Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives

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CONTENTS

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EXECUTIVE SUMMARY

Soaring fuel prices, growing concerns about utility system reliability needs, and increasing awareness of future environmental risks have all reinvigorated interest in the use of energy efficiency as a serious utility system resource. With this renewed interest, there is increasing recognition that in order to expect utilities to embrace the aggressive deployment of energy efficiency programs, something must be done to address the financial concerns utilities have regarding energy efficiency. As a result, a growing number of states are re-examining utility regulations and policies that affect utility planning, decision-making, and operations to ensure that such policies and regulations are supportive of energy efficiency objectives.

Electric utility industry experts have long recognized that under typical regulatory structures (e.g., traditional rate-of-return regulation, rate caps, etc.), utilities do not have an economic incentive to provide programs to help their customers be more energy-efficient. In fact, they typically have a disincentive because reduced energy sales reduce utility revenues and earnings. The financial incentives are very much tilted in favor of increased electricity sales and expanding supply-side systems.

This report examines recent experience with two key regulatory approaches to overcome these structural disincentives: (1) "decoupling" of utility revenues and profits through periodic "true-up" of actual to projected sales; and (2) providing shareholder "performance incentives" for achieving energy efficiency program objectives. These basic concepts are not new. In the 1980s and 1990s during the era of "integrated resource planning," a number of states enacted such policies. However, the advent of the utility restructuring movement greatly diminished interest in such policies and regulations; most of them were dropped in the mid- to late 1990s. The growing need for energy efficiency as a resource to help meet utility system needs has renewed interest in these regulatory approaches. Our review of these recent experiences includes case studies of states or individual utilities where either decoupling or shareholder performance incentives have been enacted.

We found that despite the surging interest in regulatory decoupling, there are thus far relatively few cases where such an approach has been enacted and effectively implemented for a sufficient period of time to begin to assess results. The states of Oregon and California are the primary leading examples. We also found a small set of cases in which decoupling has been enacted on a "pilot" or other more limited basis, but there has not been sufficient experience to observe possible effects on energy efficiency activity. These examples include Maryland, New Jersey, North Carolina, Utah, and just recently, Ohio. Lastly, we identified several other states that are actively considering such an approach, including Idaho, New York, and Washington.

We also found that the use of some type of shareholder or related "performance incentives" is more widespread than decoupling at this point. Several states have had such mechanisms in place for a number of years, including Massachusetts, Rhode Island, Connecticut, Vermont, and Minnesota. Nevada has recently enacted a performance incentive for its electric utilities. We found a few additional examples where such mechanisms are either more limited in scope or have just recently been adopted.

Experience to date suggests that the results from enacting either of these regulatory mechanisms has generally been very positive, with the utilities or other program providers governed by such mechanisms often demonstrating strong commitments to meet or exceed established goals for their energy efficiency programs. With the rapidly increasing interest in expanding energy efficiency as a utility system resource we expect, and recommend, further adoption of regulatory mechanisms to address utility financial concerns regarding energy efficiency. We intend to continue monitoring these developments and produce a further assessment later in this decade.

INTRODUCTION

The need for greater levels of energy efficiency in our society has never been more evident than it is today. For policymakers, high energy costs faced by citizens and businesses; growing environmental concerns; domestic resource depletion; and even national security factors all contribute to a heightened awareness of the need for energy efficiency. Consequently, there is marked and growing interest across the nation in expanding utility energy efficiency efforts as a key element in a many pronged strategy to improve the energy efficiency of the economy.

Within the utility industry, interest in energy efficiency has never been greater. Indeed, the industry faces a "perfect storm" of high fuel prices, escalating construction costs, increased uncertainty surrounding cost-recovery for new generation plants, mounting concerns around system reliability,[1] public opposition to the siting of new generation and transmission facilities, and looming environmental costs—particularly potential carbon emissions costs. In these circumstances, energy efficiency has become increasingly perceived as a viable—even preferred—resource option because of its unique attributes in positively addressing all these concerns.

As an example of the national consensus developing around the importance of advancing energy efficiency, a group of more than 50 leading organizations (utilities, state governments, major customers, and nonprofit organizations) recently crafted a *National Action Plan for Energy Efficiency* (U.S. DOE and EPA 2006). This jointly developed plan contained a significant focus on the need for energy efficiency as a utility system resource. The plan has been formally endorsed by the national trade associations for both the electricity and natural gas industries.[2]

Fortunately, the record of successful implementation of energy efficiency programs in leading states demonstrates that energy efficiency is a practical and cost-effective resource. Over two decades of experience with energy efficiency programs have shown that energy efficiency savings ("negawatts") are real and cost-effective—these savings can be measured and relied upon to deliver savings as projected and needed. The contribution of such resource savings has been significant in many states and regions, yielding both economic and environmental benefits (York and Kushler 2005).

For all of these reasons, utilities, regulators, and policymakers alike are taking a serious look at what policy and regulatory actions might be necessary to facilitate a significant expansion of utility-sector energy efficiency efforts. In particular, this has focused on regulatory mechanisms that would address utility disincentives and/or provide positive incentives for

[1] As this report went to press, the North American Electric Reliability Council (NERC) had just released its annual report (NERC 2006), which concluded that several regions of the U.S. would likely fall below target reliability levels over the next two or three years. The report called for a variety of supply- and demand-side actions to address this problem, including financial incentives to reward customers' installation of energy efficient equipment.

[2] This was done through a joint letter to the National Association of Regulatory Utility Commissioners (NARUC) from the American Gas Association, Edison Electric Institute, and Natural Resources Defense Council, July 2006.

utilities to pursue energy efficiency. Such mechanisms were in place for a relatively brief period in a number of states during the late 1980s and early '90s—the era of integrated resource planning (IRP) and demand-side management (DSM) (Eto, Stoft, and Belden 1994; DiValentino et al. 1992). However, as the wave of restructuring rolled over the U.S. in the mid- to late '90s, most of these mechanisms were eliminated along with the regulatory structures and requirements that had been in place for IRP and DSM (Kushler, York and Witte 2004).

Industry experts have long recognized that under traditional rate-of-return regulation, utilities do not have an economic incentive to provide programs to help their customers be more energy efficient. In fact, they typically have a disincentive because reduced energy sales reduce utility revenues and profits. Under traditional rate-of-return regulation, utilities' earnings are based on the total amount of capital invested in selected asset categories (such as transmission lines and power plants) and the amount of electricity (kilowatt-hours) sold.[3] The financial incentives are very much tilted in favor of increased electricity sales and expanding supply-side systems (Harrington et al. 1994).[4]

In this report, we examine recent trends and experience with regulatory reforms aimed at removing disincentives and providing positive incentives for utilities to promote and assist customers in achieving greater energy efficiency. The first part of this research was a review of available literature and written documentation about recent state activities addressing such regulatory changes. ACEEE then supplemented this literature review with direct surveys of state regulatory agencies, utilities, and other appropriate parties in states with active utility-sector energy efficiency programs.

In the beginning of the report, we provide some background about how energy efficiency programs affect the economics of utilities, and briefly describe some of the basics underlying the regulatory mechanisms that have been adopted in various jurisdictions to address utility economic concerns regarding energy efficiency. In the next sections we describe the scope of the research and present summary findings. We then present a discussion of our key results and our conclusions.

This report includes three appendices of state profiles of the key regulatory reforms that we present and discuss in the main body of the report. Appendix A includes profiles of states that have enacted some type of performance—or shareholder—incentives for their energy efficiency programs. Appendix B includes profiles of states that either have recently enacted decoupling mechanisms or that are actively investigating and considering such proposals (and in a few cases, recently concluded such investigations). Finally, Appendix C presents a

[3] While this relationship is clearly true for investor-owned utilities, the same basic dynamic also affects publicly owned utilities, where lower sales reduce total revenues and can adversely impact fixed-cost recovery and other revenue-based objectives.
[4] The same basic economic forces affect natural gas utilities as well. Moreover, on the natural gas side, an additional complicating factor is the recent general trend for many utilities toward stagnant or declining gas sales per customer. Adding energy efficiency responsibilities to natural gas utilities in this context without solving the connection between losses and sales would be particularly stressful to the financial health of these companies.

more detailed case study description of two leading examples of these mechanisms: shareholder incentives in Massachusetts and decoupling in Oregon.

BACKGROUND

In order to understand the need for regulatory mechanisms to facilitate utility-sector energy efficiency programs, it is useful to have some background on the nature of utility regulation and how it tends to influence utility decision-making regarding energy efficiency.

Traditional Utility Ratemaking Provides a Disincentive for Utilities to Provide Customer Energy Efficiency Programs

Under traditional regulation, a utility's rates are set based on an estimation of costs of providing service over some period (including an allowed rate of return) divided by an assumed amount of unit sales over that period. If actual sales turn out just as projected, the utility will recover all of its fixed costs and earn its allowed rate of return. If actual sales exceed the projection, the utility will earn extra return. If actual sales fall below the projected amount, the utility will earn less return and may potentially fail to recover all of its fixed costs.

This basic relationship between sales levels and utility financial objectives applies to both gas and electric utilities, and exists whether the utility is a vertically integrated utility or a "distribution-only" utility in a restructured state. (Incidentally, this basic relationship is the source of much argument and "gamesmanship" over adopting a sales forecast in a traditional rate case.)

Rationale for Regulatory Mechanisms to Facilitate Utility-Sector Energy Efficiency Programs

The public interest issue underlying the concept of regulatory mechanisms for energy efficiency is really quite simple. Once rates are set, utilities have an inherent incentive to increase sales, and a disincentive to take actions to encourage their customers to adopt energy-efficient practices that may result in lower sales, as this will reduce their fixed cost recovery, and thus (for investor-owned utilities) their amount of profit or (for publicly-owned utilities) their creditworthiness and their capacity to meet non-power obligations from net revenues. This disincentive affects not only utility interest in directly funding and delivering energy efficiency programs to their customers, but also their institutional interest regarding other public policy initiatives promoting energy efficiency, such as improved building codes, new equipment and appliance standards, or even a broad public appeal to reduce energy use to help combat global warming (Bachrach and Carter 2004).

As a result of this basic conflict between the utility interest in higher unit sales and the public interest in advancing energy efficiency, a number of states have experimented with alternative mechanisms designed to modify the economic effects of energy efficiency on the utility. These include such things as providing economic incentives to utilities for delivering successful energy efficiency programs as well as mechanisms to "decouple" fixed cost recovery and profit from the level of customer energy use (Regulatory Assistance Project 2005, 2006; U.S. EPA 2006).

Regulatory Mechanisms in Context: Utilities Have a Range of Financial Concerns Regarding Energy Efficiency

Experience within the utility industry over the past several decades indicates that there are essentially three key areas of financial concern that utilities have[5] regarding the funding and operation of energy efficiency programs:

(1) Assuring cost recovery for the direct costs of a program,
(2) Addressing the disincentives of "lost revenues" (or "lost sales") resulting from energy efficiency improvements that reduce customer energy use, and
(3) Providing an opportunity for shareholder earnings from good performance in providing programs and services for customer energy efficiency.

Ideally, all three of these concerns should be addressed by regulatory commissions. (However, it is true that in practice, states have often developed specific mechanisms for one or two of those elements and considered that "good enough.") The following material briefly discusses each of these three areas of concern and some of the mechanisms that have been used to address them.

Program cost recovery. Of the three areas of utility financial concern, experience suggests that the most important initial hurdle (and a key threshold requirement for utility energy efficiency programs) is #1: cost recovery for the direct costs of programs. There are several different ways for utilities to recover program costs; the three most prevalent are:

- costs embedded in rates as part of the utility's resource procurement budget (just as they are for supply-side resources);
- special tariff riders approved in regulatory proceedings; and
- public purpose surcharges on the bill (e.g., legislatively mandated "system benefits" charges).

Essentially every state that has utility-sector energy efficiency programs has adopted some form of one of those three mechanisms, and there is considerable experience successfully operating those mechanisms. A related factor that also influences utilities' willingness to fund and implement programs is the certainty of cost recovery. This is a risk factor that can be diminished in a couple of ways. One is some type of regulatory review of programs prior to implementation. This would not be pre-approval of program expenses, but rather a reasonably rigorous technical review of proposed programs and program designs so that the utility implementing the programs has sufficient guidance from regulators that the programs

[5] This presumes that the utility is considering the prospect of actually funding and administering energy efficiency programs themselves. In situations where utilities are not considering or are precluded from such roles (e.g., utilities merely collect system benefit charge revenues and pass them along to a third-party administrator), then the first and third financial concerns do not apply to the utility (but would apply to whatever entity is administering the energy efficiency programs).

are on track. The other way of reducing such risk is simply establishing a solid track record of regulatory review and approval of program expenses. This can only occur with sufficient funding and program cycles, but a utility in its tenth year of program operations is likely much more secure in getting cost-recovery approved than a utility initiating its first set of programs.

Lost sales revenues. The second area of concern, addressing “lost revenues,” has tended to be the most difficult to implement. Early efforts to address this issue often focused on directly reimbursing utilities for the revenues lost due to reduced sales resulting from specific energy efficiency programs. However, that approach turned out to be problematic, for several reasons. Critics point out that the mechanisms create perverse incentives since the most profitable programs will be those that look best on paper and save the least actual energy in practice. Moreover, given the extended duration of savings from most programs, “lost revenue” recoveries are guaranteed to escalate over time as previous years’ savings build on current-year program impacts, with what in some cases have become politically unsupportable overall rate impacts. In addition, directly compensating for revenue losses from specific programs does nothing to address the utility’s disincentive to support broader policy initiatives to improve efficiency (e.g., codes and standards), nor does it help mitigate the broader utility interest in pursuing load building.

As a result of these factors, mechanisms to directly reimburse for specific program lost revenues have fallen from favor. Several states have had such mechanisms in the past, but these practices have generally ended. “Lost revenue” recovery remains a concern to utilities and their regulators, but we observed that commissions appear to be addressing this through decoupling mechanisms and/or performance incentives.

In the simplest terms, “decoupling” refers to a rate adjustment mechanism that “decouples” the ability of the utility to recover its agreed-upon fixed costs (including allowed earnings) from the actual volume of unit sales that occur. There are a number of variations in how the computations can be done (e.g., normalizing for weather, adjusting for the number of customers, etc.), but the basic principle is that a “true-up” mechanism is applied once actual sales levels are known. The true-up mechanism is symmetrical. That is, if sales were lower than forecasted (for whatever reason, including energy efficiency), then a slight upward adjustment in rates is applied to compensate the utility. Conversely, if sales were higher than forecasted, a slight rate decrease is implemented to compensate customers. Under nearly all reasonable circumstances, these “adjustments” should be very small (e.g., between 0% and 3%), but to ensure that is the case, some jurisdictions have applied “caps” on the possible adjustment to limit its magnitude (e.g., limit any adjustment to no more than 2% or 3% of the existing rate).

Performance incentives. The use of performance incentives (also known as “utility incentives” or “shareholder incentives”) is a commonly used approach in states that have any mechanisms in place beyond program cost recovery. This has tended to be the most common because it is usually easier to accomplish than lost revenue recovery mechanisms. It also has often been generally regarded as helping to address both lost revenues and the desire by utilities to be able to “earn a return” on their energy efficiency activities (these two concerns are sometimes lumped together and simply referred to as the utility's "financial concerns").

Again, there are many specific approaches that have been used to provide financial incentives that reward utilities for successfully reaching or exceeding program goals. These include:

- allowing utilities to earn a rate of return on energy efficiency investments equal to supply-side and other capital investments,
- providing utilities an increased rate of return either on the energy efficiency investment specifically or overall utility investments,
- providing utilities with a specific financial reward for meeting certain targets, and
- providing utilities with an incentive equal to some proportion of the overall net benefits the programs produce (i.e., "shared savings").

Positive financial incentives have sometimes been balanced with negative financial penalties for poor performance or refusal to implement programs.

As utilities and related organizations seek to increase the savings and associated benefits from energy efficiency programs, it is advantageous to address disincentives from energy efficiency improvements, as well as consider positive incentives for reaching or exceeding established goals for such programs (Carter 2001). In this report we examine state experiences with approaches to removing disincentives and/or implementing positive incentives for successful energy efficiency program implementation.

SCOPE OF THE RESEARCH AND REPORT

This report presents research performed by ACEEE to identify and describe cost recovery mechanisms and regulatory incentives used in conjunction with utility-sector energy efficiency programs. ACEEE reviewed available literature and conducted surveys with staff from selected state regulatory commissions and other industry contacts. The focus was to identify and provide summaries of innovative approaches and successful models for providing incentives to regulated utilities for achieving energy savings through successful energy efficiency programs.

We surveyed states that fall into two primary categories:

(1) States that have not restructured their utilities. In these states, investor-owned utilities retain primary resource planning and acquisition responsibilities and are subject to rate and other regulation from state public service commissions (or other regulatory authorities).
(2) States that have restructured their electric utilities, allowing retail choice and removing or sharply constraining utilities’ resource planning. In many of these states, the regulated distribution companies are still required to offer or underwrite energy efficiency programs.

We targeted only those states that either offer or are developing significant energy efficiency programs, and where such programs are administered (and in most cases, implemented) by regulated utilities. We also include a few selected states in which non-utility organizations administer or provide program services. In these cases, there still may be regulatory mechanisms in place or being considered that address removing utility disincentives for energy efficiency. Also, some states have enacted performance incentives for the non-utility organizations administering and implementing energy efficiency programs.

While not a completely exhaustive set of all states offering some kind of energy efficiency programs or other DSM programs through their utilities, we believe we have reviewed the states that demonstrate the greatest commitment and support to such efforts. We include both electric and natural gas utilities, although electric energy efficiency programs are much more prevalent than those for natural gas energy efficiency.

ACEEE reviewed and summarized utility regulatory mechanisms currently in place or under active consideration in states around the nation. This review encompasses both mechanisms to remove the disincentive to energy efficiency (e.g., decoupling) as well as mechanisms to provide a specific incentive to reward good performance in energy efficiency program delivery (e.g., shareholder incentives). Examples of these two primary regulatory mechanisms are addressed in separate sections of this report.

OVERALL FINDINGS

This section presents a brief summary of the overall findings of our research, categorized by the three types of utility economic concerns described above. Following this section, we provide detailed state-by-state summaries.

Program Cost Recovery

We consider this to be an essential factor in order to achieve utility-sector energy efficiency programs. We found at least 25 states with "serious"[6] utility ratepayer-funded energy efficiency programs in operation. All of those states have some type of approved cost-recovery mechanism, and in some cases, combinations of mechanisms (e.g., a public benefits charge plus the ability to recover additional energy efficiency program costs in rates). In this report, we provide summary profiles of 14 states that either have performance incentives or decoupling mechanisms in place (or are being actively proposed and investigated). Of these 14 states profiled, use of a systems benefits charge to fund programs is by far the most prevalent—with nine of those states having such a charge in place.[7] Two states (Idaho and Washington) use a tariff rider on customer rates. Three states (Arizona, Minnesota, and Nevada) use rate case recovery for all program costs. In addition, two of the states with a system benefits charge also use rate cases for either selected utility programs (Wisconsin) or

[6] By "serious" we mean programs that truly attempt to achieve measurable energy savings, including using strategies like providing tangible incentives to customers to improve their energy efficiency. More widespread approaches such as providing "conservation tips" in mailers or on Web sites do not qualify as a "serious" energy efficiency program.
[7] These states are California, Connecticut, Massachusetts, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Wisconsin.

as another general category of program funding (California has both a systems benefits charge and also additional energy efficiency programs to meet resource goals that are addressed through general rate cases). Outside of this group of 14, other states with regulated DSM programs in place often use rate cases or regulatory tariffs to recover program costs (e.g., Iowa, Florida, and Utah).

While the ability to secure cost recovery can be considered a *necessary* condition for achieving utility-sector energy efficiency, it alone is usually not a *sufficient* condition for securing aggressive utility implementation of energy efficiency programs.

Addressing Lost Revenues

There are essentially two basic mechanisms[8] for addressing the issue of sales/revenues "lost" as a result of customer energy efficiency improvements.[9] One is a direct compensation for lost revenues resulting from an energy efficiency program; the other is an overall "decoupling" of revenues from sales.

In the early 1990s, there was a fair amount of focus on the first of these approaches: regulatory mechanisms that specifically compensated utilities for "lost revenues" resulting from their energy efficiency programs. However, in our research for this study we found that this approach has essentially been abandoned. Several states have had such mechanisms in the past, but generally such practices have ended. The movement away from direct reimbursement for lost revenues is likely due to several factors, including: the fact that the approach is vulnerable to "gaming" by over-claiming savings; that it typically leads to very contentious reconciliation hearings as parties argue about the measurement of savings; and that it doesn't do anything to address the utility disincentive regarding broader energy efficiency policies beyond the specific program addressed with the mechanism. "Lost revenue" recovery remains a concern to utilities and their regulators, but we observed that commissions appear to be addressing this either through decoupling mechanisms and/or performance incentives.

"Decoupling" has re-emerged as a mechanism of interest to address lost revenues and to remove the disincentive for utilities to pursue energy efficiency programs. At least seven states now have approved decoupling mechanisms for at least one regulated natural gas or

[8] Actually, our review also identified at least one other regulatory mechanism that has been suggested as a way to address utility concerns about lost revenues, but which appears to be a much less desirable approach. This is the notion of simply increasing the fixed charge (e.g., "monthly charge," "meter charge," etc.) component of the customer bill, so that utility cost recovery is less dependent on sales volume. However, this has the unfortunate effect of reducing the customer incentive to use energy more efficiently because the per-unit price of energy the customer sees is reduced, so this is not recommended as a regulatory mechanism to advance energy efficiency. Although some have termed it so, we do not categorize this "increased monthly charge" approach as "decoupling."

[9] It should further be noted that another approach to this problem has been to use shareholder economic incentives for energy efficiency program performance as a *de-facto* mechanism to help assuage utility management concern about revenues lost from energy efficiency improvements, even though the linkage of the incentive to lost revenues isn't explicit.

electric utility (California, Oregon, Maryland, North Carolina, Ohio, Utah, and New Jersey[10]), and at least another five states are actively considering such mechanisms (Idaho, New Mexico, New York, Vermont,[11] and Washington). The most prominent examples are: (1) California, where decoupling mechanisms are in place for its electric and natural gas utilities; and (2) Oregon, which has a decoupling mechanism in place for its two major natural gas utilities. We discuss these and other examples later in this report.

Shareholder Incentives

We found that the use of shareholder incentives is a commonly used approach in states that have anything in place beyond program cost recovery. This has tended to be the most common because it is usually easier to accomplish than lost revenue recovery mechanisms. It also has often been generally regarded as helping to address both lost revenues and performance incentives (often lumped together and simply referred to as the utility's "financial concerns"). Overall, we found at least seven states with shareholder incentive mechanisms for energy efficiency in place,[12] one state with such incentives under development (California), one state (Wisconsin) that allows one of its utilities to earn a rate-of-return on its energy efficiency programs, and one (Vermont) that has a similar mechanism for a non-utility program administrator.[13] Profiles of the nine states with incentive mechanisms in effect are given later in this report; Table A-1 summarizes these findings.

Again, there are many specific approaches that have been used to provide financial incentives that reward utilities for successfully reaching or exceeding program goals. These include:

- allowing utilities to earn a rate of return on energy efficiency investments equal to supply-side and other capital investments (Wisconsin),
- providing utilities an increased rate of return either on the energy efficiency investment specifically (Nevada) or overall (no current example found—this was used in Michigan in the early 1990s),
- providing utilities with a specific financial reward for meeting certain targets (such as a percentage of program costs—used in Arizona, Connecticut, Massachusetts, New Hampshire, and Rhode Island), and

[10] The New Jersey Board of Public Utilities recently approved two pilot programs for South Jersey Gas and New Jersey Natural Gas that include decoupling mechanisms. This decision happened just as this report was going to press (October 12, 2006). It is a case worth following.

[11] There is a settlement pending between the advocate and Green Mountain Power for a three-year mechanism in Vermont. This occurred too recently for us to include more information about this mechanism in our state summaries. It is another case worth following (Docket Numbers 7175 and 7176 before the Public Service Board, "Green Mountain Power Rate Increase Investigation and Alternative Regulation Plan").

[12] These states are Arizona, Connecticut, Massachusetts, Minnesota, Nevada, New Hampshire, and Rhode Island.

[13] Note: Nine of the 25 states with serious utility-sector energy efficiency programs have those programs administered by entities other than utility companies, thus making utility energy efficiency performance incentives inappropriate. If those states are set aside, then the majority of states with utilities involved in energy efficiency program administration have utility shareholder incentive mechanisms of some type in place or under development.

- providing utilities with an incentive equal to some proportion of the overall net benefits the programs produce (i.e., "shared savings"—used in Minnesota, previously used in a few other states, including California).

Positive financial incentives have sometimes been balanced with negative financial penalties for poor performance or refusal to implement programs.

The appendices present state-by-state descriptions of state experience with utility energy efficiency shareholder incentives and regulatory decoupling mechanisms. These two broad categories of regulatory policy are the focus of this report. However, we also note that there is a set of states in the category of "serious" utility ratepayer-funded energy efficiency programs that have neither shareholder incentive mechanisms nor decoupling mechanisms in place. These states are listed below (with a summary description of program structure):

- Colorado (electric): utility-administered demand-side management programs with traditional regulatory oversight
- Florida (electric): utility-administered demand-side management programs with traditional regulatory oversight
- Illinois (electric): mixed system—negligible energy efficiency through DSM program umbrella; some systems benefits programs; and "clean energy" programs funded through a trust established out of a settlement for sale-of-generation assets
- Iowa (electric and natural gas): utility-administered demand-side management programs with traditional regulatory oversight
- Maine (electric): regulatory administration of state-wide public benefits program
- New Jersey (electric): regulatory administration of state-wide public benefits programs; transitioning away from utility-administered, common platform state-wide programs
- Texas (electric): mandated energy efficiency savings levels, and distributed utility administration of regulatory-approved "program templates"
- Utah (electric): utility-administered demand-side management programs with traditional regulatory oversight

Table 1 presents summary information on cost recovery, lost revenue recovery mechanisms, performance incentive mechanisms, and decoupling for the full set of states we have identified that have serious commitments to energy efficiency in terms of funding and resources that support programs. In the two appendices that follow Table 1, we present profiles of sub-sets of states that (1) have performance incentives in place (Appendix A) and (2) have either enacted decoupling or are seriously investigating and considering decoupling proposals (Appendix B). Finally, in Appendix C we present a more detailed case study description of two leading examples of these mechanisms: shareholder incentives in Massachusetts and decoupling in Oregon.

Table 1. Regulatory Mechanisms for Cost Recovery, Performance Incentives, and Decoupling

State	Cost Recovery	Direct Lost Revenues Recovery	Performance Incentives	Decoupling
Arizona	Yes—Electric rate cases	No	Yes—Capped at 10% of Arizona Public Service's electric energy efficiency program budget. APS's electric EE Plan not yet finalized.	No
California	Yes—Electric and natural gas "system benefits" or "public goods" charge plus additional funding through rates.	No	Under development	Yes—Natural gas and electric
Colorado	Yes—Electric rate cases	No	No	No
Connecticut	Yes—Electric system benefits charge (SBC)	No—Electric distribution companies are only allowed recovery of lost revenues if their earnings are below their allowed rate of return for six months. In addition, in certain regions in Connecticut, the DPUC has introduced a type of lost-revenue recovery mechanism for new CL&M electric load response and distributed generation initiatives.	Yes	No–Electric Partial—Natural gas In CT DPUC Docket 05-05-09, the DPUC rejected enacting any changes to existing rate-making approaches for electric and natural gas utilities. (Electric has no decoupling but two natural gas local distribution companies have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers—a "conservation adjustment mechanism".)
Florida	Yes—Electric rate or tariff rider/ surcharge	No	No	No
Idaho	Yes—Electric rate or tariff rider/ surcharge	No	No	Investigating—Electric

State	Cost Recovery	Direct Lost Revenues Recovery	Performance Incentives	Decoupling
Illinois	Yes—Small-scale electric energy efficiency programs supported by an assessment on electric utilities.	No	N/A—The electric and natural gas energy efficiency programs are administered by the Department of Commerce and Economic Opportunity (DCEO), a state agency.	No
Iowa	Yes	No	No	No
Maine	Yes—Public benefits assessment	No	N/A—Efficiency Maine, a division of the Maine Public Utilities Commission, administers the electric energy efficiency programs.	No
Massachusetts	Yes—Electric SBC	No	Yes—5% (of electric EE expenditures) shareholder incentive for meeting goals	No
Minnesota	Yes—Electric and natural gas cases (based on legislative mandate)	No	Yes—Electric and natural gas	No
Montana	Yes—Electric SBC Yes—Natural gas general rate cases	No	No	No
Nevada	Yes—Electric rate cases	No	Yes—Electric	No
New Jersey	Yes—Electric SBC	No	N/A (NJ is moving to state administration)	No
New Hampshire	Yes—Electric SBC	No	Yes—Electric	No
New Mexico	Not applicable yet; just enacted law that requires utility DSM; cost recovery to be via rate cases.	No	No	No—However a new statute (dealing with both electric and natural gas) calls for removal of disincentives—nothing proposed or in place.
New York	Yes—Electric SBC	No	NA—Electric (NYSERDA administers the electric energy efficiency programs)	Investigating—open docket

State	Cost Recovery	Direct Lost Revenues Recovery	Performance Incentives	Decoupling
Ohio	Yes—Electric rate rider	No	NA—Electric (The Ohio Department of Development administers the electric energy efficiency programs.)	No—Electric Issue is being examined for natural gas utilities.
Oregon	Yes—Electric and natural gas SBC	No	N/A—Electric (The Energy Trust of Oregon administers the electric and natural gas energy efficiency programs.) No—Natural gas.	No—Electric. Yes—mechanisms in place for the two biggest natural gas utilities.
Rhode Island	Yes—Electric SBC	No	Yes	No
Texas	Yes	No	No	No
Utah	Yes—Electric rate or tariff rider/surcharge	No	No	No
Vermont	Yes—Electric SBC	No	Yes (non-utility)—Electric (A nonprofit, EVT, administers the programs. EVT can obtain an incentive for program performance.)	No (A proposal was submitted in one current rate case—settlement is pending.)
Washington	Yes—Electric rate or tariff rider/surcharge	No	No	Investigating—Electric
Wisconsin	Yes—Electric SBC, plus additional funding through rates is possible, if utilities request and PSCW approves.	No	Generally N/A—Electric (Currently the state of WI, Dept. of Administration administers the majority of the programs but utilities have the option to administer.) One exception, Alliant Energy is allowed to earn its rate-of-return on one C/I "shared savings" energy efficiency program.	No—Electric (A proposal was submitted in one current rate case.)

DISCUSSION

Soaring fuel prices, growing concerns about utility system reliability needs, and increasing awareness of future environmental risks have all reinvigorated interest in the use of energy efficiency as a serious utility system resource. With this renewed interest, there is an increasing recognition that in order to expect utilities to embrace the aggressive deployment of energy efficiency programs, something must be done to address the financial concerns utilities have regarding energy efficiency. As a result, a growing number of states are re-examining utility regulations and policies that govern utility planning, decision-making, and operations to ensure that such policies and regulations are supportive of energy efficiency objectives.

Utilities generally have three basic financial concerns regarding the funding and operation of energy efficiency programs.

(1) Assuring cost recovery for the direct costs of a program,
(2) Addressing the disincentives of "lost revenues" (or "lost sales") resulting from energy efficiency improvements that reduce customer energy use, and
(3) Providing an opportunity for shareholder earnings from good performance in providing programs and services for customer energy efficiency.

It is clear from our research, and from two decades of experience that program cost recovery is a minimum threshold for utility-sector customer energy efficiency programs to be funded and delivered. Utilities or other program administrators cannot be expected to operate serious programs without adequate funding and assurance that program costs can be recovered, whether via rates, tariff riders, or system benefits charges. Of these approaches, systems benefits charges are currently the most prevalent means to recover program costs, particularly in states with restructured electric utility industries. Non-restructured states more commonly use traditional regulatory case methods. A few states have a combination of the two approaches.

Beyond this basic cost recovery, however, a growing number of states have seen benefits from enacting mechanisms that either:

- provide some type of positive financial incentive for successful energy efficiency programs, or
- remove financial disincentives that may exist towards pursuit of such success.

Our survey of leading states shows that there are several ways to provide positive financial incentives for successful energy efficiency programs. Such mechanisms in many cases have been in place for several years—enough time to refine and gain experience in how the mechanism is applied. And perhaps more importantly, enough time to gain the attention and support of senior management within utility companies. If a utility's senior management is committed to supporting energy efficiency programs and sees the benefits they provide to customers *and* their company, energy efficiency programs are much more likely to be able to truly thrive, grow, and succeed. Without such support from upper management, programs may have a tenuous life at best with wide swings in funding and other resource commitments.

Providing positive direct financial incentives, such as are in place in Massachusetts, Rhode Island, and New Hampshire, has been found to be an effective mechanism because incentives are tied directly to clear performance goals for the energy efficiency programs. They also can be designed to include a number of specific objectives, tailored to specific programs or customer segments. We caution, however, that the performance incentive mechanisms should not be too complicated or difficult to understand and apply. If objectives and rewards are not reasonably simple, transparent, and well-defined, it may be difficult to achieve desired program goals, and there may be possible conflicts and confusion. The performance incentive mechanisms also need to be structured so that they indeed are rewarding program outcomes that are reasonably within the control or direct influence of the utility (administrator), not some extraneous factors or influences.

Removing disincentives for energy efficiency via decoupling of energy sales and revenues can also be very important for advancing energy efficiency by better aligning corporate financial interests with energy efficiency program objectives. California and Oregon are states at the forefront of these “modern” efforts at decoupling. In these states, enactment of decoupling has come as a key element of relatively comprehensive policy packages to support energy efficiency. Decoupling appears to be important to ensure that senior corporate managers truly embrace the expanded pursuit of energy savings through greater efficiency as provided by company programs and related policies.

While decoupling and shareholder incentives are gaining in popularity and application, there are thus far only limited examples where both of these mechanisms are in place. The use of shareholder incentives tied to program performance has been the predominant approach. (Although in many cases performance incentives have been seen as also a means of addressing utility management concerns regarding lost sales revenues—albeit indirectly—by at least providing some positive financial impact.) On the other hand, interest in adding a decoupling mechanism to the mix is growing rapidly, especially in the natural gas sector.

Decoupling is designed more specifically to address the problem of “lost revenues” by breaking the link between sales volume and profit. States that have enacted decoupling have done so with this intent; such a policy is viewed as helping to align company financial objectives with societal energy resource objectives. In all but one of the states that have adopted modern decoupling, there has been insufficient time to complete full cycles of rate cases to evaluate how well the mechanisms have worked. We did find one evaluation of such a mechanism—that applied to Northwest Natural Gas Company in Oregon—and the results there have been very positive. (We will discuss this example in Appendix C.)

Relationship of Regulatory Mechanisms to Level of Energy Efficiency Effort

Even with somewhat limited experience and application of these regulatory mechanisms, we do observe that those states that have implemented performance mechanisms and/or decoupling often are also states that rank high nationally in terms of their funding for energy efficiency programs. We cannot speculate on the degree of the causality of this relationship—program spending levels are generally the result of a number of policy decisions and factors. However, it is clear that states that are aggressively pursuing energy efficiency resources also are states that tend to have enacted regulatory policies such as performance incentives or decoupling. For example, ACEEE's most recent rankings of states according to electric energy efficiency program spending as a percentage of total utility revenues (York and Kushler 2006) show that five of the states in the top ten have such mechanisms in place. These states (and rankings and type of mechanism—either "PI" for performance incentives or "DC" for decoupling) are Vermont (1-PI), Massachusetts (2-PI), Rhode Island (4-PI), New Hampshire (5-PI) and California (10-DC). Other states highly ranked by spending as a percentage of utility revenues that also have shareholder mechanisms include Connecticut (PI) and Minnesota (PI). All of these states have been in the top tier of such rankings over many years, which indicates an on-going and long-term commitment to supporting energy efficiency programs.

We also note that some of the states highly ranked by their spending as a percentage of revenues have not implemented either performance incentives or decoupling for their electric utilities or other program providers; these states include Washington, Oregon, New Jersey, Iowa, Montana, and Wisconsin.[14] This suggests that there are other policy mechanisms and decisions that can drive higher levels of energy efficiency program spending. (One of these clearly is the decision to provide such programs through non-utility parties as part of public benefits policies.) Regardless of what other policies are in place, however, we believe that implementation of shareholder incentives and/or decoupling can be very effective as part of an overall energy efficiency policy package—that is, a set of complementary policies and decisions that work to achieve higher levels of customer energy efficiency—no matter how such programs are structured and provided.

CONCLUSION

In summary, we find that utilities have several important financial concerns regarding energy efficiency, and it is critical to take steps to address those concerns if one desires genuine utility cooperation in advancing customer energy efficiency. A minimum threshold requirement for achieving energy efficiency programs is to provide practical and reasonable cost-recovery for program costs. This can and has been successfully accomplished in a number of different ways in different states.

In order to move beyond minimal compliance behavior, however, it is very important to also provide some type of financial incentive tied to achieving energy efficiency objectives (e.g., savings achieved, cost-effectiveness, etc.). Again, this can and has been accomplished in a number of different ways in different states.

[14] One utility in Wisconsin, Alliant Energy, recently received approval to earn the same rate-of-return for its "Shared Savings" commercial/industrial program as the utility's rate-of-return for other capital investments, such as for new generation facilities. However, the overall statewide public benefits program and other utility programs do not have performance incentives in place for the program administrators or implementers.

Finally, in order to allow utility management to truly embrace broader energy efficiency objectives (i.e., beyond specific programs with specific rewards for certain accomplishments), it is important to do something to address the broader concern about reduced sales volume resulting in lower profits. “Decoupling” is the preferred mechanism for achieving that result. There has been less experience with that regulatory mechanism, although two states (Oregon and California) have had such policies in place long enough to observe some very impressive results in terms of utility cooperation and facilitation of aggressive energy efficiency implementation. Decoupling has also been recently adopted in a few additional states and is under active consideration in several more.

In conclusion, with the rapidly increasing interest in expanding energy efficiency as a utility system resource (for both economic and environmental reasons), we expect, and recommend, further adoption of regulatory mechanisms to address utility financial concerns regarding energy efficiency.

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APPENDIX A: STATE SUMMARIES OF PERFORMANCE INCENTIVES

Introduction and Background

Performance incentives. The use of performance incentives (also known as “utility incentives” or “shareholder incentives”) is a commonly used approach in states that have anything in place beyond program cost recovery. This has tended to be the most common because it is usually easier to accomplish than lost revenue recovery mechanisms. It also has often been generally regarded as helping to address both lost revenues and the desire by utilities to be able to “earn a profit” from their energy efficiency activities (these two concerns are sometimes lumped together and simply referred to as the utility's "financial concerns").

Again, there are many specific approaches that have been used to provide financial incentives that reward utilities for successfully reaching or exceeding program goals. These include:

- allowing utilities to earn a rate of return on energy efficiency investments equal to supply side and other capital investments,
- providing utilities an increased rate of return either on the energy efficiency investment specifically or overall utility investments,
- providing utilities with a specific financial reward for meeting certain targets, and
- providing utilities with an incentive equal to some proportion of the overall net benefits the programs produce (i.e., "shared savings").

Positive financial incentives have sometimes been balanced with negative financial penalties for poor performance or refusal to implement programs. In our review of states with current performance incentives in place, however, we found no specific penalties defined for non-performance. Rather, the “penalties” seem to take the form of the potential to not earn eligible incentive amounts.

Table A-1 below presents a summary of the states surveyed that have performance incentive mechanisms in place.

Table A-1. Summary Table of Performance Incentive Mechanisms

State	Performance Incentive Type	Basis for Performance Metric?	Amount of Compensation Available (Max Value as % of Program Expenses)	Process/Ease of Application
AZ	Specific financial reward	Share of net benefits	10% of program budget	Funding cycle not completed yet; part of general rate cases.
CT	Specific financial reward	Savings goals and other program goals	Up to 8% of program costs before taxes	Fairly straight-forward. Good track record.
MA	Specific financial reward	Multi-factor performance targets: savings, value, and performance	Up to 9% of program costs before taxes (5.5% after taxes)	Fairly straight-forward. Good track record.
MN	Proportion of overall net benefits	Energy savings goals	Up to 30% of program costs for reaching 150% of program targets	A little more complex than most. Good track record.
NV	Increased rate of return on equity	Program spending goals	Extra 5% return on equity for EE investments	Somewhat complex. New, no record yet.
NH	Specific financial reward	Savings and cost-effectiveness goals	8–12% of program budgets	Fairly straight-forward. Good track record.
RI	Specific financial reward	Savings and cost-effectiveness goals	5.5% of program costs	Fairly straight-forward. Good track record.
VT	Non-utility: specific financial reward	Multi-factor performance targets: program results, market effects, and activity milestones	About 2% of total contract	Assessed and awarded over length of contract period—3 years.
WI	Allowed to earn same rate of return as for supply-side investments	Determined in rate cases; not specified	Not available	Part of much larger process—general rate cases.

Arizona

Overall Energy Efficiency Program Approach and Structure

From the late '90s into the early 2000s, Arizona's investor-owned utilities have operated fairly modest DSM programs and services; total funding for programs has ranged from $4–9 million per year for the period 1999–2005. A settlement agreement reached in an Arizona Public Service Company rate case will greatly increase funding and corresponding program activity. APS is to spend at least $16 million annually for the period 2005–2007.

The investor-owned utility companies administer the energy efficiency programs, along with low-income and renewable energy programs funded through a systems benefits charge. For all types of programs, the utility companies either implement the programs themselves or hire contractors to implement the programs. The Arizona Corporation Commission (ACC) approves the companies' proposed programs and budgets. ACC approval is required for the companies to recover costs.

Funding for the energy efficiency, renewable energy, and low-income programs, referred to as the system benefits charge, is included in the affected utilities' or distribution utility companies' base rates and varies by company. The ACC reviews the programs and funding levels periodically. Changes in utility company SBC funding levels must be requested through the ACC in the company's rate case. The ACC also has established a DSM collaborative that is to advise APS on its program design, implementation, and evaluation.

Performance Incentives

Arizona Public Service is moving ahead to implement a set of programs with a total annual budget of about $16 million. There is a performance incentive included that could amount to 10% of the total program budget. This shareholder incentive was established in ACC's Decision Number 67744, issued in April 2005. The ACC describes the structure of the shareholder—or performance—incentive in the following excerpt from this decision:

> APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with paragraph 41. Such performance incentive will be capped at 10% of the total amount of DSM spending, inclusive of the program incentive, provided for in the Agreement (e.g., $1.6 million out of the $16 million average annual spending referenced in paragraphs 40 and 44 or $4.8 million over the initial three-year period). Any such performance incentive collected by APS during a test year will be considered as a credit against APS' test year base revenue requirement. The specific performance incentive will be set forth in and approved as part of the Final Plan referenced in paragraph 48.

Decoupling and Lost Revenue Recovery

Nothing is in place, proposed, or being investigated.

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Connecticut

Overall Energy Efficiency Program Approach and Structure

Connecticut's energy efficiency programs are supported by a monthly system benefits charge (approximately 3 mills/kWh for "Conservation and Load Management"—C&LM) on customers' electric bills. A plan for the C&LM programs is drafted by the distribution utilities, reviewed by the Energy Conservation Management Board and its consultants, and ultimately approved by the Department of Public Utility Control (DPUC).

The Energy Conservation Management Board, appointed by the DPUC, administers the C&LM Fund. The C&LM programs are administered by the distribution utilities and the Board provides oversight. The Board helps the distribution companies prepare a comprehensive energy efficiency/market transformation plan that must be approved by the DPUC. It is required that all programs included in the plan pass a benefit-cost test. Each electric distribution company keeps a separate Conservation and Load Management Fund. Disbursements from the fund, for projects included in a plan, must be approved by the DPUC. The Board is required to submit annual reports to the legislature. These reports are to include expenditures, fund balances, and benefit-cost analyses for the previous year's programs. Administrative costs are not to exceed 5 percent of the total revenue collected.

Each year the Energy Conservation Management Board meets to review and approve distribution utility energy efficiency program plans. These are formal, uncontested hearings. Board consultants work with the utilities in developing their plans. The utilities set goals (savings and other program metrics) for program results in conjunction with these hearings.

Performance Incentives

As part of the annual hearing, the Board also looks back at the past year's results relative to the established goals and determines a performance incentive for the distribution utilities, which can be from 1-8% of the program costs before taxes (referred to as a "management fee") for achieving or exceeding established goals. The minimum threshold is 70% of goals and would earn the minimum (1%) incentive. For reaching 100% of goals the incentive would be 5%, and for reaching 130% of goals it would be 8%. Program costs are recovered through rates.

Anticipated incentives are built into the annual budgets. Over the course of several dockets, the DPUC has affirmed the value of the incentive, and that the expenditures used to calculate the incentive may include administrative and overhead costs, but not Board costs and the incentive costs. Due to problems in southwestern Connecticut, in 2002 the DPUC agreed to utility incentives for MW savings from load response programs (LRP). In Docket 01-01-14, September 19, 2001, the DPUC agreed on a reasonable rate of return when DUs market and sell their C&LM programs.

Connecticut has had some type of utility performance incentives in place for DSM since 1988. The exact mechanism has changed over time. The incentives do seem to motivate the utilities to meet or exceed their goals, according to the stakeholder surveyed.

Decoupling and Lost Revenue Recovery

Connecticut first considered decoupling in the 1990s. In 1991 the Legislature authorized the Department of Public Utility Control to take several steps to decouple utility sales and revenues, although no specific decoupling mechanism was enacted.

More recently Connecticut investigated decoupling again. In a June 2005 Special Session, the General Assembly enacted PA 05-01, which includes several provisions to "promote conservation and distributed generation." Section 21 of this act requires the DPUC to investigate how best to decouple earnings of gas and electric utilities from their sales in order to promote the state's energy policy. The act required DPUC to report its finding and recommendations to the Legislature's Energy & Technology Committee by January 1, 2006.

The DPUC accordingly investigated decoupling under CT DPUC Docket 05-05-09. In its decision, the DPUC rejected enacting any changes to existing rate-making approaches for electric and natural gas utilities. Two natural gas local distribution companies (LDCs) already are subject to a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a "conservation adjustment mechanism") and a third is considering applying to enact this.

In its decision on decoupling, the DPUC commented on its existing performance incentive mechanisms:

> The electric DCs [distribution companies] in Connecticut currently spend ratepayer funds of approximately $60 million annually on conservation. The electric DCs are allowed an incentive payment on the amount of C&LM funds they administer and recent legislation provides additional incentives and a lost revenue adjustment for new C&LM load response and DG initiatives undertaken to reduce federally mandated congestion costs. The electric DCs

> are only allowed recovery of lost revenues if their earnings are below their allowed rate of return for six months. This change significantly improves the C&LM adjustment clause.
>
> The Department believes that recent experience has shown that the electric DCs are performing well and that incentives available to the companies and their customers provide good incentives to promote conservation and load management.

There traditionally has been no mechanism for lost revenue recovery. The performance incentive in place has addressed some of this concern by rewarding utilities for achieving savings targets. However, as noted above, due to severe congestion on the transmission and distribution grid in certain regions in Connecticut, the DPUC has introduced a type of lost-revenue recovery mechanism for "new CL&M load response and DG [distributed generation] initiatives" to address this specific need.

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Massachusetts

Overall Energy Efficiency Program Approach and Structure

Massachusetts has a restructured utility industry with competitive generation and retail markets. The distribution companies remain regulated and are required to offer energy efficiency and other demand-side management programs. The distribution utilities administer their own energy efficiency programs with collaborative input and oversight from the state Division of Energy Resources (DOER) and the Department of Telecommunications and Energy (DTE).

The energy efficiency and low-income programs are funded by a monthly charge (system benefits charge) on customers' electric bills (approximately 2.5 mills/kWh). The distribution utilities collect the funds. The money collected via the systems benefits charge goes into a trust fund. Each company (regulated distribution utility) estimates how much money it will collect each year. This determines how much they have to spend on energy efficiency programs that year. If the company over- or underestimates the budget, the difference is made up the following year. Based on the budget, each company submits an annual energy efficiency program proposal. The companies work with a group of stakeholders (a "collaborative") in developing their plans. The Division of Energy Resources is responsible for assisting with the design of the plan, and allocation of monies to the various sectors. The plan is then reviewed by the state's utility regulatory authority, the DTE, for cost-effectiveness. The utility companies manage and implement the actual programs.

Performance Incentives

A shareholder incentive is in place for utility energy efficiency programs that provides an opportunity for companies to earn about 5% of program costs as an incentive for meeting established program goals. After the programs have been implemented, the utilities measure the program savings. The incentive is based on the results of this measurement and evaluation phase. The incentive is based on a combination of elements including energy savings, benefit-cost, and market transformation results. The order that approved the incentive is DTE Order 98-100.

The incentive is based on a program-by-program basis so it is not an all-or-nothing mechanism. In Docket DTE 98-100, the DTE determined that all costs associated with program implementation would be included in the calculation of the incentive, including marketing, administration, and evaluation. An energy efficiency program collaborative and the utilities negotiated a revised shareholder incentive proposal that was presented to the DTE in 2003. The distribution utilities agreed to more stringent goals (including energy savings, acquisition efficiency, and market incentives) and accountability with the Collaborative in return for a more reasonable shareholder incentive.

Decoupling and Lost Revenue Recovery

No decoupling mechanism is in place; none is being investigated or proposed. No lost revenue recovery mechanism is in place or proposed. There was a lost revenue mechanism in place in the early 1990s, but this was dropped in conjunction with the industry restructuring. The performance incentive mechanism in place is viewed by many, including commission staff interviewed, as addressing structural disincentives toward energy efficiency. This shareholder incentive mechanism in place now also is a lot easier to manage than were mechanisms addressing lost revenues, according to commission staff surveyed.

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Minnesota

Overall Energy Efficiency Program Approach and Structure

Minnesota statutes require a specified spending by regulated natural gas and electric utilities on energy efficiency programs (according to filed and approved “Conservation Improvement

Programs" or "CIPs"). Xcel Energy must spend 2% of gross operating revenues (GOR) on programs; all other electric utilities must spend 1.5% of GOR. Natural gas utilities must spend 0.5% of GOR.

Cost recovery for energy efficiency programs is through rate cases, which include consideration of program costs and incentives. Rate cases yield a "conservation cost recovery charge" (CCRC), which is part of base rates. This charge is derived by taking the approved CIP budgets and dividing this by sales estimates. Minnesota also uses a "conservation cost adjustment," which is used for annual true-up and tracking of program expenses. Utilities establish a "tracker account" to show how much of the CIP program budgets are recovered through rates. There is a provision for utilities to receive or pay interest on this amount, depending on how it tracks approved CIP budget (for under- or over-recovery). Program plans are made and approved on a 2-year cycle. Approved CIP expenses are trued up annually.

Performance Incentives

In 1999 the Minnesota Public Utility Commission agreed to a performance-based incentive for utility energy efficiency programs. Utilities are rewarded with a specific percentage of net benefits (as measured by the utility cost-effectiveness test) created by their actual investments in energy conservation. The percentage of net benefits awarded increases as the percentage of energy-savings goal achieved increases. The incentive is calibrated such that at 150% of the energy-savings goal, the utility would receive about 30% of the utility's conservation expenditure budget as required by statute. Under the incentive design, utilities are also rewarded for delivering their programs more cost-effectively because more net benefits are created when actual costs are lowered. Ratepayers fund the incentive during the following year when the PUC adjusts rates. Recently these charges have been on the order of 1.45%.

This incentive seems to be working well to encourage spending above statutory requirements (which is occurring). Utilities informally have indicated that their management is more supportive of energy efficiency investments because: (1) recovery of the conservation investment is guaranteed including a carrying charge on these investments, as well as an annual automatic adjustment to recover these investments, and (2) the performance incentive makes additional investments more attractive (beyond simply fulfilling statutory requirements for spending levels).

Decoupling and Lost Revenue Recovery

Minnesota had a "lost-margin recovery mechanism" in place in the 1990s, but because this was cumulative, utilities were recovering financial incentive amounts greater than their actual conservation expenditures (the lost-margin incentives totaled about $40 million in 1998). This had the effect of doubling the cost of energy conservation to ratepayers. In 1998 the Department of Commerce recommended that this mechanism be changed. This change led to the development in 1999 of a "Shared-Savings Financial Incentive," described above.

There is no decoupling mechanism in place or proposed. However, the PUC may open a docket to explore the issue because there is a lot of recent interest in decoupling mechanisms.

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Nevada

Overall Energy Efficiency Program Approach and Structure

Nevada returned to a traditional regulated utility structure after it restructured its industry in the late 1990s. Nevada's vertically integrated, investor-owned utilities are required to perform integrated resource planning and related demand-side management programs. The utility companies administer the energy efficiency programs with oversight by the Public Utility Commission of Nevada (PUCN). The utility companies hire contractors to implement the programs. The companies propose a budget and program plan to the PUCN as part of integrated resource planning requirements.

The utility companies must have their program plans and budgets approved by the PUCN prior to implementation. The utility companies collect an energy efficiency system benefits charge through customers' electric rates that funds the programs. The companies file general rate cases every two years, at which time they request full recovery of their program costs.

Performance Incentives

The revised regulations for IRP and DSM (Docket No. 02-5030) adopted in May 2004 include a provision that allows utilities to earn as much as an extra 5% return-on-equity (ROE) for applicable, approved DSM costs (base ROE is 10.25%—meaning that utilities could earn up to 15.25% ROE). This fraction is to be determined in individual rate cases; the provision calls for applying the utility's debt-to-equity ratio to the fraction of capitalized (rate base) DSM costs, and then applying the extra 5% ROE to that amount. This incentive amount for DSM is automatic as long as utilities follow approved plans and budgets. However, it is possible that the Public Utilities Commission could reduce this earnings amount as a result of a hindsight prudence review.

Decoupling and Lost Revenue Recovery

No lost revenue recovery mechanism is in place or proposed. Some parties have expressed interest in decoupling, but there have been no proposals or investigations.

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New Hampshire

Overall Energy Efficiency Program Approach and Structure

New Hampshire restructured its electric utility markets and has maintained support for its utility energy efficiency programs. In Order No. 23,574, issued November 2000, the Commission emphasized its commitment to energy efficiency programs that complement the new energy markets and do not hinder their development. The Commission requested that the utilities work together to design a set of "core" programs that are consistent in program offering and design and that meet the Legislature's directive to target cost-effective opportunities that may otherwise be lost due to market barriers.

On May 31, 2002, the New Hampshire Public Utilities Commission entered Order No. 23,982 in Docket No. DE 01-057, approving the implementation of proposed "Core" energy efficiency programs to be provided by the state's electric utilities through the end of 2003. This Order established the basis for the *NHsaves* statewide energy efficiency program. Participating utilities in NHsaves are Connecticut Valley Electric Company, Granite State Electric Company, New Hampshire Electric Cooperative, Unitil/Concord Electric Company, Unitil/Exeter & Hampton Electric Company, and Public Service of New Hampshire.

The PUC reviews and authorizes the utilities' joint program plans and budgets annually. The utilities collaborate to offer joint, statewide programs in order to gain the benefits from uniform planning, delivery, and evaluation. A stated objective of the utilities is to provide services that "will not depend on which community the customer or member resides or does business." Within the umbrella of a statewide program, however, another goal is that each individual utility would incorporate flexibility in its implementation strategies and in the manner in which it delivers program services. From the customer's perspective, the program is to look virtually the same in all service territories. NHsaves uses common marketing and information materials (such as its Web site).

Funding for NHSaves is provided by a systems benefits charge applied on customer rates—3.0 mills/kWh total (1.8 mills/kWh for energy efficiency and 1.2 mills/kWh for renewables and low-income programs).

Performance Incentives

Utilities can earn performance incentives for 8–12% of total program budgets for meeting established cost-effectiveness and energy savings goals. In Order 23,574, November 2000, the Commission accepted the recommendation of the Working Group to provide shareholder incentives to utilities. The shareholder incentive approach is based on the performance of the programs measured in terms of their actual cost-effectiveness and energy savings relative to the projected cost-effectiveness and energy savings, respectively. Separate target incentives are set for residential and commercial/industrial sectors—each set at 8% of the total program and evaluations budgets for each sector. Superior performance could be rewarded by up to 12% of the planned sector budgets. Issues with lost revenues are to be dealt with on a utility-specific basis by the Commission.

Decoupling and Lost Revenue Recovery

No lost revenue mechanism is in place or proposed. No decoupling mechanism is in place or proposed.

References

New Hampshire Public Utilities Commission. Orders:
- Order No. 23,982 in Docket No. DE 01-057. Year 2002.
- Order No. 23,574. Year 2000.

Rhode Island

Overall Energy Efficiency Program Approach and Structure

Rhode Island is a restructured state with retail competition and competitive generation markets. Regulated distribution utilities' customers pay a 2 mills/kWh non-bypassable public benefits fee that supports energy efficiency programs offered by the distribution utilities. The major investor-owned utility operating in the state, Narragansett Electric, is a National Grid Company and offers a slate of programs that parallel National Grid's offerings in Massachusetts.

Hearings are held once a year for each company to review program plans. A collaborative of stakeholders reviews and makes recommendations to the Rhode Island Public Utilities Commission on the programs. Program costs are trued up in May.

Performance Incentives

Shareholder incentives are in place, subject to annual PUC review and approval. For 2005 (Docket 3635, Order 18152), the PUC established a shareholder incentive for Narragansett Electric based on meeting specified goals. The mechanism includes two components: (1) five performance-based metrics for specific program achievements, and (2) kWh savings targets by sector. The program performance metrics are established for each program, such as achieving a certain market share or penetration for the targeted energy-efficient technology (for example, market share of ENERGY STAR® new homes). The target incentive rate for the kWh savings goal is 4.4% of the eligible spending budget. The threshold performance level for energy savings by sector is 60% of the savings goal. The Company has the ability to earn an additional incentive on savings up to 125% of target savings.

This incentive is “very effective” according to the staff person we surveyed. The utilities meet most of their goals and have excellent programs in place.

Decoupling and Lost Revenue Recovery

No mechanism is in place or proposed for lost revenues or decoupling. The performance incentives in place are seen as helping address these issues.

Reference

Rhode Island Public Utilities Commission. 2005. Order 18152, Docket 3635.

Vermont

Overall Energy Efficiency Program Approach and Structure

In June 1999, the Governor signed S. 137 clarifying the Vermont Public Service Board (PSB) authority to approve the creation of an Energy Efficiency Utility (EEU), a state-sponsored nonprofit organization to offer statewide efficiency services to residential, commercial, dairy, and industrial customers. These programs replaced the energy efficiency programs that the utilities were offering. On September 30, 1999, in Docket No. 5980, the PSB approved the EEU after the state and the state’s 22 electric utilities reached consensus in a Memorandum of Understanding.

In the September 30, 1999, Docket No. 5980, Memorandum of Understanding, the parties reached agreement that a fiscal agent, a contract administrator, and an advisory committee would be selected by the PSB to help oversee the EEU. In December 1999, a Burlington-based consortium, Vermont Energy Investment Corporation (VEIC), won the competitive bid for the role as the EEU and is responsible for the statewide implementation of Vermont’s energy efficiency programs either directly or through subcontracts. A fiscal agent receives monies collected by the electric distribution companies and disburses the funding to the EEU. The contract administrator assists the PSB in managing the details of the contract between the PSB and the EEU. Members of the advisory committee representing the distribution utilities, consumers, and other stakeholders offer input on program design, re-allocation of funds within programs, and any other issues that will assist the PSB.

The statewide program, “Efficiency Vermont,” has offered programs since 2000.

Performance Incentives

While not a utility-administered program, Vermont’s “energy efficiency utility” is eligible to receive a performance incentive for meeting or exceeding specific goals established in VEIC’s contract with the Public Service Board. For the 2000–2002 contract, VEIC could earn up to $795,000 over the three years of the contract. The contractor must submit annual claims for its performance awards according to the schedule, documentation, and verification processes established in the contract.

According to the contract:

> The Contractor’s performance incentive mechanism is designed to reward superior performance by the Contractor in the overall administration and delivery of “Core Programs” and includes three major categories or types of incentives, with specific indicators that will govern the award of the incentives.

The three major categories or types of incentives are:

- Program results incentives: reward the contractor for accomplishing targets for direct market impacts, including electricity savings, lifetime resource benefits, cost savings, market penetration of energy-efficient technologies, and leveraging of ratepayer dollars.
- Market effects incentives: reward the contractor for “demonstrated significant market transformation” that has been achieved through the programs.
- Activity milestone incentives: reward the contractor for achieving specified milestones that involve “exemplary performance for rapid start-up and/or infrastructure development.” This incentive was particularly designed for the initial phases of program design, development, and implementation.

Weighting of these factors was as follows in the initial contract:

- Program results incentives (72% total):
    - Annual electricity savings: 25%
    - Electricity savings for projects under development: 5%
    - Total resource benefits: 15%
    - Individual and cross-program indicators: 32%
- Market effects incentives: 3% (note: this was the start-up period of the statewide program)
- Activity milestones incentives: 20%

The maximum amount of this performance incentive was about 2% of the total contract award for this period.

Subsequent contracts between the PSB and VEIC have focused more on program results and less on activity milestones since such milestones really addressed more of the "start-up" concerns with a new program. Program incentive levels also have been ratcheted up with the intent that incentives should be earned for meeting "stretch goals" indicative of a growing and maturing program. The idea is that program administrators should not necessarily earn incentives for average performance—or at least such incentives at that level should be less. Incentives should be structured to reward superior performance.

Decoupling and Lost Revenue Recovery

There is no mechanism in place for decoupling or lost revenue recovery. Green Mountain Power has recently proposed a decoupling mechanism as part of a recent rate case; a review and settlement agreement on this proposal were pending as this report went to publication (Docket Numbers 7175 and 7176 before the Public Service Board, "Green Mountain Power Rate Increase Investigation and Alternative Regulation Plan").

References

Hamilton, Blair and Michael Dworkin. 2004. "Four Years Experience of the Nation's First Energy Efficiency Utility: Balancing Resource Acquisition and Market Transformation Under a Performance Contract." In *Proceedings of the 2004 ACEEE Summer Study on Energy Efficiency in Buildings,* 5.129–5.140. Washington, D.C.: American Council for an Energy-Efficient Economy.

Wisconsin

Overall Energy Efficiency Program Approach and Structure

Wisconsin has a state-administered public benefits energy program, which is funded through a specific non-bypassable charge on customer bills. There is no market restructuring/deregulation, however, and vertically integrated, investor-owned utilities are still regulated providers—and still offer energy efficiency programs to varying degrees. One utility, Alliant Energy (Wisconsin Power & Light), has continued to offer its commercial/industrial customers a "Shared Savings Program," for which the Company is allowed to earn its rate-of-return on these energy efficiency costs. Wisconsin Public Service Corporation and We Energies (Wisconsin Electric) both have commission-established goals for DSM as a result of new power plant construction cases (energy efficiency savings targets were established in approving new power plant construction).

The State of Wisconsin, Department of Administration, has the overall responsibility for administration of the statewide program, "Focus on Energy." The Division of Energy within DOA (the state energy office) oversees the program—providing overall direction and managing budgets as some of its primary functions. More specific program administration—

design, management, and implementation of individual programs—is performed by four4 separate primary contractors, one each for the major program areas: (1) residential energy efficiency, (2) non-residential energy efficiency (including business, government, institutional, industry, and agriculture), (3) renewable energy, and (4) environmental research.

The primary contractors, in turn, work with subcontractors and program partners to deliver specific program services and perform program tasks. In addition to these four primary contractors, DOA also has separate contractors for other key program functions, including marketing and evaluation.

Cost recovery for the utility programs is handled via individual rate cases. There is a conservation escrow account, which is used for approved utility DSM program plans. Program costs are recovered through rates—money goes into an escrow account—and then is trued up in the next rate case. If utilities spend more than the approved budget, they generally receive cost recovery almost automatically through the true up. If the amount of actual spending is higher than the amount collected in escrow, the utilities may amortize cost recovery. If actual spending is less than the escrow amount, the PSC would true it up through a reduction in escrow for the next rate period.

Performance Incentives

A decision in a recent rate case (Docket 6680-UR-114) of Wisconsin Power & Light (Alliant Energy) allows the company to earn the same rate-of-return on its investments in energy efficiency made through its "Shared Savings" program for C/I customers as it earns on other capital investments (e.g., power plant construction.).

Utilities can propose incentives as part of their rate cases, but there have been no such proposals from other utilities recently.

Wisconsin did have performance incentives in place in the early to mid-'90s, but dropped them as the state began investigating restructuring and deregulation. The utilities at that time thought such costs made their rates too high in anticipation of competing in regional and national markets.

Decoupling and Lost Revenue Recovery

There is no mechanism for lost revenue recovery, but Wisconsin uses a forward-looking test year. This minimizes lost revenues since savings projections are included in the base forecast used to determine revenue requirement. There also is no decoupling mechanism in place. The Citizens Utilities Board of Wisconsin proposed a decoupling mechanism in a recent rate case (66-80-UR-114), but such a mechanism was not implemented.

References

Wisconsin Public Service Commission. 2005. Order in Docket 6680-UR-114. Alliant Energy Rate Case.

APPENDIX B: STATE SUMMARIES OF DECOUPLING MECHANISMS

States with Decoupling Mechanisms in Place or Proposed

Over the past two decades, a number of states across the U.S. have experimented with some form of utility revenue decoupling. In this section we examine both historical and recent experiences with decoupling, including a series of state-by-state summaries of these experiences.

The renewed interest in decoupling is occurring in parallel with renewed interest in the "resource" aspect of energy efficiency. This renewed interest seems to stem from a number of factors, including rising "supply-side" costs, growing demand for energy resources, and heightened environmental concerns. Support for decoupling comes from a broad spectrum of industry stakeholders—environmental groups, consumer advocates, utilities, and trade associations. For an example of the latter, the American Gas Association is strongly in favor of decoupling—not necessarily just for its benefits related to energy efficiency investments, but probably more to provide more secure and stable revenue streams in an industry increasingly concerned about fixed-cost recovery.[15]

"Decoupling" has re-emerged as a mechanism of interest to address lost revenues and to remove the disincentive for utilities to pursue energy efficiency programs. There are a growing number of jurisdictions that have enacted or are actively considering enacting decoupling. Below we provide brief profiles and summaries of leading states that have enacted or have seriously investigated and considered implementation of decoupling.

California

Overall Energy Efficiency Program Approach and Structure

California's investor-owned utilities administer energy efficiency programs with CPUC oversight. These programs are funded both by a public goods charge and via rates as a result of recent CPUC decisions to aggressively pursue acquisition of energy efficiency resources as part of the state's energy plan. The CPUC approves the utilities' plans for efficiency programs and oversees the program planning, market assessment, and program evaluation of the efficiency programs. In addition to the utility programs, there also are programs administered and implemented by "third-party providers" as a way to encourage innovation and ensure coverage of markets that utility programs may be missing.

California's structure and funding for energy efficiency programs are undergoing major changes as a result of recent legislative and regulatory decisions. The state has a "public goods" wires charge in place that had become the primary funding mechanism for utility energy (and some non-utility) energy efficiency programs. This charge is assessed as a separate line item on customers' monthly electric bills and as a small charge per therm on

[15] Many gas utilities are facing stagnant or declining sales levels in response to high natural gas prices. This has led to a growing interest in decoupling mechanisms.

natural gas bills. Utilities also have been authorized to raise additional program dollars in the utility procurement process as determined in general rate cases.

In September 2005, the CPUC embraced an aggressive resource procurement plan for energy efficiency, on top of its base of public goods charge program funding. Between the two sources, the regulated utilities will spend a total of $2 billion over the 3-year period of 2006–2008. Cost recovery for the resource procurement portion of the energy efficiency will presumably occur through regulatory casework.

Performance Incentives

The utilities used to be able attain shareholder incentives based on the success of their programs. Performance incentives, however, have been eliminated. In Decision 02-03-056 delivered in March 21, 2002, the California Public Utilities Commission stated:

> In the past, the Commission has offered shareholder incentives to large IOUs for successful program delivery, in lieu of a profit margin. The Commission will no longer make a special provision for shareholder earnings. Both utility and non-utility entities are free to propose program budgets they feel are necessary for their organizations to complete the program delivery successfully.

While there are no performance incentives presently in place, the CPUC has kept the door open for enactment of such mechanisms in individual utility rate cases. The CPUC is currently undergoing extensive efforts to establish a common performance basis for energy efficiency programs that will capture cost-effective energy savings that defer more costly supply-side investments and costs. Once these foundations and frameworks are established, the CPUC will work on establishing performance incentives for energy efficiency programs.

Decoupling and Lost Revenue Recovery

California was one of the first states to enact decoupling mechanisms for its regulated electric utilities. In 1982 the CPUC adopted an "electric rate adjustment mechanism" (ERAM) to achieve two key objectives: (1) decouple utility revenues from sales; and (2) remove disincentives for utility investment in energy efficiency and conservation. This mechanism was implemented in conjunction with the state's integrated resource planning requirements. ERAM required utilities to track the difference between actual and forecasted base rate revenues. Overcollections would then be refunded to ratepayers and undercollections would be recovered by subsequent rate adjustments. ERAM allowed the utilities to recover their revenue requirements independent of actual energy sales.

California's experience with ERAM was generally positive. It was largely successful in reducing rate increase risk to customers and revenue recovery risks to the utilities. Despite that positive track record, however, other industry developments led to the elimination of ERAM in the mid-1990s. Specifically in conjunction with restructuring its electric utility industry, the CPUC ruled that ERAM would no longer be appropriate. In Order D.96-12-077 the CPUC concluded:

> Introduction of competition for generation will render ineffective the CPUC's past approach of supporting demand-side management by using ERAM to counter the utility's economic incentive to increase sales.

As it turned out, California's restructured electricity markets failed to function effectively, leading to the infamous "crisis" of 2001. As a result, California enacted another set of sweeping changes to its electricity markets—re-introducing regulatory control over utilities and placing the responsibility for "resource portfolio management" back with the utilities. The legislation that was enacted in 2001, AB29X, also included regulatory provisions for ratemaking. One of these specifically addressed decoupling requirements:

> The Commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations. (Public Utilities Code Section 739.10).

This rather tersely worded statutory language essentially requires revenue decoupling. This statute rules out any ratemaking approach that ties earnings to sales fluctuations and also provides regulated utilities with assurance of cost recovery for authorized revenue requirements. From 2002–2005, California's investor-owned utilities developed and implemented decoupling mechanisms as required by this statute. Each utility's mechanism arose out of general rate cases before the CPUC. While specific details of the mechanisms vary, they share a common approach, which is to use balancing accounts for annual true-ups. This protects utilities from fluctuations in revenues stemming from fluctuations in sales for any of many possible reasons (energy efficiency and conservation are just two of these—weather and economic activity are other prominent reasons). Through individual rate cases, the CPUC determines initial revenue requirements and then takes one of two specific approaches to adjusting revenue requirements between rate cases:

- Using attrition mechanisms that escalate revenue requirements by inflation minus a productivity offset every year—and adding a factor to account for customer growth; or
- Using an inflation adjustment (consumer price index) to escalate the revenue requirement each year with boundaries set for a minimum and maximum allowable escalation.

The changes in rate-making approaches for California's utilities have occurred during a period of significant changes overall with California's approach to energy efficiency. In September 2005, the CPUC embraced an aggressive resource procurement plan for energy efficiency, on top of its base of public goods charge program funding. The CPUC adopted an "Energy Action Plan" (CPUC 2005) that places energy efficiency as the first resource in utility loading order—meaning that the first dollars spent by California's utilities are to be on cost-effective energy efficiency. This policy in turn is translating to unprecedented levels of investment in new energy efficiency resource in California. Over the next three years, 2006–

2008, California plans to invest a total of $2 billion in energy efficiency through programs offered by utilities and other organizations. These investments are to achieve aggressive targets for energy efficiency savings impacts—by the year 2013, reducing peak demand by nearly 5,000 MW and reducing energy use by over 23,000 GWh and 400 million therms.

California's decoupling initiatives are thus one element of a much larger energy policy—a policy that requires utilities to commit large amounts of resources to fund and implement energy efficiency programs. We found no efforts to date that attempt to evaluate the impacts of just the decoupling mechanisms on the utilities' investment and related actions toward energy efficiency programs. Given these tremendous additional changes with CPUC targets and approved budgets for energy efficiency programs, we believe it will be difficult to isolate the specific policy impacts of decoupling. However, we also observe that establishing such mechanisms is a valuable complement to achieve the overall policy objective. It's part of a "complete package" to align utility financial interests with public policy interests towards greater levels of energy efficiency.

References

[CPUC] California Public Utilities Commission. 2005. *Energy Action Plan.* Sacramento, Calif.: Public Utilities Commission of the State of California.

[CPUC] California Public Utilities Commission. Various years. Decisions:

- Decision 04-07-022. *Opinion on Base Rate Revenue Requirement and Other Phase 1 Issues. Application of Southern California Edison Company for Authority to, Among Other Things, Increase Its Authorized Revenues for Electric Service in 2003, and to Reflect That Increase in Rates.* July 16, 2004.
- Decision 04-05-055. *Opinion: Phase 1 Issues. Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003.* May 27, 2004.
- Decision 05-03-023. *Decision on Southern California Gas Company and San Diego Gas & Electric Company's Phase 2 Post-Test Year 2004 Ratemaking, Earnings Sharing, Incentive Proposals, and 2004 Incentive Proposals.* March 17, 2005.
- D.96-12-077 [Copy not available; cited by Prusnek 2005]

Prusnek, B. 2005."Promoting Energy Efficiency in California." Presentation to the State EE/RE Technical Forum. May 18. U.S. Environmental Protection Agency, State and Local Clean Energy Programs.

Southern California Edison Company, San Diego Gas and Electric Company, Southern California Gas Company, and Pacific Gas and Electric Company. 2006. "Decoupling Mechanisms—Energy Efficiency Policy Impacts and Regulatory Implementation." In *Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings.* Washington, D.C.: American Council for an Energy-Efficient Economy.

Idaho

Overall Energy Efficiency Program Approach and Structure

The state's vertically integrated, regulated utilities administer energy efficiency programs. Cost recovery is by individual rate cases and rate design. Generally the approach taken by the Idaho Public Utilities Commission is using rate design to reduce energy rates (variable costs) and use more fixed costs to recover revenue requirement.

Rate riders (surcharges) are also used. Both Pacificorp and Idaho Power have 1.5% surcharges collected as an adder on customer bills to fund energy efficiency programs. The final order for a Pacificorp rate case has not been issued yet, which may change this surcharge slightly.

Performance Incentives

None in place. PUC staff are interested in moving toward some type of performance-based ratemaking, but nothing is proposed or in-process.

Decoupling and Lost Revenue Recovery

There is no mechanism for lost revenue recovery.

Decoupling is being actively proposed and investigated. In May 2004, in a general rate case for Idaho Power Company (Case No. IPC-E-03-13, Order No. 29505), the Idaho Public Utilities Commission (IPUC) determined that a separate proceeding was called for to "assess financial disincentives inherent in Company-sponsored conservation programs." The Commission directed the parties to propose a workshop schedule and initiate a proceeding. On June 18, 2004, the parties formally requested that a proceeding be initiated, and on August 10, 2004 the IPUC established Case No. IPC-E-04-15 for an "investigation of financial disincentives to investment in energy efficiency" by Idaho Power Company.

A series of workshops were held and a final report filed by the parties on February 14, 2005 ("Final Report on Workshop Proceedings"). The parties all agreed that "material financial disincentives to the implementation of DSM programs do exist" (p. 6), but not all participants agreed that restoration of lost fixed-cost revenues alone would directly result in additional or more effective investment in DSM programs by Idaho Power. However, the parties did all agree on a set of principles, or "criteria," to use to evaluate possible approaches to address the lost fixed-cost revenues problem. Those criteria are:

1. Stakeholders are better off than they would be without the mechanism.
2. Minimizes cross subsidies across customer classes.
3. Removes financial disincentives.
4. Optimizes the acquisition of all cost-effective DSM.
5. Promotes rate stability.
6. Simple mechanism.

7. Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation.
8. Monitors short and long-term effects to customers and company.
9. Avoids perverse incentives.
10. Closes link between mechanism and desired DSM outcomes. (p. 7)

The parties also agreed on two recommendations:

1. That Idaho Power would conduct a simulation analysis to examine what might have occurred if a decoupling or true-up mechanism had been implemented for Idaho Power at the time of the last general rate case and share those results with the parties.
2. That Idaho Power would develop and file an application with the Commission to implement a pilot energy efficiency program that would incorporate both performance incentives and "lost revenue" adjustments. (pp. 10–11)

On January 27, 2006, Idaho Power filed an application in Case No. IPC-E-04-15 requesting authority to implement a rate adjustment mechanism that would adjust the Company's rates upward or downward to recover the Company's fixed costs independent from the volume of the Company's energy sales. This type of ratemaking mechanism is commonly referred to as a "decoupling mechanism." However, Idaho Power believes that a more accurate description of what the Company is proposing is a "true-up mechanism." The true-up mechanism it is proposing, entitled "Fixed-Cost Adjustment," would be applicable only to Residential Service and Small General Service customers. This case is currently in process.

The Idaho Public Utility Commission has not yet reached a decision in the present Idaho Power rate application that would decouple revenues from utility earnings.

References

Idaho Public Utilities Commission. Various Years. Decisions and Orders in Dockets:

- Case No. IPC-E-04-15 on January 27, 2006, "In the Matter of the Investigation of Financial Disincentives to Investment in Energy Efficiency by Idaho Power Company."
- Case No. IPC-E-04-15. "Investigation of Financial Disincentives to Investment in Energy Efficiency by Idaho Power Company. Final Report on Workshop Proceedings." February 14, 2005.
- Case No. IPC-E-03-13, Order No. 29505. May 2004. Idaho Power Company General Rate Case.

New York

Overall Energy Efficiency Program Approach and Structure

New York established a state-wide systems benefits energy program administered by the New York State Energy Research and Development Authority (NYSERDA). Two public power authorities—the New York Power Authority and the Long Island Power Authority—

offer similar programs. Customers of regulated distribution utilities pay a non-bypassable system benefits charge as a separate line item.

Performance Incentives

Not applicable to the state-administered program.

Decoupling and Lost Revenue Recovery

New York is once again considering decoupling. On May 2, 2003, the NYPSC issued an order (Case 03-E-640) that instituted a proceeding "[T]o investigate potential electric delivery rate disincentives against the promotion of energy efficiency, renewable technologies and distributed generation." In its order, the NYPSC directed the administrative law judge to request, at a minimum:

- detailed "typical" bill analyses of possible impacts of alternative rate structures,
- comments on the degree to which current rate designs discourage electric delivery utilities from promoting energy efficiency, renewable technologies, and distributed generation,
- an indication of each of the electric delivery utilities of the feasibility of, and their interest in, making cost-based electric delivery rate design modifications for each service classification that remove such disincentives, and
- other recommendations to remedy any identified rate design disincentives against the promotion of energy efficiency, renewable technologies, and distributed generation.

The NYPSC defines decoupling this way in this docket:

> Revenue decoupling is defined as a rate making mechanism that is designed to eliminate or reduce the dependence of a utility's revenues on system throughput, adopted for the purpose of removing utility opposition to customer efforts to reduce energy consumption and demand or to install generation to displace electricity delivered by the utility's distribution and transmission system.

A technical conference was held to initiate the proceedings, after which time the NYPSC invited parties to submit comments on the issues identified at the conference and within the scope of the investigation. NYPSC staff did not submit comments, but did summarize comments received and provided its recommendations in a staff report issued July 9, 2004. Below are key findings given by NYPSC staff in this report:

- Staff's previous experience with comprehensive "revenue decoupling mechanisms" (RDMs) is that they tend to generate large revenue accruals, nearly all caused by weather.
- To the degree that unit prices are considered "too high" due to rate design measures such as volumetric rates, those rates create a strong incentive for customers to consider energy conservation, distributed generation or alternative energy sources.

While the proponents of RDMs argue that current rates provide a disincentive to utilities to promote energy conservation or distributed generation, the same rates provide a strong counter-balancing incentive to customers to engage in those practices. [emphasis added]

- While there may continue to be a financial disincentive in utility rate structures, in staff's view it is not enough to warrant implementation of RDMs.
- Rather than implementation of RDMs, staff recommends the continued development of better rate designs and, where appropriate, targeted mechanisms and performance incentives should be pursued.
- The application of focused performance incentives should be further explored, most appropriately within individual utility rate proceedings.

Based on these findings and analysis of the issues raised in the proceeding, staff issued the following recommendations in this report:

- While theoretically imposition of an RDM could resolve some of the conflicts [between utility revenues and profits to the throughput of the utilities' systems] as the proponents of the RDM concept argue, there are serious concerns with such an approach, such as the difficulty that would be involved in developing an appropriate mechanism and the risk of rate instability that might result.
- Further, other approaches, such as improved rate designs, targeted rate incentives, and performance incentives, may be just as effective as or even better than such a broad-based incentive ratemaking approach.
- Indeed, the various program initiatives identified above have achieved success without the need for a broad-based RDM, and other incentive approaches should be explored in the various utility rate proceedings as needed.
- *Accordingly, staff recommends than an RDM not be required at this time* [emphasis added].

A final decision in this investigation is still pending. The NYPSC has not issued an Order or other decision.

References

State of New York Public Service Commission. Various years. Case documents:

- Case 03-E-0640. "Staff Report: Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation." July 9, 2004.
- Case 96-E-0898. "In the Matter of Rochester Gas and Electric Corporation's Plans for Electric Rate/Restructuring Pursuant to Opinion No. 96-12" Settlement Agreement.
- Case 96-E-0897. "In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant PSL, Sections 70, 108 and 110, and Certain Related Transactions."
- Opinion 88-20, issued July 26, 1988.

Oregon

Overall Energy Efficiency Program Approach and Structure

The Energy Trust of Oregon, a nonprofit set up by the Oregon Public Utility Commission, is the administrator of the energy efficiency and renewable energy programs. A state agency, the Oregon Housing and Community Services, administers the low-income programs. The Education Service Districts administer the public purpose funding for the schools.

PacifiCorp and PGE collect 3% of billed revenues from ratepayers (with the exception of certain large customers who are allowed to invest the conservation and/or renewable portions of the public purpose charges in their own facilities). Distributions of fund allocations to program administrators occur monthly net of uncollectibles and administrative costs of both the utilities and the Oregon Public Utility Commission. Funding amounts are reported to the Commission. Public purpose funding sunsets for all programs in 2012 unless the Oregon Legislature renews it.

Oregon has established a statewide public benefits program for electricity and natural gas energy efficiency. The state's restructuring legislation (SB 1149) established a 3% "public purpose charge" on customer utility bills.

Performance Incentives

None is in place or proposed.

Decoupling and Lost Revenue Recovery

In the 1990s, Oregon established and used various mechanisms to remove utility disincentives toward energy efficiency investments, including lost revenue adjustments, shared savings, and decoupling. But none of these prior mechanisms are in effect because of the change in program administration and implementation.

While electric utilities were no longer expected to administer or implement programs, in 2002 Oregon implemented a decoupling mechanism for one of its large natural gas utilities, Northwest Natural. On September 12, 2002, the PUC issued an order (No.02-634) adopting a stipulation agreement allowing Northwest Natural Gas Company (NWN) to implement a Distribution Margin Normalization mechanism. (This was included in a package deal along with a very substantial funding mechanism [over 3% of total revenues] for "public purpose programs" to support low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs. The revenues for energy efficiency are provided to the Energy Trust of Oregon for administration.)

Oregon has since enacted decoupling for another of its natural gas utilities. A recent decoupling proposal by Cascade Natural Gas (Docket UG 167) was approved in early April 2006 (Order No. 06-191 entered 4/19/06) by the Public Utility Commission of Oregon.

Cascade's application for approval of its "Conservation Alliance Plan" (CAP) includes a decoupling mechanism consisting of two deferral accounts:

- One deferral account tracks changes in margin due to variations in weather-normalized usage, and
- The other deferral account tracks changes in margin due to weather that varies from normal.

The PUC also had considered a decoupling proposal for Portland General Electric, but rejected the proposal. We provide details of these cases in Appendix A because Oregon is the state with the greatest recent experience with decoupling.

References

Hansen, D.G. and S.D. Braithwait. 2005. *A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural.* Evaluation report prepared for the Oregon Public Utility Commission. Madison, Wisc.: Christensen Associates Energy Consulting. March 31.

Public Utility Commission of Oregon. Various years. Decision and Orders in dockets:

- Order No. 06-191, Docket UG 167. *In the Matter of Cascade Natural Gas Corporation Request for Authorization to Establish a Decoupling Mechanism and Approval of Tariff Sheets No. 30 and No. 30-A.* April 19, 2006
- Order No. 05-934, Docket UG 163. *NWN Joint Stipulation to Extend the Existing Decoupling Mechanism for Another Four Years.* August 25, 2005.
- Order No. 02-634, Docket No. UG 143. *In the Matter of Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization.* September 12, 2002.
- Order 02-633, Docket UE 126. *In the Matter of Portland General Electric's Proposed Tariffs to Decouple Distribution Revenues from Residential and Small Nonresidential Consumers and their kWh Sales.* September 12, 2002.
- Order No. 98-191. *In the Matter of the Revised Tariff Schedules in Oregon Filed by Pacificorp, dba Pacific Power and Light Company.* 1998.
- Order 95-322. *In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by Portland General Electric Company.* 1995.

Washington

Overall Energy Efficiency Program Approach and Structure

Washington is a non-restructured state. Utilities carry out DSM programs with regulatory oversight by the state's regulatory body, the Utilities and Transportation Commission. Utilities get cost recovery of energy efficiency programs through tariff riders. Program costs are expensed and trued up annually.

Performance Incentives

No performance incentive is in place or proposed. The Utilities and Transportation Commission (UTC) has established penalties for non-performance for Puget Sound Energy for not achieving energy savings targets.

Decoupling and Lost Revenue Recovery

In 1991, Washington Utilities and Transportation Commission adopted a revenue cap mechanism for Puget Sound Power Energy in order to decouple company revenues from energy sales. This "experimental rate design" was enacted in Docket Numbers UE-901183-T and UE-019184-P. In addition to the revenue caps, the WUTC established a "periodic rate adjustment mechanism" (PRAM). The WUTC explained its reasoning for taking this action, including a note about not instead using some type of "lost revenue adjustment" in the following excerpt:

> [T]he revenue per customer mechanism does not insulate the company from fluctuations in economic conditions, because a robust economy would create additional customers and hence, additional revenue. Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor. The company would have an incentive to artificially inflate estimates of sales reductions while actually achieving little conservation.

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 following enactment of decoupling, there were dramatic improvements in energy efficiency program performance. In an order (11^{th} Supplemental Order, Sept 21, 1993), the WUTC observed:

> PRAM 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 considered a national leader in this area.

This supplemental order extended PRAM another 3 years. In 1995, the WUTC approved a request from Puget and several other parties to terminate a set of rate adjustment mechanisms, including the revenue-per-customer cap, as part of a litigation settlement. The WUTC approved the request adopting an alternative set of rate proposals, which ended decoupling for Puget Sound Energy. However, the proposal itself brought before the WUTC expressly reserved the right of all parties to bring forth in the future "other rate adjustment mechanisms, including decoupling mechanisms, lost revenue calculations [and] similar methods for removing or reducing utility disincentives to acquire conservation resources."

Decoupling is once again being actively investigated and proposed in Washington. The Washington Utilities and Transportation Commission has considered (or is considering) decoupling both in a rulemaking docket and in individual utility rate cases. On March 31, 2005, the WUTC began its rulemaking inquiry into decoupling when it issued CR-101, "Preproposal Statement of Inquiry Concerning the Possible Issuance of Administrative Rules for Natural Gas Companies Pertaining to Rate and Accounting Methods to Separate or 'Decouple' Utility Recovery of Fixed Costs from the Volume of its Commodity Sales." This commenced WUTC Docket No. UG-050369, "Natural Gas Decoupling Rulemaking."

In May 2005 the WUTC held a workshop that was "intended as a forum for open discussion of alternative approaches to natural gas decoupling, as well as an opportunity for parties to identify potential issues or concerns associated with use of various types of decoupling methodologies." Following the workshop, the WUTC issues a Notice of Opportunity to File Written Comments. Numerous parties filed written comments. On Oct 17, 2005, the WUTC withdrew its rulemaking on decoupling and closed the docket. The UTC noted in its decision:

> The comments provide a wide spectrum of views on decoupling and highlighted a number of issues that require more detailed thought…..The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking.
>
> The Commission's decision is not intended as a comment on the viability of any specific decoupling proposal that has been discussed and considered in this docket. (Docket UG-050369)

In its ruling, "Summary, Analysis of Comments and Decision to Close Docket without Action," the WUTC identified key issues with enacting decoupling, namely:

a) *Scope of events covered by decoupling?* Weather impacts? All-inclusive (all impacts including energy efficiency/conservation)?
b) *Scope of customer classes included?* Residential only? Small commercial? All commercial/industrial? All classes? Cost allocation accordingly?
c) *Scope of the measurement and subsequent rate impacts?* Decoupling applied to individual customers? Across all customers in a class? If cost reductions achieved are spread out over entire rate class, does this encourage and/or provide correct incentives for such actions? Equity?
d) *Timing of adjustments: deferral with annual true-up vs. monthly adjustments?* Administrative efficiency versus more timely feedback to customers from actions?
e) *New customer impacts?* How to account for growth in number of customers? Impacts on fixed cost recovery?
f) *Rate of return implications?* Does decoupling materially reduce the risk associated with investment in a gas utility?
g) *Low-income customer considerations?* Since low-income customers tend already to be low volume customers, do decoupling mechanisms affect them adversely and disproportionately?

h) *Pilot project implementation approach?* Should a pilot program be tried first?
i) *Basic charge increase alternative?* Should the Commission be open to covering all fixed costs through a uniformly applied customer charge?
j) *Earnings cap or other mechanism to avoid windfalls?* Should measures be built in to protect against windfall recoveries caused by operation of the mechanism?
k) *Need to set fixed cost level in general rate case?* How much data does the Commission need to make an informed decision on any decoupling proposal?
l) *Proper way to measure weather impacts?* Best way of measuring deviations from normal weather for rate adjustment purposes?

In this Summary, the WUTC only identified the above issues. It did not describe possible approaches to address the issues and did not offer recommendations on any such approaches. As noted earlier, the WUTC concluded that decoupling was more appropriately addressed in the context of specific utility rate cases rather than a general rulemaking docket. Such individual cases have arisen, as we describe next.

PacifiCorp proposed a decoupling mechanism in a recent general rate case before the WUTC (Docket No. UE—50684). The decoupling proposal in this case was a response to an earlier Docket (UE-032065), in which WUTC ordered, "PacifiCorp may propose a true-up mechanism, or some other approach to reducing or eliminating any financial disincentives to DSM investment. This could be in connection with a general rate proceedings such as the Company suggests will be filed sometime in 2005."

In its recent rate case, concluded April 17, 2006 (Docket No. UE-050684), PacifiCorp (Pacific Power) sought to establish three "key regulatory mechanisms" to support "continued reliable operations." One of these three goals is to develop and adopt a decoupling mechanism to support implementation of energy conservation programs. The Natural Resources Defense Council submitted a "Joint Proposal" with PacifCorp for a 3-year pilot test of a true-up (decoupling) mechanism.

The WUTC denied the request by Pacific Power for the rate increase, which included the proposal for a pilot decoupling mechanism. The case involved a "long standing dispute over how to allocate costs in the utility's six-state territory." According to a WUTC press release on its decision:

> In rejecting the allocation formula, the UTC found that the company failed to carry the burden it alone bears to prove that resources in its eastern service territories, remote from Washington, provide tangible and quantifiable benefits to customers in this state.

Rejection of this proposal does not close the door to future consideration of decoupling. As noted in a WUTC press release (WUTC 2006), "In its order, the commission said that while it would support a well-designed decoupling program, it could not approve a proposal for PacifiCorp until it determined the proper allocation of the utility's costs to Washington."

The WUTC is presently considering another decoupling proposal in a different general rate case. Cascade Natural Gas Corporation has sought to establish a decoupling mechanism in its recent general rate case (UG-060256). The Company filed its application on February 14, 2006.

References

[WUTC] Washington Utilities and Transportation Commission. Various years: Decisions, Orders, Filings and Proceedings:

- Docket No. UG-060256. *Cascade Natural Gas Corporation, 2006 General Rate Case Application.*
- Docket No. UE-050684. *PacifiCorp (Pacific Power). General Rate Case Application.* Final Order issued April 17, 2006.
- Docket No. UG-050369. *Rulemaking to Review Natural Gas Decoupling, Notice of Withdrawal of Rulemaking* and *Summary, Analysis of Comments and Decision to Close Docket without Action.* October 17, 2005;
- Docket No. UG-051651. *Application for an Order Authorizing the Establishment of a Decoupling Mechanism and Deferred Accounting Treatment for Changes in Margin Due to Conservation and Due to Variances from Normal Weather Decoupling Mechanism Proposal.* December 2005.
- Docket UE-920433. *11th Supplemental Order.* Sept. 21, 1993.
- Docket Numbers UE-901183-T and UE-019184-P. *Puget Sound Power Energy General Rate Case Application.* 1991.

Other Examples

There are a few other jurisdictions that either have decoupling in place or are actively considering proposals to enact decoupling. In this section, we present short summaries of a few of these other cases.

Maryland

Maryland has had a decoupling mechanism for Baltimore Gas & Electric (BG&E) since 1998 and just recently enacted the same mechanism for its other principal gas utility, Washington Gas. The decoupling mechanism consists of three parts: (1) base revenues are set based on weather-normalized patterns of consumption, (2) monthly revenue adjustments are accrued based on actual revenues, and (3) monthly adjustments to rates are made based on the accrued adjustments. The intent of this mechanism is to decouple weather and energy efficiency impacts from the revenue ultimately recovered by gas companies. Another main objective is to provide revenue stability to the companies.

The energy efficiency impacts on revenues are only those achieved by customers without the support or funding provided by utility or other types of utility-sector energy efficiency programs. BG&E and Washington Gas do not fund or provide energy efficiency programs, and Maryland has no statewide “public benefits” program in place. The only exception is that the utilities do fund and administer programs for low-income residential customers.

These cases in Maryland provide concrete examples that decoupling mechanisms alone are not sufficient to lead to significant investments by utilities in energy efficiency. Other mechanisms, policies, and regulatory requirements are required.

New Jersey

On October 12, 2006, the New Jersey Board of Public Utilities approved two pilot programs for natural gas conservation for the South Jersey Gas and New Jersey Natural Gas companies. These pilot programs include provisions for decoupling so that gas cost savings (through improved energy efficiency) will not be offset by costs related to reduced usage. Details of this mechanism and other aspects of this decision were not available as this report went to press. It is noteworthy that these decoupling mechanisms were part of a package that includes plans to promote greater energy efficiency and to provide incentives (via decoupling—not "performance incentives" as described in this report) to the gas companies to promote energy conservation.

North Carolina

Piedmont Natural Gas Company

In October 2005, the North Carolina Utilities Commission issued "Order Approving Partial Rate Increase and Requiring Conservation Initiative" in Docket No. G-9, Sub 499; Docket No. G-21, Sub 461; and Docket G-44, Sub 15. In this order, the Commission approved an experimental conservation tariff, called the "customer utilization tracker" (CUT) in order to align the interests of company shareholders with those of customers regarding conservation initiatives. This tariff is effective for the 3-year period, November 1, 2005 to November 1, 2008. During the life of the CUT, Piedmont is also to contribute $500,000 per year toward conservation programs. The company is to work with attorney general and utilities commission staff to "develop appropriate and effective conservation programs to be submitted to the Commission for approval and annual review."

The status of this mechanism is unclear at the present time. The North Carolina Attorney General has filed a notice of appeal challenging the North Carolina Utilities Commission's legal authority to approve the CUT.

While the ultimate resolution of this issue is not known, this case provides a good illustration of the desirable tactic of tying decoupling to other provisions or requirements for specific funding of energy efficiency programs.

References

North Carolina Utilities Commission. 2005. *Order Approving Partial Rate Increase and Requiring Conservation Initiative.* Docket No. G-9, Sub 499; Docket No. G-21, Sub 461; and Docket G-44, Sub 15. October.

New Mexico

In the Energy Efficiency Act of 2005, the New Mexico Legislature recently passed enabling legislation for utility DSM, and this legislation calls for removal of financial disincentives towards energy efficiency. Nothing is yet in place.

Utah

The Public Service Commission of Utah approved a decoupling mechanism for the Quester Gas Company on October 5, 2006 in Docket No. 05-057-T01. This mechanism establishes a "Conservation Enabling Tariff (CET)" Pilot Program for a 3-year period. CET is to address the issue of declining usage per customer while removing the disincentives for Questar Gas to implement demand-side management programs, which Questar Gas committed to undertake in the settlement in this docket. The basic approach of this tariff is to determine "non-gas revenue" per customer and use a balancing account with periodic true-ups to meet established utility revenue requirements.

The Conservation Enabling Tariff methodology consists of three steps:

1. The allowed GS-1 distribution non-gas revenue (DNG) per customer per month is calculated. The revenue requirement and the year-end customers are allocated to the calendar months based on historical patterns. The monthly revenue requirement is then divided by the monthly number of customers to arrive at the allowed revenue per customer per month. The proposed revenue per customer will be based on projected year-end 2005 customers and the revenue collected from these customers using the rates proposed to be effective on January 1, 2006.
2. On a monthly basis, the allowed DNG revenue per customer each month is multiplied by the actual number of GS-1 customers. The product is compared to the actual GS-1 DNG revenue and any difference, higher or lower, is booked into a balancing account.
3. On a schedule of not less than twice per year, the Company will file for a percentage adjustment to the GS-1 DNG block rates in an amount to amortize the balancing account over the projected sales for the upcoming 12 months.

References

Public Service Commission of Utah. 2006. *Order Approving Settlement Stipulation: In the Matter of the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders.* Issued October 5.

Questar Gas Company. 2005. *Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy, for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders.* Docket No. 05-057-T01. December 16.

APPENDIX C: CASE STUDIES OF LEADING STATES WITH DECOUPLING OR SHAREHOLDER MECHANISMS IN PLACE

Performance Incentives: Massachusetts

Massachusetts has had shareholder incentive mechanisms in place since 1998. The original order that established the mechanism (Order 98-100) set the incentives based U.S. Treasury bills. Specifically (Section 5.3 of Order 98-100):

> Calculation of Shareholder Incentives
> A Distribution Company that achieves its design performance level shall calculate its after-tax Shareholder Incentive as the product of (1) the average yield of the three-month United States Treasury bill (as defined below), and (2) total program implementation costs as included in a distribution company's Energy Efficiency Plan. The average yield of the three-month United States Treasury bill shall be calculated as the arithmetic average of the yields of the three-month United States Treasury bills issued during the most recent twelve-month period, or as the arithmetic average of the three-month United States Treasury bill's twelve-month high and twelve-month low.
>
> A Distribution Company shall calculate its after-tax Shareholder Incentive as the product of (1) the percentage of the design performance level achieved, and (2) the design performance Shareholder Incentive level, provided that a Distribution Company shall earn no Shareholder Incentive if its actual performance is below its threshold performance level, and shall earn no more than its exemplary performance level Shareholder Incentive, even if its actual performance exceeds its exemplary performance level.

Section 5.2 of Order 98-100 defines three levels of performance:

> (a) The design performance level shall represent the level of performance that the Distribution Company expects to achieve in the implementation of the Energy Efficiency Programs included in its proposed plan (i.e., a Distribution Company that achieves 100 percent of its performance goals would reach its design performance level). The design performance level shall be expressed in levels of savings, in energy, commodity and capacity, and in other measures of performance as appropriate.
> (b) The threshold performance level shall represent 75 percent of a Distribution Company's design performance level.
> (c) The exemplary performance level shall represent 125 percent of a Distribution Company's design performance level.

As described above, the incentives were initially set at levels based on U.S. Treasury bills returns. However, in 2001–02 the returns on Treasury bills plummeted, which reduced the shareholder incentive returns accordingly. The resulting shareholder incentives were too low to be effective reward mechanisms. Consequently, the utilities came to DOER to seek an alternative basis for the performance incentive. DOER changed the basis for the performance incentive; it set the incentive rate to be 5% for achieving the design performance level. DOER also used this opportunity to “harmonize” the way the incentives were structured across all the affected utilities—taking a more uniform approach than had been in practice prior to this change.

Because of the drop in the value and returns on treasury bills, the utilities file annual “exceptions” to 98-100—with 5% as the design performance level. Exemplary performance is now defined at 110% of targets, yielding a maximum incentive at 5.5 %. Threshold performance is still 75% of targets. However, there is a separate account—“tax liability for performance incentives”—that the utilities manage, which effectively boosts the “before-taxes” shareholder incentive maximum to 9% of the program costs for meeting the exemplary level of performance. This “tax liability” account is used so as to not negate the intended effect of the shareholder incentive. Without this accounting (authorized by DTE), the utilities would earn substantially less than the 5% established for meeting design performance (the tax liability of these additional earnings would mean that the net incentive would be roughly reduced by about half).

There are three components to the shareholder incentive mechanism:

(1) Savings metric: The whole portfolio performance in lifetime MWh and kW savings as well as quantified “non-energy benefits” (NEBs).
(2) Value metric: The total value of all benefits minus all costs (essentially the “total resource cost” test—TRC).
(3) Performance metric: Other program elements not captured in savings or value metrics, generally tied to measures of program participation or market share. For example, the share of new homes that meet ENERGY STAR standards.

These metrics are weighted to arrive at the final shareholder incentive amounts. Present weights in use are 20% for the performance metric, 45% for the savings metric, and 35% for the value metric. These are subject to change with annual filings—but generally these fractions say about the same (maybe change 5%).

Determination of key values used in establishing the metrics is done through a collaborative process. Every two years, a New England “Collaborative” conducts an in-depth analysis of “avoided energy supply components” that determine values of detailed elements of electricity supply system for New England. This process had started in Massachusetts, but became a biennial regional effort because of the close relationships among the region’s utilities.

Utilities file annual plans and reports. DTE is responsible for reviewing and approving plans, making sure that the programs are cost-effective (i.e., provide net benefits to customers). DOER oversees the programs’ designs and budgets. Every year new goals are established—which also means that “shareholder incentives” are established annually, too.

Order 98-100 established a new approach and process for the design, review, and implementation of utility energy efficiency programs. A DOER staff person we interviewed noted that beginning with 2003 filings and data, DOER is just starting to compile "good" data in a comprehensive database. He added that the utility staff and stakeholders have a lot of experience—and the type and quality of data reflects this. Massachusetts now has really good planning numbers to use on energy efficiency and DSM—numbers based on accurate, detailed data on specific program measures and performance.

The utilities' evaluations are the basis for the values of the metrics used to determine shareholder incentives. There is some interaction between utility program evaluators and stakeholder groups. Every company files plans and evaluations annually. DTE reviews and approves the savings estimates (for overall portfolios) and determines the final performance values used to determine shareholder incentive values. Usually these are not controversial proceedings.

The utilities statewide spend roughly $120 million/year on programs—and the data show that the shareholder incentive amounts total about $5.5 million—and this is without considering the "tax liability" accounts, which are kept and tracked separately. Utilities account for this as a "transfer payment"—and the amount is typically about $4 million—making the total effective shareholder incentive to be about $9.5 million before taxes.

National Grid's 2004 Shareholder Incentive Mechanism Results

One of the major utilities, National Grid, reports that it generally has earned the shareholder incentive mechanism somewhere between the "design" and "exemplary" levels (5 to 5.5% after tax earning). National Grid generally has earned about $4 million/year on a total energy efficiency program annual budget of about $50 million.

The table below provides complete details of the "earned shareholder incentive" for National Grid according to its *2004 Energy Efficiency Annual Report*.

Table C-1. National Grid Earned Shareholder Incentive 2004

Total actual energy efficiency program expenses		$50,338,638
Component 1	Savings metric	$1,065,612
Component 2	Value metric	$746,911
Component 3	Performance metric	$801,735
Grand total: After-tax incentive		$2,614,258
Grand total: Before-tax incentive		$4,301,536

National Grid earned 104% of the available "design incentive" level for 2004 (threshold performance would be 75%; exemplary [maximum] performance would be 110%).

NSTAR Electric's 2004 Shareholder Incentive Mechanism Results

NSTAR Electric also has been successful in meeting established performance targets and receiving a significant shareholder incentive. As with National Grid, NSTAR's mechanism is composed of three components: (1) savings metric, (2) value metric, and (3) performance metric. In 2004, NSTAR Electric earned 101% (after tax) of the available design level shareholder incentive. Table C-2 provides summary data on this mechanism. The target incentive level available is 5% of total energy efficiency program expenses.

Table C-2. NSTAR Electric Earned Shareholder Incentive 2004

Total actual energy efficiency program expenses		$52,989,647
Component 1	Savings metric	$1,018,783
Component 2	Value metric	$788,187
Component 3	Performance metric	$863,543
Grand total: After-tax incentive		$2,670,513
Grand total: Before-tax incentive		$4,394,098

References

See “Massachusetts” summary in Appendix A.

Decoupling: Oregon

Oregon is the pre-eminent available exhibit for evaluating recent decoupling policy, because it is the only jurisdiction in the U.S. that has had a current decoupling policy in place long enough to have conducted an ex-post assessment of effectiveness. The following material provides a brief synopsis of key events and results.

In September 2002, in Order No. 02-634, Docket No. UG 143, the Oregon PUC adopted a stipulation agreement submitted by Northwest Natural Gas Company and a number of other parties. The agreement called for the implementation of a decoupling mechanism, along with the company agreeing to collect and pass through substantial revenues to support energy efficiency programs (to be administered by the Energy Trust of Oregon).

The decoupling mechanism that was established for Northwest Natural has the following key provisions:

- Approach is to true-up actual to expected revenue per customer.
- Partial decoupling: true-up 90% of difference.
- Actual usage is weather normalized (there is a separate mechanism to address usage variations due to weather).
- Applies to residential and commercial customers only.
- Company had run energy efficiency programs, but this responsibility was transferred to the Energy Trust of Oregon (along with the funding revenues described earlier).
- Service quality measures were adopted.

The Company’s interest in decoupling was mainly driven by interest in reducing risk and its cost of capital. Decoupling picks up other effects on usage, such as price changes, economic activity, and weather. The Commission’s key interest is noted below:

> The conceptual purpose of decoupling has always been to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict. The stipulated mechanism will allow NW Natural to provide customer service support and information related to energy efficiency without causing a negative financial impact on its shareholders. (Order 02-634)

Specific details of the mechanism are described in Order 02-634; an excerpt is given below:

> Also on October 1, 2002, NW Natural will implement a partial decoupling mechanism, under which it will defer and subsequently amortize 90 percent of the margin differentials in the residential and commercial customer groups. Marginal differentials are the margins associated with the difference between each group's weather-normalized usage and usage baseline. The deferral for each monthly period would be a credit (refund) if the calculation is positive or a debit (charge) if the calculation is negative.
>
> The stipulating parties emphasize that the decoupling mechanism will be applied to weather-normalized usage. When the company calculates variations from baseline volumes each month, it will adjust actual volumes to account for abnormal weather using the approach to weather normalization adopted in UG 132. The decoupling adjustments would be determined based on a monthly comparison of weather-normalized usage to baseline volumes resulting from actual customer counts. NW Natural will defer and amortize 90 percent of margin differentials due to each month's decoupling adjustments, with interest.

NW Natural's experience with decoupling was independently evaluated in 2005. This evaluation is the only such evaluation that we found of a modern (post-2000) experience with decoupling. Consequently, the results described in this evaluation are especially noteworthy. Below is a key finding from this independent evaluation (Hansen and Braithwait 2005):

> An examination of the theoretical effects of DMN [distribution margin normalization] leads us to conclude that it is an effective means of reducing NW Natural's disincentive to promote energy efficiency. This conclusion is reinforced by NW Natural's actions under DMN, which include effectively partnering with the Energy Trust of Oregon, improving HEF [high efficiency furnace] program performance, and shifting marketing resources towards energy efficiency programs.

The evaluation also found that DMN "…[H]as improved NW Natural's ability to recover fixed costs." Further, "[B]y reducing revenue fluctuations DMN has reduced NW Natural's risk." As to changing risks to customers, the evaluation was also positive: "We conclude that a shift of economic risk from NW Natural to its customers does not occur in NW Natural's service territory." This mechanism was also found not have affected NW Natural's incentives to provide high quality customer service.

The study found that the impact on customers of the resulting DMN adjustments was relatively modest. The first-year impact was about a 3% adjustment, which they felt was larger than expected due to the fact that the initial baseline was set just before a period of large price increases, which affected the relatively large first-year adjustment. In the second full year, the DMN adjustment was miniscule, only about 0.1%

The independent study summed up its assessment by leading off its “Recommendations” section as follows:

> Based on the information and input that we have received and reviewed, we recommend that some form of revenue decoupling be retained. It has been effective in reducing the variability of distribution revenues and in altering NW Natural’s incentives to promote energy efficiency. While DMN does not provide an *incentive* for NW Natural to promote energy efficiency, it does remove most of the *disincentive* that exists with the standard rates.
>
> 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 DMN is beneficial for consumers. (p. 75)

Recommendations from this evaluation of NW Natural’s decoupling mechanism included some changes to improve its performance. One of the recommendations is simply:

> Consider adopting full decoupling. Because of its simplicity, full decoupling would be easier for customers to understand than the combination of DMN and WARM [weather adjustment rate mechanism].

On August 5, 2005, NW Natural filed a joint stipulation to extend the existing decoupling mechanism for another four years. No parties objected to the stipulation, and the Commission unanimously approved it by Order on August 25, 2005 (Order No. 05-934, UG 163).

Oregon also has considered decoupling for electric utilities. Decoupling was proposed by Portland General Electric in 2001 (Docket UE 126) in parallel with NW Natural’s proposal. However, the Commission denied PGE’s proposal (Order 02-633). The Commission did not accept PGE’s proposal for the following reasons cited in its order:

- Unlike NW Natural's proposal, PGE's decoupling proposed mechanism does not weather-normalize customer usages. Previous decoupling mechanisms "were designed to address disincentives for least-cost planning, not to reduce weather related risks." (p. 6)
- PGE's proposal relies on customer usage levels from a docket completed about a year prior to the present application (UE 115). The Commission observes that reductions in usages since that time caused by a recession and rate hikes would result "in an immediate and potentially significant price increase if the decoupling mechanism were implemented." (p. 7). PGE's proposal contains no commitment to submit a general rate in the near future. Consequently, "Neither the Commission nor the parties will have an opportunity in the near future to review PGE's costs and earnings under decoupling, or to examine whether the company's cost of capital should be adjusted to account for the risk-reducing mechanism." (p. 7).
- PGE's proposal does not contain additional benefits comparable to two specific benefits that are included in NW Natural's stipulated agreement (UG 143). These are: (1) a service quality measure that includes financial penalties for poor performance, and (2) a permanent transfer of its DSM and energy efficiency programs to an independent entity.

Oregon has recently enacted decoupling for another of its natural gas utilities. A decoupling proposal by Cascade Natural Gas (Docket UG 167) was approved in April 2006 (Order No. 06-191 entered 4/19/06) by the Public Utility Commission of Oregon. Cascade's application for approval of its "Conservation Alliance Plan" (CAP) includes a decoupling mechanism consisting of two deferral accounts:

- One deferral account tracks changes in margin due to variations in weather-normalized usage, and
- The other deferral account tracks changes in margin due to weather that varies from normal.

The stipulation agreement reached includes an important additional element of CAP for funding energy efficiency programs. Cascade is to provide public purpose funds to the Energy Trust of Oregon (the statewide public benefits program provider) and to community service agencies for general and low-income demand-side management programs in the company's Oregon service territories.

This new tariff for Cascade became effective May 1, 2006. The tariff includes an "earnings sharing mechanism" and a "service quality measure."

References

See "Oregon" summary in Appendix B.