting. During that time, traditional regulation has effectively controlled monopoly power and facilitated the creation of the world's most advanced electric system, with service available virtually everywhere throughout the country, and the expansion of a reliable natural gas network from coast to coast. The steady improvements in technology and the decades of economies of scale to be captured meant that costs, in real terms, declined over much of the twentieth century, but also hid a significant drawback of price-based regulation, namely, that it lacks strong incentives to promote the overall efficiency of the electric and gas sectors.[19]

Under the traditional ratemaking, the revenues of a monopoly electric company are determined by its level of sales (revenues = price * sales). Given this, electric utilities increase their profits by doing two things: (1) improving the operational efficiency (i.e., reducing the costs) of supply and delivery and (2) increasing sales. While improving the efficiency of utility operations is a good thing, it is not the only thing. Policy should promote not only the efficiency of supply, but efficiency altogether – that is, the efficiency of both supply and demand. Because electricity and, in some cases, natural gas are intermediate goods in the economy – they are used to produce other goods and services that consumers demand – it is not the case that increasing production of electricity, though profitable for utility companies, is necessarily the most efficient (or least costly) means of meeting demand for the goods and services these commodities produce. As experience in Japan, Germany, California, and elsewhere has shown, reducing the energy intensity of an economy (Btu input per unit of GDP output) improves its efficiency and competitiveness, and makes it more resistant to the cataclysmic impacts of energy supply constraints.

Because under traditional regulation the revenues of a monopoly utility are a function of its sales, almost any reduction in sales will result in reduced profits for the company.[20] So, for example, DSM investment may be much less costly than additional supply, but, for the utility, adding supply means increased sales and increased revenue. Generally, the added revenue exceeds the added cost, so the grid utility's profits will increase when it chooses to increase supply. In contrast, the lower cost DSM option reduces sales and revenues. Even if the cost of DSM is zero, the lower revenue means that the DSM option reduces the grid utility's profit. This is a very powerful disincentive for grid utility investment in DSM.

The following tables illustrate this phenomenon. Table 1 summarizes the financial characteristics of a hypothetical, mid-sized electric or gas distribution company. Given test year sales levels and the company's known and measurable costs, it should earn $9.9 million. But sales and circumstances never match test-year assumptions, and changes in sales, for whatever reason, can have significant impacts on a company's bottom line.

---

[19] The most fundamental flaw of rate-of-return regulation, the incentive for utilities to gold-plate their systems, was recognized long ago. See, e.g., Averch, Harvey; Johnson, Leland L., *Behavior Of The Firm Under Regulatory Constraint* (American Economic Review, Dec 1962, Vol. 52 Issue 5), p. 1052*ff*.

[20] This is because, in most hours of the day, the marginal cost to produce and deliver a kilowatt-hour or therm is *less* than the marginal revenue received for that kilowatt-hour or therm. This inhibits a company from supporting investment in least-cost energy resources, when they are most efficient, and encourages the company to promote incremental sales, even when they are wasteful.

Table 1

Assumptions							
Operating Expenses	$160,000,000						
Rate Base	$200,000,000						
Tax Rate	35.00%						
			Wtd. Cost		Dollar Cost Amt.		
Cost of Capital	% of Total	Cost Rate	Pre-Tax	After-Tax	Pre-Tax	After-Tax	
Debt	55.00%	8.00%	4.40%	2.86%	$8,800,000	$5,720,000	
Equity	45.00%	11.00%	4.95%	7.62%	$9,900,000	$15,230,769	
Total	100.00%			10.48%			
Revenue Requirement							
Operating Expenses	$160,000,000						
Debt	$5,720,000						
Equity	$15,230,769						
Total	$180,950,769						
After-Tax Earnings	**$9,900,000**						

Table 2 shows the effects (all else being equal) of changes in sales, both up and down, on the company's earnings. In this example, a one-percent change in sales results in a roughly ten-percent change in earnings. Actual numbers will vary depending on a company's actual costs of service, but the essential finding – that impact on earnings will be disproportionately greater than the change in sales – will hold in all cases. This flows directly from the fact, noted earlier, that a utility's costs do not vary much at all with sales in the short run.

Table 2

	Revenue Change		Impact on Earns		
% Change in Sales	Pre-tax	After-tax	Net Earnings	%Change	Actual ROE
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	-23.76%	8.39%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-0.00%	$0	$0	$9,900,000	0.00%	11.00%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
4.00%	$7,238,031	$4,704,720	$14,604,720	47.52%	16.23%
5.00%	$9,047.538	$5,880,900	$15,780,900	59.40%	17.53%

The challenge for regulators, therefore, is to design a method of setting utility prices and revenues that rewards utilities for taking actions that also improve the economy and welfare of their customers. Put another way, what manner of regulation will make utility companies most profitable by achieving specified public policy objectives? How can regulators align the financial incentives of utilities with the interests of customers and the nation as a whole?

In 1989, recognizing that investment in end-use energy efficiency was at odds with the "throughput incentive" that price-based regulation gives utilities, the National Association of Regulatory Utility Commissioners adopted a resolution urging state commissions to "adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[21] In the years that followed, many states experimented with different approaches to deal with the problem – mostly, net lost revenue recovery, performance-based incentives and, more recently, decoupling, as state interest in substantial increases in efficiency investments has grown.

Revenue decoupling breaks the mathematical link between sales volumes and revenues (and, ultimately, profits). It makes revenue levels immune to changes in sales volumes. It enables the utility to recover its prudently incurred costs, including return on investment, in a way that doesn't create perverse incentives for unwanted actions and outcomes. It has two objectives: one, to protect the utility from the financial harm associated with least-cost actions and, two, to remove the utility's incentive to increase profits by increasing sales. And, because it is revenues, rather than earnings directly, that are decoupled, the utility's incentive to improve its operational and managerial efficiency is preserved. The utility benefits from managing its costs wisely.

Regulation is most successful when it links utility revenues to the costs and risks that a company faces. What is it that drives utility costs? In the long-run, of course, the primary driver is demand for energy service (therms and kilowatt-hours); without it, there would be no costs incurred.[22] But in the short-run (the rate-case horizon), utility costs vary more directly with numbers of customers than with sales or, where customer growth is relatively flat, with the need to replace aging, depreciated assets. This is particularly true of unbundled distribution service, where the short-run marginal costs of delivery are, on average, very low or nil, but for which the costs of acquiring and serving customers are significant and recurring. A revenue cap that is can be adjusted for these factors (e.g., a per-customer revenue cap or even a forecast of yearly revenue requirements), more closely links utility remuneration to the near-term costs and risks that the company faces.

It is through rate design that the long-term economically efficient signals are sent. Decoupling it is not intended to decouple customer bills from consumption. Unit-based pricing (per therm, per kW, per kWh) is essential for relating customer costs to usage: the more one uses the more one pays, and conversely. Customers continue to see the cost implications of their consumption decisions. A flat, non-volumetric monthly price per customer would be a form of decoupling – revenues would not be a function of sales – but it would come with other ills too great to justify it: inequity (low-volume users subsidize high-volume users) and an under-valuing of resources (it creates the notion that incremental usage is cost-free and thus would spur uneconomic demand). It is precisely to preserve usage-based pricing, while simultaneously resolving the throughput problem of traditional regulation, that decoupling was devised.

---

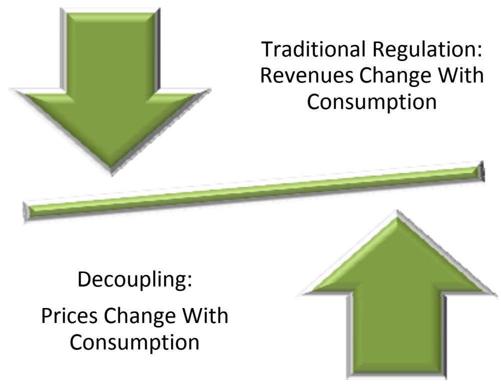
[21] National Association of Regulatory Utility Commissioners, "Resolution in Support of Incentives for Electric Utility Least-Cost Planning," adopted July 27, 1989.

[22] This is not to say that other factors, such as interest rates, commodity prices, and the state of the economy do not affect costs. They do. But we are merely stating the obvious – that it is the existence of the demand itself that causes the costs.

C. Essential Mechanics of Decoupling

Decoupling is accomplished through a simple change in regulation. Under traditional regulation, prices for the non-commodity portion of the utility's cost of service are set at the end of each rate case and remain in effect until the next rate case.[23] As a result, utility revenues and customer bills will rise or fall with changes in unit sales. With decoupling, revenues are held to a specified level and prices are allowed to change as necessary to collect that amount.

Traditional Regulation vs. Decoupling



1. Revenue-Cap Decoupling

The simplest form of decoupling, often called "revenue-cap decoupling" allows the utility to collect the exact revenue requirement determined in the last rate case. This is done by holding the annual Revenue Requirement constant between rate cases. In any period after the rate case, prices are recalculated by dividing the actual units of consumption into the Allowed Revenue, set in the last rate case. Table 3 demonstrates the mathematics of the calculation. The initial price comes from the last rate case and is derived by dividing the revenue requirement by the test year weather-normalized unit sales. In the example, the result is a price of $.10 per Unit of Sales. To this point, both traditional regulation and decoupling are identical in approach, but this is where they diverge. Whereas this price is *the* price under traditional regulation, it is actually of little importance under decoupling.

Table 3
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Post Rate Case Calculation	
Actual Unit Sales	99,000,000
Allowed Revenues (from above)	$10,000,000
Required Total Price	$0.10101/Unit
Decoupling Price "Adjustment"	$0.00101/Unit

In any period after the rate case, actual sales will almost certainly be different than the test year sales. Decoupling automatically accounts for this deviation by recalculating the price – Price is equal to the Allowed Revenue divided by *Actual* Unit Sales. In the example, sales are assumed to have declined by 1 million units and the resulting price is

[23] The entirety of the calculations and methodologies discussed here relate solely to the non-commodity portion of the utility's cost of service and of the customers' bills.

$.10101 per Unit of Sales, or $0.00101 higher than the price originally set in the rate case.

2. Revenue-per-Customer Decoupling

As a practical matter, between rate cases most of the utility's non-commodity costs do not change and can be considered fixed.[24] However, some costs, mostly related to distribution system expansions plus metering and billing to serve new customers, do change with the number of customers being served. Revenue-Cap Decoupling can be modified to reflect this, using a form of decoupling referred to as Revenue-per-Customer ("RPC") Decoupling.

RPC Decoupling begins with a traditional rate case and prices are set in the usual manner, using traditional rate design techniques. Based on the adjusted test year values in the rate case, average revenue-per-customer values for each rate class can be easily computed. This calculation uses the same values used to compute the prices set in the rate case. For each rate class, RPC values are calculated for each volumetric rate and for each billing period.[25] While this calculation is not usually done in a traditional rate case, it is easily derived from data found in the rate case. The average revenue per customer is separately derived for each month, for each rate class and for each applicable volumetric rate ($/kWh and $/kW, or $/therm) for each rate class. With the RPC calculations in hand, the allowed revenues for any post-rate case billing period can be calculated by multiplying the RPC value by the actual number of customers, resulting in the RPC allowed revenue. Table 4 demonstrates the adjustment which is made to the allowed revenue. The addition of 500 customers increases the allowed revenue by $25,000.

Table 4
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Number of Customers	200,000
Revenue Per Customer (RPC)	$50.00
Post Rate Case Calculation	
Number of Customers	200,500
Allowed Revenues (=$50 * 200,500)	10,025,000
Actual Unit Sales	99,225,000[26]
Required Total Price	$0.101033/Unit
Decoupling Price "Adjustment"	$0.001033/Unit

[24] From an accounting perspective, the only utility costs actually deemed "fixed" are depreciation and interest expense. When under financial stress, utilities can reduce costs that otherwise appear unvarying in the short run. For example, they can (and do) defer maintenance, defer capital programs, suspend line-clearing activities, change billing frequency, and even omit dividends and lay off employees when circumstances warrant.

[25] While we often think of utility bills as being rendered on a monthly basis, utilities actually render bills on a billing cycle basis, which spreads the meter reading and printing of bills over the entire month. There are usually 20-22 billing cycles in a month (one for each non-weekend day).

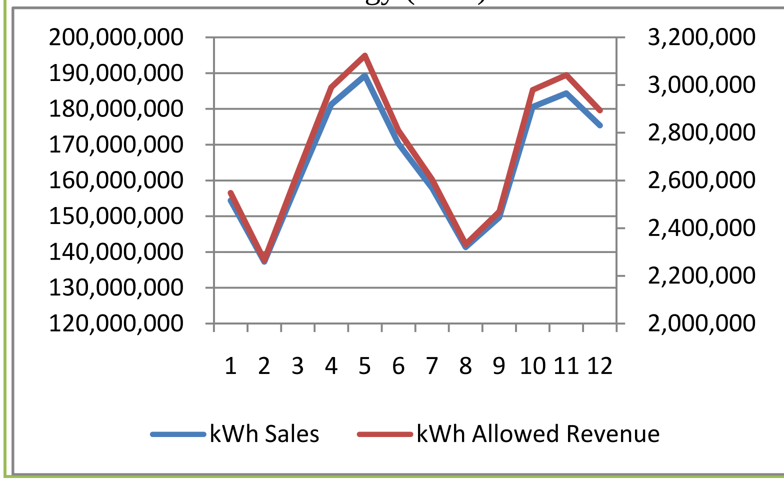
[26] Here we have assumed that new customers use, on average, 450 units each, rather than the "old" customer average of 500 units.

From this point, the recalculation of prices is accomplished in the same manner as with revenue-cap decoupling. The RPC allowed revenues are divided by the actual unit sales, to derive the new price – in the example, $0.101033/Unit.

3. Application of Decoupling – Determination of Allowed Revenues

Both revenue-cap decoupling and RPC decoupling adjustments are applied to the volumetric prices of each rate class. Table 5 reflects the seasonal nature of consumption and revenues using actual data from PPL, an electric utility in Pennsylvania.[27]

Table 5
Seasonal Nature of Energy (kWh) Sales and Revenues



Using consumption based on billing cycle data, allowed revenue values are calculated for each period. In this example, the kWh allowed revenues are shown. For rate classes with demand charges, comparable data would be used to calculate kW allowed revenues. Under revenue-cap decoupling, the allowed revenue for each billing cycle would remain essentially constant between rate cases. Under RPC decoupling, a separate revenue per customer value is calculated for each volumetric price and is then used to adjusted the allowed revenue in each post-rate case period. The calculation should be performed on a billing cycle basis because the underlying data in the rate case are based on billing cycle data.

4. Application of decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased power adjustment clause for electric utilities and the gas purchase adjustment clause for gas utilities. In both of these cases, utilities compute the actual costs for these items and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral

[27] In this case, the Test Period began on October 1 (month 1) and ran to September 30 (month 12). Here the data was provided on a monthly basis, rather than on a billing cycle basis.

account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result is a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility.

Unlike commodity adjustment clauses, however, there are no forecasting components involved in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. In order to calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. In order to calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers) and then divide that number by Actual Unit Sales. In either case, *all* of the information needed to make the calculation is known at the time customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current, rather than an accrued, basis. This also means that there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test year normalized results, except to calculate a daily or monthly RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle. For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

5. Application of RPC Decoupling: New v. Existing Customers

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies. As illustrated in Table 6, if new customers, on average, use 450 kWh in a billing period but the rate case derived RPC for existing customers was 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed nor used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, while the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6			
	Existing Customers	**New Customers**	**Total**
Number of customers	200,000	500	200,500
RPC Value	$50.00	$50.00	
Allowed Revenues	$10,000,000	$25,000	$10,025,000
Average Unit Sales	500	450	
Decoupled Price (from Table 4)	$0.101033	$0.101033	$0.101033
Collected Revenues	$10,002,267	$22,733	$10,025,000
Per-Customer Contribution	$50.5165	$45.46	$50.00

To correct for this, a separate RPC value can be calculated for new customers – in our example, the amount would be $45.00 for new customers. As shown in Table 7, the RPC allowed revenues would be not increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

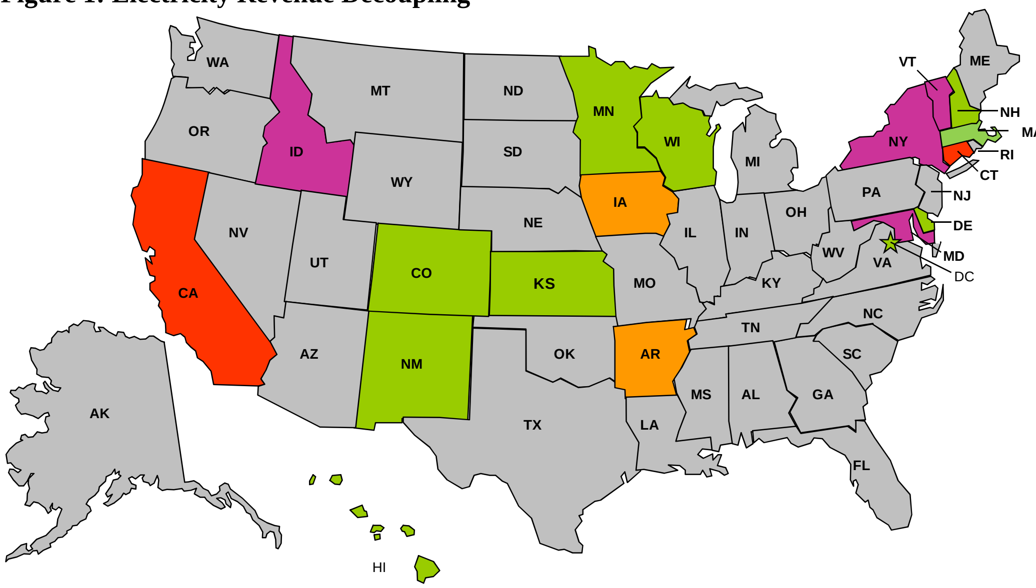
This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.99.

Table 7			
	Existing Customers	**New Customers**	**Total**
Number of customers	200,000	500	200,500
RPC Value	$50.00	$45.00	
Allowed Revenues	$10,000,000	$22,500	$10,022,500
Average Unit Sales	500	450	
Decoupled Price ($10,022,500 ÷ 99,225,000)	$0.1010101	$0.1010101	$0.1010101
Collected Revenues	$10,00,000	$22,500	$10,022,500
Per Customer Contribution	$50.00	$45.00	$49.99

D. Current Experience with Gas and Electric Decoupling

Figures 1 and 2 summarize the current status of electric and gas decoupling in the United States. In the subsections that follow, activities in selected states are described in more detail.

Figure 1: Electricity Revenue Decoupling[28]



LEGEND

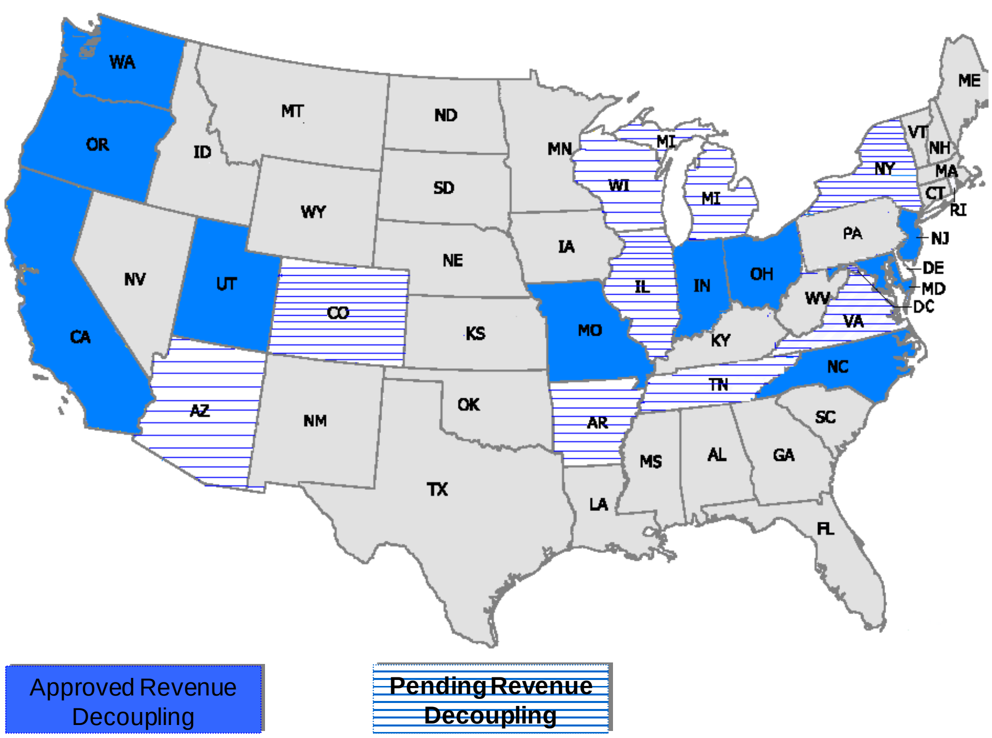
States where all electric IOUs are decoupled, or must be decoupled in near future (CA, CT)

States where at least one electric IOU is decoupled (ID, MD, NY, VT)

States considering decoupling (docket or investigation opened, or utility has filed proposal) (CO, DC, DE, HI, KS, MA, MN, NH, NM, WI)

States where commission has indicated it will consider decoupling proposals (AR, IA)

Figure 2: Natural Gas Revenue Decoupling[29]



---

[28] Regulatory Assistance Project, April 2008

[29] American Gas Association, presentation to NARUC, 17 July 2007.

1. California

California is the state with the longest history with decoupling. It has been in place for natural gas utilities for almost 30 years, and for electric utilities for the same period, with a multi-year suspension during the restructuring era.

California decoupling is only one small part of a complex regulatory framework in California that includes as many as seventeen different adjustment mechanisms that operate between general rate cases.

California's decoupling system is a simple revenue cap, with the allowed distribution revenue requirement from the general rate case trued up without consideration of inflation, customer growth, or other factors. However, this is accompanied by use of a future test period in the rate case, an "attrition" case between rate cases that captures inflation and productivity adjustments as well as impacts of growth, and annual adjustment of the return on equity.

2. Washington

Washington experimented with electric decoupling beginning in 1990, with a mechanism for Puget Sound Power and Light Company (now Puget Sound Energy). The Puget mechanism divided costs into "base costs" which were adjusted annually on a revenue per customer basis, and "resource costs" which were adjusted annually to reflect changes in actual power supply costs, both fixed and variable. The mechanism was terminated after four years, primarily due to the rising level of resource costs.

Washington has recently approved partial and limited decoupling mechanisms for Cascade Natural Gas Company and Avista Utilities natural gas service.

The Cascade mechanism was adopted in January, 2007, and recalculates revenues based on normal weather conditions prior to determining if a decoupling adjustment is required. Because it does not protect the utility from earnings volatility caused by variations in weather, the Commission chose not to impose a cost of capital adjustment. It was approved for an initial three-year period.

The Avista mechanism is even more limited. Not only are sales restated to reflect normal weather, but new customer usage is completely excluded from the decoupling mechanism. This reflects evidence that much of the decline in usage per customer is caused by lower use by new customers, and that is accounted for in the utility's line extension policy. The Avista mechanism was approved for an initial three-year period.

3. Oregon

Oregon approved a revenue-per-customer decoupling mechanism for Northwest Natural Gas in 2002, and expanded and extended it in 2005. Initially, the mechanism only allowed recovery of 90% of margin declines caused by lower sales. The Commission required a formal evaluation of the NWNG mechanism, prepared by Christensen Associates, which concluded, among other things, that decoupling was a primary contributor to a bond rating upgrade for NWNG. As a result of the 2005 review process, the NWNG mechanism was modified to provide for 100% recovery of margin declines, and extended to 2009.

In 2006, the Oregon PUC approved a settlement with Cascade Natural Gas implementing a full revenue-per-customer decoupling mechanism. It does not make use of a "K" factor nor does it provide for separate treatment of new customers.[30] While the Commission did not order a cost of capital adjustment, Cascade agreed to donate 0.75% of revenues, from shareholder funds, to the Energy Trust of Oregon for energy efficiency programs; this is approximately equal to the effect of a 2% reduction in the equity capitalization rate. An additional 0.75% of revenues from an energy efficiency surcharge is also transmitted to the ETO.

4. Idaho

The Idaho PUC approved a two-part decoupling mechanism in 2007 for Idaho Power Company. The first part is a fixed cost per customer for delivery services. The second part is a fixed cost per unit of energy, attributable to power supply. This is a limited decoupling mechanism, with sales adjusted to reflect normal weather prior to calculation of the decoupling adjustment. Any surcharge or surcredit is reflected on the customer bill as part of the energy conservation program charge. Rate increases of more than 3% are not allowed (but, with weather restated to normal, it is pragmatically unlikely that any adjustment would reach this magnitude).

5. Utah

In 2006, the Utah Public Service Commission approved a three-year pilot full decoupling mechanism for Questar Natural Gas Company, without a K factor or separate treatment of new customers. The Commission did not order a cost of capital adjustment, but did require that Questar begin the deferral accounting (for the decoupling adjustments, both up and down) with a $1.1 million credit in the customer's favor.

6. Maryland

Baltimore Gas & Electric Company (BGE) currently operates under a full decoupling program for its residential and general service gas customers. It is a simple revenue-per-customer (RPC) mechanism, based on a rate case test-year revenue requirement. The RPC is expressed as a function of average usage per customer per month. Revenue adjustments are made monthly, and any difference between actual and average use per month is reconciled in a future month.

In 2007, the Maryland Public Service Commission approved the decoupling proposal ("Bill Stabilization Adjustment Rider") of the Potomac Electric Power Company (Pepco). Like BGE's, it is a full decoupling, revenue-per-customer program. Adjustments are

[30] A "K" factor can be built into a decoupling mechanism to adjust for other factors that policymakers may deem important, e.g., trends that would have affected the revenues that the utility would have received under traditional regulation. A "K" factor can be linked to expected changes in average use per customer. It doesn't reward or penalize the utility for changes in usage – instead, it is intended to eliminate the risk of a predictable windfall or loss.

made monthly, capped at ten percent, with any excess carried over to a future period.[31] In recognition of the reduced risks that Pepco would face, the Commission lowered the company's otherwise allowed return on equity by 50 basis points. It also approved a similar decoupling proposal for Delmarva Power (which, like Pepco, is a wholly-owned subsidiary of Pepco Holdings, Inc.).

a) MADRI

The Mid-Atlantic Distributed Resources Initiative (MADRI), a cooperative effort of state regulators in New Jersey, Delaware, the District of Columbia, Maryland, and Pennsylvania,[32] developed a generic approach to decoupling, referred to as the Revenue Stability Model Rate Rider. It describes the mechanics of a full revenue-per-customer decoupling regime, and it was based largely on the BGE program. It in turn became the model for the Pepco and Delmarva plans.[33]

7. North Carolina

North Carolina's three major gas utilities were decoupled in November 2005. The Public Utilities Commission based its decision to do so on several findings: one, conservation has the potential to cause financial harm to the utility and its shareholders; two, decoupling offers better opportunities for the conservation of energy resources and savings for customers, thereby putting downward pressure on wholesale gas prices; three, decoupling better aligns the interests of the utility and its customers; and, four, it reduces shareholder risk.

The PUC approved the decoupling mechanism as an experimental tariff – the Customer Utilization Tracker (CUT – and limited it to no more than three years unless reauthorized by the PUC. It is a full revenue-per-customer decoupling mechanism for residential and commercial customer classes, adjusted semi-annually. The Commission excluded industrial customers from the CUT, reasoning that their different usage patterns provided good cause to do so. The PUC required that the utilities make significant contributions toward conservation programs, and rejected the Attorney General's argument that decoupling would penalize customers for conserving. Lastly, the Commission recognized the importance of volumetric rate structures and lower fixed customer charges. It rejected the "straight fixed-variable" rate design proposal, with its higher fixed charges, on the ground that customers' bills should be tied to their usage.

---

[31] This is a very high cap and it is not expected to be reached. Adjustments have so far averaged well below one percent.

[32] "The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection." http://www.energetics.com/MADRI/.

[33] The Model Rider can be found at http://www.energetics.com/MADRI/regulatory_models.html. The revenue-per-customer approach to decoupling was first developed by RAP principals in the early 1990s.

8. New Jersey

New Jersey Natural Gas Company and South Jersey Gas Company proposed full revenue-per-customer decoupling mechanisms in 2005. The mechanisms would have covered the revenue impacts resulting from sales deviations due to normal weather, energy efficiency, and other factors (e.g., economy). The difference between actual revenues and allowed revenues (the product of number of customers, average usage/customer, and price) would be recovered (or credited) through the new Conservation and Usage Adjustment (CUA) clause in the following year.

The cases were settled in 2006. Limited revenue-per-customer decoupling for non-weather-related sales changes only was approved. It is called the Conservation Incentive Program (CIP), and is being run as a three-year pilot. Revenue adjustments cannot exceed the amount by which the company reduces total costs of Basic Gas Supply Service (i.e., the commodity savings that result from company investments in energy efficiency). Revenue shortfalls that are in excess of the gas supply savings can be recovered in later periods, to the extent that there is room under the cap to do so. Company-sponsored energy efficiency programs were greatly expanded, but, in an interesting twist, the settlement called for the costs of efficiency programs to taken "below the line" (i.e., not included in the regulated cost of service, but rather paid for out of company earnings. This had the effect of reducing the companies' returns on equity, in recognition of the reduced risk that they would now face.

9. Vermont

At the end of 2006, the Vermont Public Service Board approved a modified revenue cap (partial decoupling) for Green Mountain Power Corporation (GMP), a vertically integrated electric company. GMP's allowed base revenues (non-power costs) will be pre-determined for each of the three years of the program, in accordance with the terms of a memorandum of understanding signed by the utility and several parties. Changes in base revenues are capped at $1.25 million for 2008 and $1.5 million for 2009, although the caps can be exceeded, if necessary, for specified exogenous costs. The company's earnings are bounded by sharing collars: the first 75 basis points, up or down, are borne by GMP; the next 50 basis points are shared half-and-half between the company and its customers; and anything after that is borne by the customers. The company's power costs are subject to a quarterly fuel adjustment clause. Variances in costs of committed resources (owned units or contractual entitlements) are borne entirely by the customers. Variances up to $400,000 per quarter for non-committed (i.e., market) resources are covered by the company. Variances in excess of the $400,000 are covered by customers. However, if the total variance would result in an adjustment of greater than $0.01/kWh, the excess will be carried over to a following quarter.

E. Cost-of-Capital Impacts of a Lower Equity Ratio

The cost of capital is a function of the cost of common equity, the cost of debt, the proportion of each used to finance the utility, and the tax rates to which each are subject. While equity is subject to income tax, interest on debt is deductible for income tax purposes. Therefore equity in a utility capital structure is much more expensive to consumers than debt.

Under decoupling, utility financial risk is reduced, since earnings no longer vary with weather or other causes of sales variation. Because earnings are more stable, utilities can have a more leveraged capital structure, and still retain the equivalent bond rating.

The calculation below, which includes tax effects on both debt and equity, shows how a 3% reduction in the equity capitalization ratio produces about a 3% reduction in the return and taxes needed to support the utility rate base.

Cost of Capital Impacts			
Without Decoupling	**Ratio**	**Cost**	**Weighted With-Tax Cost of Capital**
Equity	**45%**	**11.0%**	**7.62%**
Debt	**55%**	**8.0%**	**2.86%**
Weighted Cost			**10.48%**
Revenue Requirement: $1 Billion Rate Base			**$ 104,800,000**
With Decoupling			
Equity	**42%**	**11.0%**	**7.11%**
Debt	**58%**	**8.0%**	**3.02%**
Weighted Cost			**10.13%**
Revenue Requirement: $1 Billion Rate Base			**$ 101,280,000**
Savings Due to Decoupling Cost of Capital Benefit:			**$ 3,520,000**

F. Elasticity Impacts of Straight Fixed/Variable Pricing

The table below shows how straight fixed/variable pricing affects the amount of natural gas a utility would be expected to sell.

The basic assumptions for the sales volumes and costs are quite simple; the utility has 100,000 customers, and an annual revenue requirement of $130 million.

Under SFV pricing, the rate design would be $30 per month plus $1.00 per therm, while with volumetric pricing, the rate design would be a flat $1.30/therm for all gas used.

Volumetric pricing would increase the customer's rate per therm by 30%.

Based on an assumed long-run arc elasticity (elasticity over a significant change in price) of 0.50, a conversion from SFV to volumetric pricing would be expected to produce an 18% reduction in total gas sales.

Estimates of elasticity for natural gas are measured on both a short-run and long-run basis. In the short-run, elasticity is typically very low, on the order of -0.05 to -0.15, while in the long run (when customers can buy new appliances, insulate homes, and convert fuel sources) the elasticity is much higher, in the range of -0.020 to -0.070.

The selection of -0.50 as a long-range arc elasticity for natural gas is for illustrative purposes only, and not intended to be representative of the elasticity of demand for gas on any particular natural gas utility. At least one study supports this assumption.[34]

[34] Price Elasticity of Demand, Mackinac Center for Public Policy, 1997 http://www.mackinac.org/article.aspx?ID=1247

Hypothetical Gas Utility

Customers			100,000
Annual Sales	Therms		100,000,000
Annual Revenue Requirement		$	130,000,000

Rate Design With Straight Fixed Variable Pricing			
Customer Charge	$/month	$	30.00
Annual Customer Charge Revenue		$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Revenue	$/year	$	136,000,000

Rate Design With Volumetric Pricing			
Therms Sold	Therms/year		100,000,000
Distribution Rate	$/therm	$	0.36
Distribution Revenue	$/Year	$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Rate	$/Therm	$	1.36
Total Revenue	$/year	$	136,000,000

Therm Savings From Volumetric Pricing			
Unit Price, SFV Pricing		$	1.00
Unit Price, Volumetric Pricing		$	1.36
Change in Price/Therm			36%
Assumed Long-Run Arc Elasticity			-0.50
Estimated Elasticity Response			18%

Bill Impact of SFV Pricing					
Usage		Volumetric		SFV	Difference %
10	$	13.60	$	40.00	194%
50	$	68.00	$	80.00	18%
100	$	136.00	$	130.00	-4%
200	$	272.00	$	230.00	-15%
300	$	408.00	$	330.00	-19%