Alternative Regulation for Pennsylvania DSM

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Executive Summary

Pennsylvania's Public Utility Commission has scheduled an *en banc* hearing on the efficacy and appropriateness of alternative regulation ("Altreg") methodologies, such as revenue decoupling, which remove disincentives for gas and electric utilities in the Keystone State to aggressively pursue demand-side management ("DSM") initiatives. Pacific Economics Group Research LLC is a leading provider of research and testimony on revenue decoupling and other forms of Altreg. The Natural Resources Defense Council has asked us to prepare this white paper and oral testimony on alternative regulation for DSM.

Using gas and electric power more efficiently is the cheapest and cleanest way to meet America's energy needs. There is enormous potential to save money, create local jobs, and reduce pollution by making use of the grid less peaked and improving the efficiency of buildings, processes, and energy-using equipment. DSM programs are needed to overcome the persistent market barriers that prevent customers from seizing these opportunities. Pennsylvania energy distributors are strategically placed to undertake many of these programs, but reforms in the existing regulatory system are needed for distributors to pursue DSM aggressively.

Traditional Regulation

The traditional approach to utility regulation discourages utilities from embracing the full potential of DSM programs. Under legacy rate designs, utilities have a "throughput incentive" to promote use of their systems because increased loads bolster revenue more than costs. This discourages DSM. Utilities may also be reluctant to implement time-of-use base rates and other rate designs that encourage customers to adopt DSM because of their increased exposure to demand volatility and unfavorable demand trends. DSM reduces utility costs, but the incentive to contain these costs can be weakened by frequent rate cases and cost trackers. Environmental costs of a utility's operations have little effect on its finances. For example, carbon taxes are uncommon and might in any event be flowed through to customers via cost trackers.

We conclude that utilities under traditional regulation have a material disincentive to embrace DSM, even when DSM meets customer needs at lower cost than grid service. The gravity of the DSM incentive problem is increasing in an era in which competition from alternatives to grid service is mounting and utilities are under pressure to reduce their environmental footprints.

Key aspects of utility behavior can and should be mandated. For example, regulators should play an active role in the design of standard tariffs. Where regulators and other policymakers can effectively administer mandates there is less need for utility incentives. Even where mandates are feasible, however, there are often benefits to complementing them with incentives that help align utility interests with the public's.

Remedies Considered

Six Altreg mechanisms are considered in the paper that are touted for their ability to encourage DSM.

Revenue Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Revenue decoupling systems have two basic components. A revenue decoupling mechanism tracks variances between actual and allowed revenue and adjusts rates to reduce these variances. With full decoupling, the utility's revenue matches the revenue regulators allow. A revenue adjustment mechanism escalates allowed revenue to provide relief for growing cost pressures.

Decoupling is particularly widespread in the US gas distribution industry, where it is currently used in twenty-three jurisdictions. In the electric utility industry, decoupling is currently used in fourteen jurisdictions, including three that neighbor Pennsylvania. Decoupling has been particularly favored in states that strongly support DSM. Use of decoupling is growing, with recent approvals for electric utilities in Maine, Minnesota, Ohio, and Washington state.

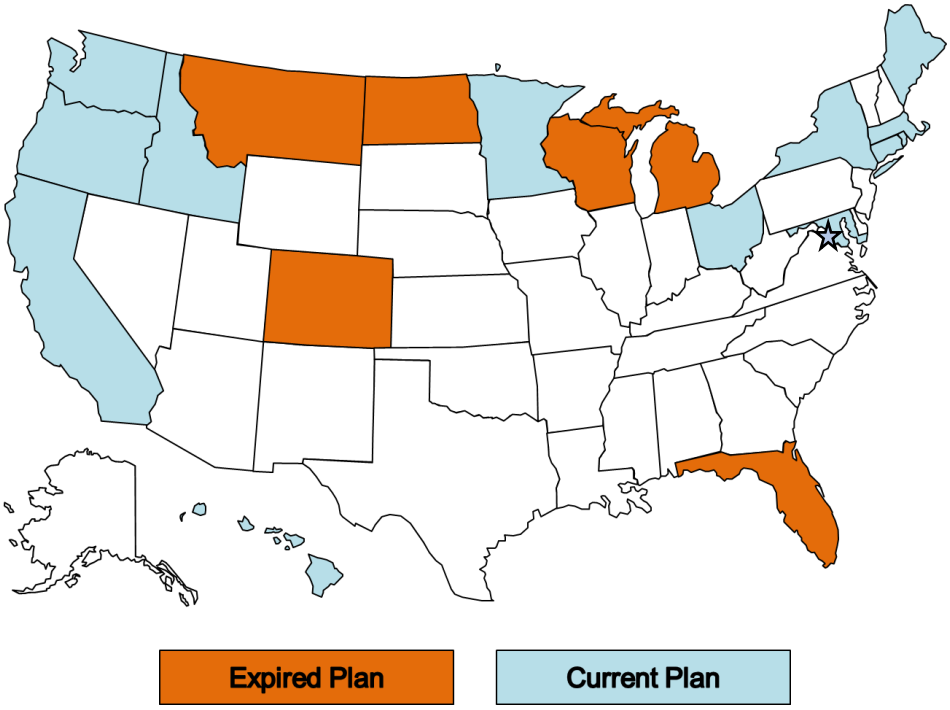
LRAMs

Under a lost revenue adjustment mechanism ("LRAM") a utility is compensated more selectively for the lost margins (base rate revenues) that are estimated to result from its DSM programs. This requires estimates of energy savings. LRAMs are more popular for electric than for gas utilities, due in part to the fact that electric utilities have larger DSM programs.

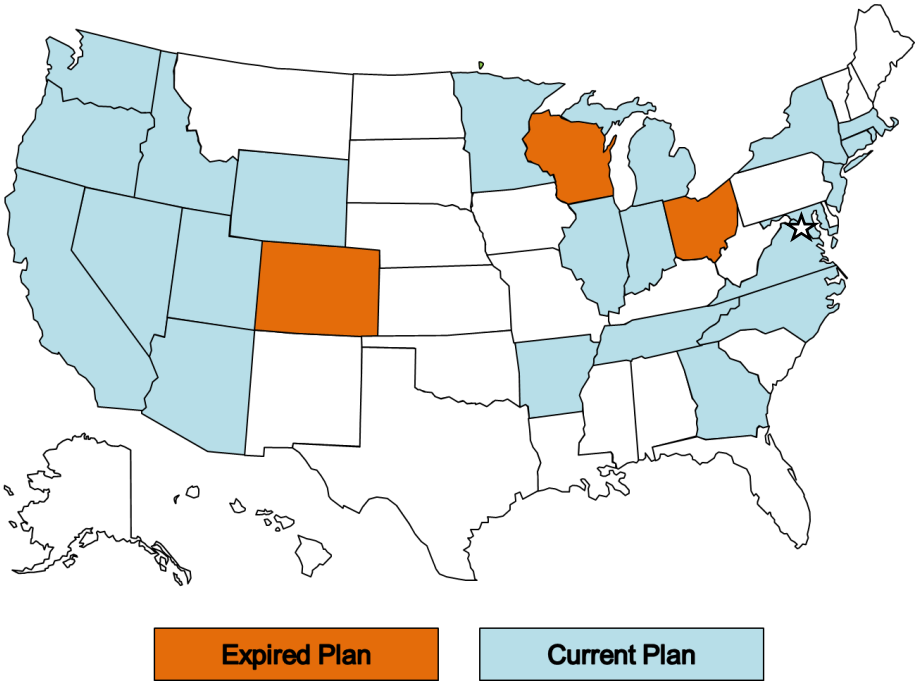
Fixed/Variable Pricing

Fixed/variable rate designs control the recovery, through customer and other fixed charges, of costs that are fixed in the short run with respect to system use. Customers pay a substantial fixed monthly charge for service regardless of their usage. This approach to pricing is more common for gas than electric utilities.

Electric Revenue Decoupling by State



Gas Revenue Decoupling by State



Tracking Utility DSM Expenses

Tracker treatment for utility DSM expenses removes the disincentive utilities have to spend money on DSM between rate cases. It thereby helps to tip the balance of incentives to embrace DSM. DSM program budgets sometimes grow rapidly. Most US energy utilities have tracker treatment for their DSM expenses today.

DSM Performance Incentive Mechanism

DSM performance incentive mechanisms ("PIMs") link a utility's revenue mechanically to its DSM performance as measured using metrics and targets. Utilities are commonly rewarded for DSM savings exceeding threshold amounts. Payments can be tied to estimated benefits of the scale of utility expenditures. PIMs to date have focused largely on conventional utility conservation programs. Roughly half of all US jurisdictions currently use DSM performance incentive mechanisms.

Multiyear Rate Plans

Multiyear rate plans combine moratoriums on general rate cases with revenue escalation using attrition relief mechanisms that operate independently of a company's specific cost. These arrangements can strengthen incentives to use DSM to contain capital expenditures and other costs. Some costs are addressed separately using trackers. Most plans also include PIMs for service quality. Use of multiyear rate plans is growing in the United States but is much more widespread abroad. Britain's RIIO approach to regulation, which has drawn considerable attention in the United States, features multiyear rate plans with revenue decoupling and numerous PIMs.

Recommendations

Relaxing the link between revenue and system use can play a key role in encouraging utilities to embrace DSM. Revenue decoupling is the preferred means of accomplishing this, for several reasons. The throughput-related disincentive is reduced or eliminated for the full range of utility initiatives that can encourage DSM. This is accomplished without complicated benefit calculations or restrictive rate designs that alternative methods require. Commissions can continue their traditional role of approving rate designs for standard tariffs which balance diverse considerations. In designing rates, Commissions should consider their impact on low use customers and the long run costs of using the grid.

Decoupling also has desirable side effects. Full decoupling, which encourages rate designs that foster DSM, also reduces the risk of demand volatility and declining average use from diverse sources. The revenue adjustment mechanism can provide responsible, automatic revenue escalation for

changing business conditions. The need for rate cases can be reduced when average use is declining. The diverse benefits of decoupling help to explain why it is widely used even where declining average use results chiefly from external sources rather than utility DSM programs. Several states use revenue decoupling for energy utilities even though DSM is chiefly undertaken by third parties. Approval of decoupling can be made conditional on commitment to DSM objectives.

Despite its many advantages, decoupling cannot by itself provide the incentives needed for utilities to fully embrace DSM due to the muted incentives utilities have to contain their costs. Utilities therefore need positive incentives to embrace DSM as a cost management tool.

Performance incentive mechanisms are used in many states to reward utilities for their DSM programs. The challenge today is to design demand side management PIMs that encourage a wide range of utility initiatives and transform markets. Multiyear rate plans can further strengthen cost containment incentives and the willingness of utilities to embrace DSM. Tracking utility DSM expenses can also encourage utilities to choose DSM as a cost containment strategy.

1. Introduction

The Pennsylvania Public Utility Commission has scheduled an *en banc* hearing on the efficacy and appropriateness of alternative regulation ("Altreg") methodologies, such as revenue decoupling, which remove disincentives for gas and electric utilities in the Keystone State to aggressively pursue energy conservation and efficiency initiatives. The Commission has stated an interest in learning (1) whether decoupling or other similar rate mechanisms encourage energy utilities to better implement energy efficiency and conservation programs; (2) whether such rate mechanisms are just and reasonable and in the public interest; and (3) whether the benefits of implementing such mechanisms outweigh the costs of their implementation. The Commission has issued a list of topics to guide the discussion.

Pacific Economics Group ("PEG") Research LLC is a leading provider of research and testimony on revenue decoupling, performance-based regulation ("PBR"), and other forms of Altreg. Work for diverse clients that include utilities, regulators, and environmental groups in the United States, Canada, and countries overseas has given us a reputation for objectivity and dedication to good regulation. We have been retained by the Natural Resources Defense Council ("NRDC") to prepare this white paper and oral testimony on Altreg for demand-side management ("DSM").

To evaluate the likely impact of revenue decoupling on DSM outcomes, an understanding of the implicit DSM disincentives created by traditional regulation is needed. Revenue decoupling can play a key role in removing some of these barriers, but by itself cannot address them all. It is thus desirable to consider revenue decoupling alongside other regulatory tools that can work together synergistically to achieve the desired effects. To assist the Commission in its deliberations, we therefore place revenue decoupling in a broader regulatory context.

The plan for the paper is as follows. In Chapter 2, we examine traditional retail rate regulation in the United States and consider why Altreg reforms are useful. Ways in which traditional regulation discourages DSM are highlighted. There follow in Sections 3-8 consideration of six Altreg tools that can impact the extent to which utilities embrace DSM.

- Revenue decoupling
- Lost revenue adjustment mechanisms
- Fixed/variable rate designs
- Tracking of DSM expenses
- DSM performance incentive mechanisms
- Multiyear rate plans

There are brief concluding remarks. An Appendix documents decoupling precedents and details the credentials of the authors.

2. Traditional Regulation and the Need for Altreg

2.1. Traditional Regulation

The traditional US approach to regulating retail rates of energy utilities developed over many decades.[1] In this system, sometimes called “cost-of-service regulation” ("COSR"), each utility’s rates are designed to recover its particular cost of providing service.[2] The chief means of setting rates under COSR is the general rate case. In these litigated proceedings, a revenue requirement is established that reflects the normalized cost of service in a test year. The prudence of costs must be assessed and a target rate of return on equity established.

The revenue requirement is allocated across the utility’s services. Rates are then designed to recover the revenue requirement for each service given assumptions about billing determinants (e.g.,

[1] The Federal Energy Regulatory Commission (“FERC”) uses a substantially different system to regulate interstate power transmission. Formula rate plans (a kind of broad-based cost tracker) are common.

[2] We discuss here the basic features of COSR, with the caveat that there are many variations on this theme in the United States.

energy consumption and peak demand). Most base rate revenue is drawn from volumetric and other usage charges that are so called because they vary with a customer's use of the system.[3] The balance of revenue is typically drawn from fixed customer charges.

To address certain costs more promptly than is possible through rate cases, regulators often use cost trackers. For example, large, volatile costs like those for fuel and purchased power are typically recovered with cost trackers. The remaining components of rates, which address costs of non-energy inputs such as labor, materials and capital, are called "base rates." Trackers are also sometimes used to compensate utilities for costs that are rapidly rising without producing much counterbalancing revenue. Costs associated with accelerated capital expenditures ("capex") are most commonly tracked using this rationale.

Utilities file rate cases when financial attrition is otherwise expected in the form of revenue that falls short of the cost of service. The timing of these cases is irregular and depends on business conditions. For example, rate cases tend to be more frequent when inflation is rapid or high capital expenditures are needed that do not trigger new revenue.

Trends in the demand for utility services are another important driver of potential attrition and rate case filings. Under traditional rate designs, growth in base rate revenue is chiefly driven by growth in system use. Cost is largely fixed in the short run with respect to system use but grows with customer connections and other dimensions of system capacity. The difference between the growth of system use and capacity is thus an important determinant of rate case frequency. Since capacity growth of gas and electric power distributors is highly correlated with growth in the number of customers they serve, this difference is well approximated by the trends in use per customer (aka "average use").

Residential and commercial use per customer grew rapidly in the electric power industry for decades until the early 1970s. This helped to finance capex without frequent rate cases. Growth in average use since then has been much slower. Details are provided in Table 1. Since 2007, the average use trends of many electric utilities have been close to zero or negative. The effect of this development on the frequency of rate cases has been temporarily mitigated by slow input price inflation. A large DSM program makes negative growth in average use more likely. Declines in average use were chronic in the gas distribution industry for many years but have been slowed recently by low gas prices.

[3] Volumetric and demand charges are the most common usage charges. Demand charges are based either on the customer's peak hourly receipts during the billing month or year, or its receipts at coincident (system) peaks. For commercial and industrial customers, demand charges collect most base rate revenue. For residential customers, base rate revenue is typically drawn chiefly from volumetric charges.

Table 1 Recent Trends in Average Deliveries of Electric Power to US Residential and Commercial Customers

	Residential				Commercial			
	Deliveries MWh	Customers	Average Use MWh / Customer	Growth Rates*	Deliveries MWh	Customers	Average Use MWh / Customer	Growth Rates*
1990	924,018,699	97,094,514	9.52		751,026,562	12,081,942	62.16	
1991	955,417,350	98,295,518	9.72	2.1%	765,663,613	12,178,694	62.87	1.1%
1992	935,938,788	99,512,728	9.41	-3.3%	761,270,543	12,367,205	61.56	-2.1%
1993	994,780,818	100,860,071	9.86	4.8%	794,573,370	12,526,377	63.43	3.0%
1994	1,008,481,682	102,320,846	9.86	-0.1%	820,269,462	12,733,153	64.42	1.5%
1995	1,042,501,471	103,917,312	10.03	1.8%	862,684,775	12,949,365	66.62	3.4%
1996	1,082,511,751	105,343,005	10.28	2.4%	887,445,174	13,181,065	67.33	1.1%
1997	1,075,880,098	107,065,589	10.05	-2.2%	928,632,774	13,542,374	68.57	1.8%
1998	1,130,109,120	109,048,343	10.36	3.1%	979,400,928	13,887,066	70.53	2.8%
1999	1,144,923,069	110,383,238	10.37	0.1%	1,001,995,720	14,073,764	71.20	0.9%
2000	1,192,446,491	111,717,711	10.67	2.9%	1,055,232,090	14,349,067	73.54	3.2%
2001	1,201,606,593	114,890,240	10.46	-2.0%	1,083,068,516	14,867,490	72.85	-0.9%
2002	1,265,179,869	116,622,037	10.85	3.7%	1,104,496,607	15,333,700	72.03	-1.1%
2003	1,275,823,910	117,280,481	10.88	0.3%	1,198,727,601	16,549,519	72.43	0.6%
2004	1,291,981,578	118,763,768	10.88	0.0%	1,230,424,731	16,606,783	74.09	2.3%
2005	1,359,227,107	120,760,839	11.26	3.4%	1,275,079,020	16,871,940	75.57	2.0%
2006	1,351,520,036	122,471,071	11.04	-2.0%	1,299,743,695	17,172,499	75.69	0.2%
2007	1,392,240,996	123,949,916	11.23	1.8%	1,336,315,196	17,377,219	76.90	1.6%
2008	1,380,661,745	125,037,837	11.04	-1.7%	1,336,133,485	17,582,382	75.99	-1.2%
2009	1,364,758,153	125,208,829	10.90	-1.3%	1,306,852,524	17,562,235	74.41	-2.1%
2010	1,445,708,403	125,717,935	11.50	5.4%	1,330,199,364	17,674,338	75.26	1.1%
2011	1,422,801,093	126,143,072	11.28	-1.9%	1,328,057,439	17,638,062	75.29	0.0%
2012	1,374,514,708	126,832,343	10.84	-4.0%	1,327,101,196	17,729,029	74.85	-0.6%
2013	1,394,812,129	127,777,153	10.92	0.7%	1,337,078,777	17,679,562	75.63	1.0%
2014	1,407,208,311	128,680,416	10.94	0.2%	1,352,158,263	17,853,995	75.73	0.1%
Average Annual Growth Rates*								
1991-2007				**1.0%**				**1.3%**
2008-2014				**-0.4%**				**-0.2%**

Source: U.S. Energy Information Administation
* Growth rates are calculated logarithmically

2.2. The Need for Altreg

Traditional regulation has some shortcomings that revenue decoupling and other forms of Altreg can address. Under unfavorable business conditions, frequent rate cases are required that raise regulatory cost and weaken utility performance incentives.[4] The cost burden is amplified when

[4] Rate cases nonetheless have benefits, which include the opportunity to review utility operations and provide feedback.

regulators must oversee numerous utilities. Rates may nevertheless be uncompensatory if rate cases do not use fully forecasted (aka forward) test years.

A number of tools can be used to reduce the cost of traditional regulation, but these can have undesirable side effects. For example, regulation can be simplified by expanding the array of costs eligible for tracking or by de-emphasizing prudence reviews. However, these measures weaken utility cost containment incentives.[5] Forward test years can make rate case adjustments more compensatory but complicate rate cases with controversies over future costs and system use.

Traditional regulation is well known to be problematic for demand-side management ("DSM") programs. Poor incentives to aggressively embrace DSM are the main problem. Traditional regulation incentivizes utilities to bolster average use. This phenomenon is often referred to as the "throughput incentive." DSM slows growth in average use, thereby eroding margins. Utilities may be reluctant to implement time-of-use base rates and other experimental rate designs that encourage customers to adopt DSM measures because of increased exposure to demand volatility and unfavorable demand trends.

Another problem is the incentives utilities can have under traditional regulation to use DSM as a cost management tool. For environmental groups such as the NRDC, a special concern is the indifference utilities have to improving the environmental impact of their operations. But utilities can also have poor incentives to use DSM to contain costs of service that affect the rates that they charge. For example, DSM can reduce opportunities for utilities to grow rate base. The problem is greatest for assets, such as substations, the need for which is closely tied to load. The need for transmission and distribution assets is especially sensitive to reductions in coincident peak loads.

The disincentive to facilitate DSM is offset to the degree that utilities can profit from slowing rate base growth. Under COSR, utilities benefit from slowing rate base growth only between rate cases. Any resulting reduction in the depreciated value of rate base in the test year for the next rate case is passed entirely to customers. For example, the portion of the revenue requirement corresponding to an aging distribution substation that has not been replaced due in whole or part to DSM is reset in the next rate case to its lower, more depreciated value. The incentive to contain rate base growth thus falls with the frequency of rate cases and the pervasiveness of trackers for load-related capex.[6]

[5] Trackers can be designed to strengthen cost containment incentives but typically are not.
[6] Capital cost trackers can be designed, however, to strengthen capex containment incentives.

Many other costs that are sensitive to DSM are recovered through trackers, and this also weakens incentives to embrace DSM. Most notable are the costs of fuel and purchased power.[7] For example, energy efficiency programs provide an opportunity for a distributor to reduce the cost of purchased energy, but the utility has little to no incentive to reduce energy costs if they are passed through to customers in a cost tracker.

We conclude that utilities under traditional regulation have a material disincentive to embrace DSM, even when DSM meets customer needs at lower cost than traditional grid service.[8] In addition, utilities are financially unaffected by other potential benefits of DSM. The DSM incentive problem is increasing in an era in which competition from alternatives to grid service is mounting and utilities are under pressure to reduce their environmental footprints.

In addition to incentive problems, DSM programs can place stress on a traditional regulatory system. Slower growth in average use increases the frequency of rate cases. This raises regulatory cost and weakens cost containment incentives.

2.3. Mandates Versus Incentives

Key aspects of utility behavior can and should be mandated. For example, regulators should play an active role in the design of standard tariffs to ensure that they send appropriate price signals to customers. Clean energy portfolio standards are also useful, and should include DSM. Where regulators and other policymakers can effectively administer mandates to guide utility behavior, there is less need for utility incentives.

Even where mandates are feasible, however, there are often benefits to complementing them with incentives that help align utility interests with those of the public. Not only can this decrease utility resistance to complying with unpalatable mandates, but it can result in increased enthusiasm and creativity on the part of utilities in pursuing regulatory goals. Properly incentivized utilities may, for example, use their considerable influence to proactively promote cost-effective DSM among customers and other stakeholders. Improving utility incentives can help achieve regulatory goals, while simultaneously decreasing the burden of regulation.

[7] Some utilities also have tracker treatment of transmission expenses.

[8] Under traditional regulation utilities are, in other words, incented to oppose efficient levels of DSM.

2.4. Criteria for Evaluating Alternative Decoupling Remedies

In this paper we consider six Altreg tools that have been touted for their ability to encourage DSM. Sensible criteria are needed to compare these options. Relevant criteria include the success of the approach in encouraging DSM, addressing attrition, and making regulation more efficient. Special features of particular mechanisms should also be considered.

3. Revenue Decoupling

3.1. The Basic Idea

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Revenue decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism. The RDM tracks variances between actual and allowed revenue, and adjusts rates to reduce these variances. Meanwhile, the revenue adjustment mechanism escalates allowed revenue itself, in order to provide relief for growing cost pressures. These mechanisms thus address different sources of financial attrition that utilities can experience between rate cases. The RDM addresses *revenue*-related (i.e., cost recovery-related) attrition, leaving the revenue adjustment mechanism to address *cost*-related attrition.

Revenue Decoupling Mechanisms

An RDM makes regularly scheduled adjustments to rates via a true-up mechanism. Such mechanisms usually involve a balancing account in which past differences between actual and allowed revenue are entered. The accumulated net variance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. This is usually undertaken with respect to usage charges, a practice that favors low usage customers. Rates rise when volumes are low but also fall when volumes are high.

RDMs can make true-ups annually or more frequently. The size of the rate adjustment that is permitted in a given year may be capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue, and they are often the primary focus of DSM programs.

RDMs also vary in terms of the services over which revenues are pooled for true-up purposes. In some plans all services are placed in the same "basket." Other plans have multiple baskets, which insulate customers of services in one basket from changes in revenue in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true-ups are sometimes allowed only for the difference between allowed revenue and the weather-normalized actual revenue. In contrast, an RDM that accounts for *all* sources of demand variance is called a "full" decoupling mechanism. With full decoupling, the utility receives no more and no less than its commission-approved allowed revenue.

Revenue Adjustment Mechanisms

The great majority of decoupling systems have a revenue adjustment mechanism since, if allowed revenue is static, the utility will experience financial attrition since cost tends to rise, for inflation and other reasons. It should also be remembered that revenue tends to rise with customer growth in the absence of decoupling. Utilities that lack revenue adjustment mechanisms in their decoupling systems often file frequent rate cases. Therefore, the important question in a proceeding to consider decoupling is not the need for a revenue adjustment mechanism, but rather its design.

Most approved revenue adjustment mechanisms escalate allowed revenue only for customer growth. This is sometimes accomplished indirectly by adjusting rates to hold revenue-per-customer constant. Customer growth is an important driver of cost, and is highly correlated with other cost drivers such as peak demand. The number of customers is always a highly significant variable in PEG's econometric studies of energy distributor cost. Escalating revenues in this way reduces the need for rate cases, but rarely eliminates them because cost also has other drivers, such as input price inflation.

This reality is illustrated in Table 2. We have gathered data from publicly available sources, such as the FERC and the US Energy Information Administration, on the distributor cost and number of customers served by a large and representative sample of electric utilities. The sample includes 50 power distributors designated as "major" by the Federal Energy Regulatory Commission. It includes both large and small companies that serve 35 states. It can be seen that average cost growth exceeded average customer growth in all but one of the twelve years considered. Annual cost growth exceeded customer growth by 165 basis points on average over the sample period.

Table 2 Trends in Power Distributor Cost and Customers (2002-2013)[9]

	Cost Growth	Customer Growth	Difference
2002	1.87%	1.35%	0.52%
2003	3.16%	1.36%	1.80%
2004	-0.23%	1.52%	-1.75%
2005	3.58%	1.61%	1.97%
2006	2.20%	1.16%	1.03%
2007	6.81%	1.49%	5.33%
2008	2.38%	0.67%	1.71%
2009	1.66%	0.27%	1.39%
2010	2.92%	0.35%	2.57%
2011	2.63%	0.21%	2.43%
2012	2.20%	0.28%	1.92%
2013	1.36%	0.51%	0.86%
Average	2.54%	0.90%	1.65%

******Growth rates are calculated logarithmically*

It follows that regulators can approve revenue-per-customer decoupling with little concern that it would produce overearning. When a revenue adjustment mechanism escalates allowed revenue only for customer growth, the utility usually retains the freedom to file rate cases to address other cost factors, and utilities in this situation often do so.

In some cases revenue adjustment mechanisms are "broad based," in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and thereby provide the foundation for a multiyear rate plan. Methodologies used to design broad-based revenue adjustment mechanisms include cost forecasts and inflation and productivity indexing.

[9] Data Sources: FERC Form 1 (cost data), EIA Form 861 (customers), and the Edison Electric Institute (allowed ROE). Cost is calculated as reported O&M expenses plus an estimate of capital cost. O&M expenses include the cost for the distribution and customer account functions plus an allocation of reported administrative and general cost. It excludes volatile cost items such as uncollectible accounts and pensions and benefits. The capital cost was calculated as the product of rate base and a rate of return plus depreciation.

3.2. Decoupling Precedents

Revenue decoupling has been widely adopted in the United States and abroad. American states that have tried gas and electric revenue decoupling are shown in Figures 1a and 1b, respectively. Table A1 in the Appendix details current revenue decoupling precedents in the United States and Canada.

Inspecting the figures, it can be seen that decoupling is currently used to regulate at least one gas or electric utility in more than twenty-five jurisdictions, including four of Pennsylvania's neighboring states. Decoupling is particularly widespread in the gas distribution industry, where it is used in twenty-two jurisdictions. This reflects the fact that declining average use by residential and commercial customers has been chronic in the industry. It is noteworthy that the declines have been chiefly due to business conditions that are outside of gas distributors' control. In the electric utility industry, decoupling is currently used in fourteen jurisdictions. It has been particularly favored in states that strongly support DSM. Use of decoupling is growing, with recent approvals for electric utilities in Maine, Minnesota, Ohio, and Washington state.

3.3. Decoupling Advantages

The numerous advantages of revenue decoupling have prompted the NRDC to strongly advocate its use as a component of modern regulation. We discuss here some of the most important advantages.

Encouragement of DSM

Decoupling can reduce or eliminate a utility's throughput-related disincentive for the full array of initiatives that can support DSM. Utilities are not harmed financially if their efforts slow growth in average use. Decoupling also makes time-of-use and other innovative rate designs that foster DSM less risky. It is important to note in this regard that the risk of rate designs with high volumetric and demand charges is reduced to the extent that earnings are decoupled with respect to *all* sources of demand volatility, including the business cycle and weather. This benefit of *full* decoupling true-ups is not widely recognized.

Revenue decoupling can play a substantial role in motivating utilities to pursue DSM. For example, in its most recent State Scorecard, the American Council for An Energy Efficient Economy ("ACEEE") reports net incremental savings from electricity efficiency programs as a share of 2014 retail

Figure 1a Electric Revenue Decoupling by State

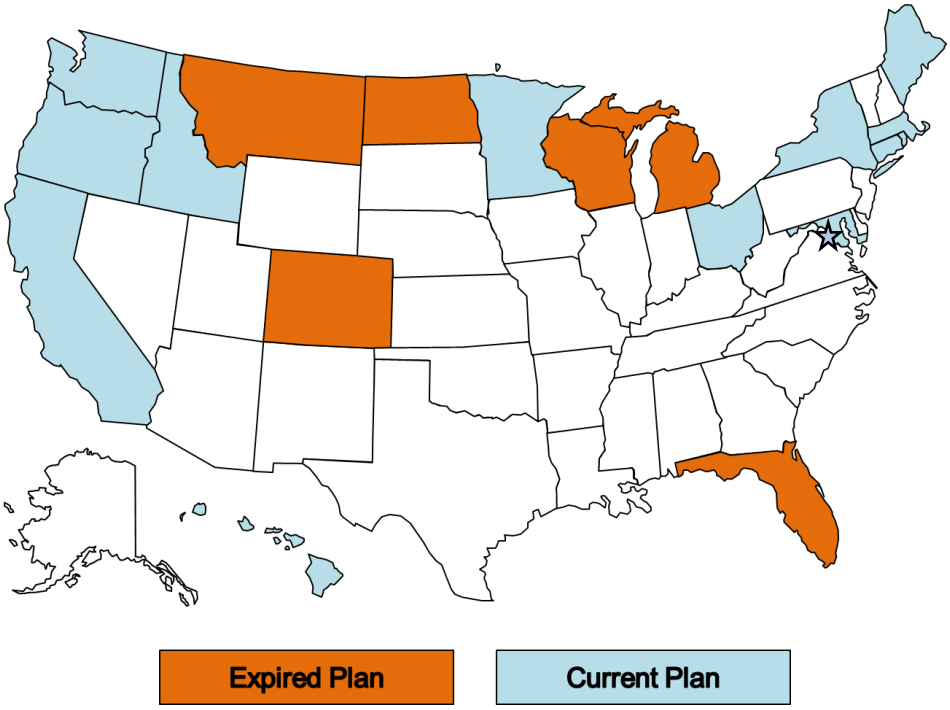
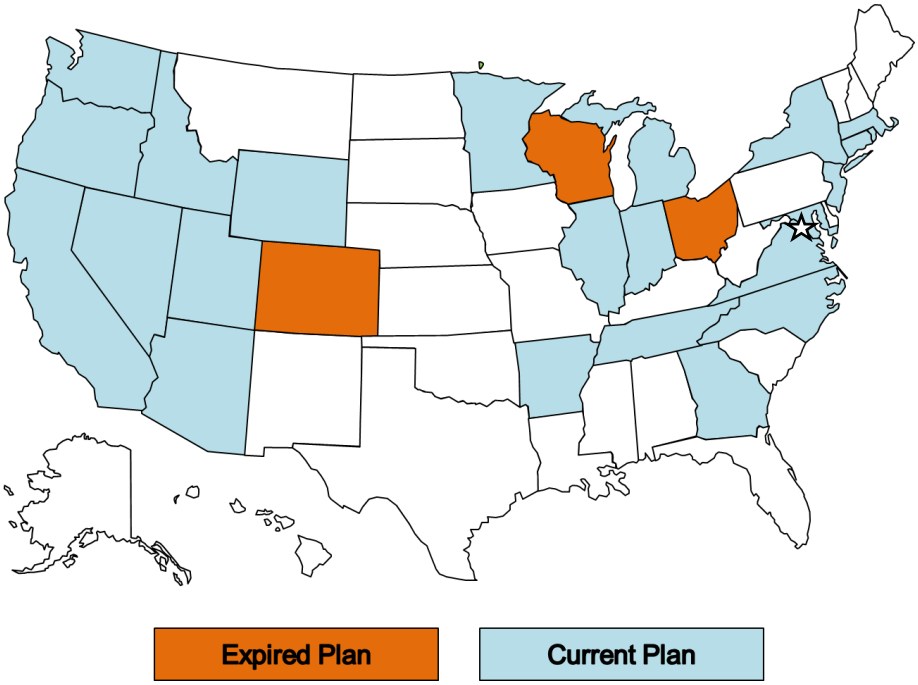


Figure 1b Gas Revenue Decoupling by State



sales.[13] Setting aside the states in which DSM programs are mainly administered by third parties, 8 of the 13 top-performing states employed electric decoupling at the time.[14] Among the remaining 29 states, only a single one had decoupling.

The benefit of eliminating the throughput incentive depends on the role utilities play in DSM promotion. If DSM programs are undertaken by independent agencies rather than by utilities, the impact of decoupling on DSM outcomes is lessened. However, utilities have many other ways to influence DSM, including their rate designs and support for large DSM budgets and tighter appliance efficiency standards and building codes. Decoupling has been used in seven jurisdictions (Hawaii, Maine, New Jersey, New York, Oregon, Washington DC, and Wisconsin) in which a sizable portion of DSM programs are not administered by utilities. One sign of the contribution decoupling makes to increasing utility support for DSM is the commitments some utilities have made, in settlements, to unconventional DSM initiatives as a condition for gaining decoupling plan approval.

- In a decoupling settlement with the Wisconsin Citizens Utility Board, Wisconsin Public Service agreed to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force. These addressed residential and commercial energy efficient building codes, state appliance efficiency standards, and non-regulated fuels efficiency and conservation.

- The Hawaii Clean Energy Initiative Agreement involved the three Hawaiian Electric companies, the state of Hawaii, and its Division of Consumer Advocacy.[15] This document contained commitments in more than thirty areas.

In addition, in an order approving a decoupling plan for United Illuminating ("UI"), the Connecticut Department of Public Utility Control stated that it was approving the plan *not* because of its effect on the company's DSM program itself, but for its effect on "areas where UI does not already receive incentives."[16] The Department goes on to explain that

> UI is still viewed as *the* energy provider by the general body of ratepayers. The Department believes that this will not change… Success in achieving Connecticut's energy policy goals requires that the Department take advantage of this relationship to

[13] In cases where 2014 data were unavailable, the ACEEE utilized 2013 data instead.

[14] Third parties, rather than utilities, are primarily responsible for DSM program administration in Delaware, Hawaii, Maine, New Jersey, New York, Oregon, Vermont and Wisconsin, as well as in Washington DC.

[15] "Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies," 2008.

[16] Connecticut DPUC, Decision in Docket 08-07-04, February 2009, p. 121.

promote the energy-related programs and policies that have been recently set in place.[17]

Attrition Relief and Revenue Stabilization

A second major advantage of decoupling is that it can address financial attrition from declining average use. Such attrition can result from large utility DSM programs, as well as from DSM programs managed by independent agencies, high prices for energy commodities, increasingly stringent building codes and appliance efficiency standards, net metering, and other policies that reduce energy use. Decoupling can help make utilities whole for attrition from all of these sources.

Decoupling can also help stabilize revenue in the face of short-run usage fluctuations resulting from changes in weather, the business cycle, and miscellaneous other economic conditions. Revenue from inverted block and time-of-use rates can be particularly sensitive to demand fluctuations.

While decoupling reduces revenue risk, it does not guarantee that a utility will recover all of its costs. A utility operating under decoupling must still manage its cost to ensure that it is equal to or less than the allowed revenue. This can be challenging, especially when the firm is operating under a multiyear rate plan.

Efficient Regulation

As for the regulatory efficiency of decoupling, it does add items to the regulatory agenda. Rates must be reset to effect revenue reconciliations, and a revenue adjustment mechanism is usually developed and instituted. However, the administrative cost of a decoupling true-up is not that different from the cost of administering cost trackers. For both, the appropriate revenue adjustment must first be ascertained and then allocated to service classes and recovered through a change in rates. The administrative cost of decoupling true-ups can be reduced by timing them to occur at the time of rate adjustments that are made for other reasons.

On the other hand, by addressing important sources of financial attrition, decoupling can permit a reduction in the frequency of rate cases. The reduction is modest in the case of the conventional revenue-per-customer decoupling but can be more substantial with a broad-based revenue adjustment mechanism. A single rate case can result in thousands or tens of thousands of pages of testimony and discovery documents. A desire to reduce the frequency of rate cases is an important impetus for regulators to approve cost trackers as well. Revenue decoupling can also help streamline rate cases. Controversy over billing determinants in rate cases with future test years is reduced. It is also

[17] Ibid, pp. 121-122.

noteworthy that revenue decoupling does not rely on complicated calculations to estimate the load savings from DSM programs. On balance then, revenue decoupling has the potential to *improve* the efficiency of the regulatory system in addition to eliminating the throughput incentive.

The benefits of improved regulatory efficiency achieved with decoupling can be realized in several ways. The cost of regulation may be reduced. Alternatively, increased efficiency may permit regulatory resources to be redirected to other areas. This possibility may be especially welcome in periods of rapid change in utility business conditions, when a host of new issues needing regulatory attention may arise.

3.4. Criticisms of Decoupling

Revenue decoupling does have critics. Some concerns are substantive but can be addressed by regulators in relatively straightforward ways, and some concerns are misplaced.

One substantive concern is that decoupling true-ups may cause customers in one rate class to absorb the impact of reduced loads in another class. For example, a drop in business sector demand might lead to an increase in residential bills. However, this issue can be addressed through the use of separate service baskets.

Another substantive concern is that decoupling may decrease utility incentives to respond to the needs and preferences of customers. Firms in competitive markets can suffer sharp reductions in sales when their terms of service are not competitive. However, the monopoly character of utility service limits the ability of customers to go elsewhere, and revenue decoupling can further reduce the chance of suffering financial harm when customers are dissatisfied. As a result, utilities that operate under decoupling may feel less pressure to offer services tailored to customer needs.[19] However, this can be addressed by developing service quality monitoring or incentive mechanisms that encourage the utility to be responsive to customer needs.

The demand of some customers *is* sensitive to a utility's rate and service offerings. An example is an establishment that consumes large amounts of power, and which is capable of developing self-generation capabilities or shifting its operations to another service. If the application of decoupling to such customers makes the utility less responsive to their needs, it could trigger the loss of some loads and a failure to attract new loads, to the detriment of the local economy. However, the risk of bypass

[19] A related concern is that decoupling weakens the incentive of regulators to avoid policies that could, by reducing sales volumes, otherwise compromise utility finances.

varies greatly by service territory, and in areas that are not heavily industrialized it is generally contained. Moreover, large industrial customers typically account for a small share of a power distributor's base rate revenue. Concerns about the treatment of demand-elastic customers can be mitigated by applying decoupling selectively to residential and small business customers, as well as by developing service quality monitoring or incentive mechanisms encouraging the utility to be responsive to customer needs.

Rate and Revenue Stability

Some critics of decoupling express concern that it can destabilize rates. Soft caps on revenue adjustments can mitigate this problem without weakening the incentive and attrition relief benefits of decoupling. Experience has shown that the increased volatility due to revenue decoupling is manageable. In a recent study of US electric and gas decoupling true-ups, Pamela Morgan found that most rate adjustments have been small (64% were within ±2% of retail rates, and roughly 75% were within ±3%). She also found that a significant share of these adjustments (38%) represented refunds to customers.[20]

Weakened Customer Conservation Incentives

It is sometimes argued that decoupling weakens customer incentives to pursue conservation. This argument is true with respect to fixed/variable pricing, with its low usage charges, but not with respect to LRAMs, DSM performance incentives, or decoupling. Under revenue decoupling, customers *as a group* must pay for the lost margins no matter how much they use the system but *individual* customers can reduce their distribution bills by conserving. The upward drift in volumetric rates that often results from decoupling can also incent individual customers to conserve more. In effect, the revenue requirement is a "hot potato" that individual customers are incentivized to reduce their exposure to by doing more conservation than their neighbors.

4. Lost Revenue Adjustment Mechanisms

4.1. The Basic Idea

Under a lost revenue adjustment mechanism ("LRAM") a utility is compensated more selectively for the lost margins (base rate revenues) that are estimated to result from its DSM programs, and

[20] Pamela Morgan, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations, Graceful Systems LLC, May 2013.

possibly from other volume drivers like distributed generation. This requires estimates of energy savings and other quantitative impacts of the programs. Compensation for lost margins is usually effected through a rate rider that can operate in years between rate cases. The utility is fully at risk for unforeseen fluctuations in demand due to weather, local economic activity, energy market prices, and other drivers of the demand for its services.

4.2. LRAM Precedents

Precedents for LRAMs are detailed in Figure 2 below. LRAMs are currently used in fifteen jurisdictions to regulate electric utilities. These mechanisms have special appeal to utilities that are experiencing some growth in average use. LRAMs are less popular for gas distributors since the declining average use they have typically experienced is due chiefly to external forces LRAMs don't address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large-load customers.

4.3. LRAM Pros and Cons

LRAMs can eliminate a utility's throughput-related disincentive to embrace DSM programs that are covered by the mechanisms. Attrition due to these programs is reduced, and this reduces the need for rate cases.

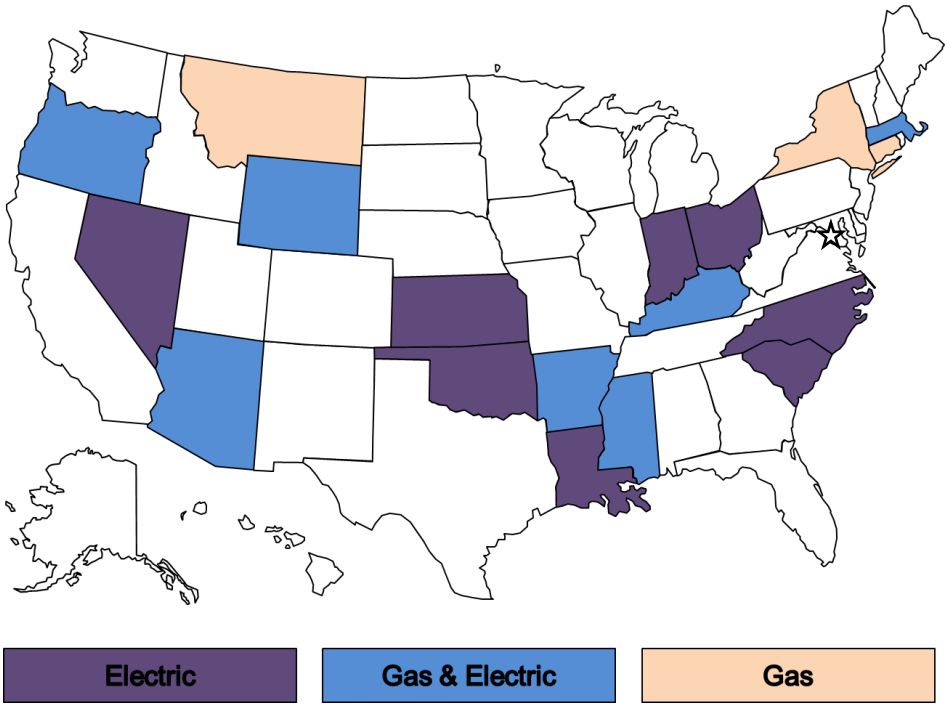
The many disadvantages of LRAMs have prompted the NRDC to oppose their use as a means for fostering DSM. The high cost of administering these mechanisms is a core limitation. It is challenging to estimate the impact of DSM programs in a world in which demand is affected by numerous other business conditions. The American Gas Association ("AGA") commented in a review of Altreg options that

> Lost margin trackers are complicated calculations that estimate the level of decreased distribution revenues caused by customer conservation. This requires an evaluation to distinguish between program-specific reductions in customer usage and other causes of reduced consumption. There is a great deal of uncertainty in the measurement of such reductions.[21]

Savings estimates are even more complicated for less conventional utility initiatives such as innovative rate designs and support for more stringent appliance efficiency standards and building

[21] AGA, *Natural Gas Rate Roundup*, May 2009, p. 3.

Figure 2 Current LRAMs by State



codes. The Washington Utilities Commission stated in its 1991 approval of a revenue decoupling plan for Puget Sound Power & Light that "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."[22]

High administrative costs help to explain why LRAMs are generally applied only to conventional DSM programs. This greatly limits the benefits that can result from LRAMs. The throughput-related disincentive will not be removed for numerous initiatives that can foster DSM. Utilities can be rewarded for load savings from DSM programs and still experience and benefit from rising average use. Another problem with LRAMs is that the dollars riding on the lost margin calculations can become quite large as the effects of DSM programs accumulate.

[22] Washington Utility and Transportation Commission, *3rd Supplemental Order* in Docket UE-901184-P p. 9.

5. Fixed/Variable Rate Designs

5.1. Fixed/Variable Basics

Fixed/variable pricing is an approach to rate design that controls the recovery through variable charges of costs that are fixed, in the *short* run, with respect to system use. A greater proportion of fixed costs are recovered through fixed charges such as customer charges or reservation charges that vary with *expected* future usage (e.g., peak demand). This means that customers pay a substantial fixed monthly charge for service regardless of their usage and cannot reduce that portion of their distribution bills with lower usage. *Straight* fixed/variable ("SFV") rate designs recover *all* fixed costs through fixed charges. A pricing system involving higher fixed charges that nonetheless does not recover all fixed costs through fixed charges is sometimes called "modified fixed variable" ("MFV") pricing.

5.2. Fixed/Variable Precedents

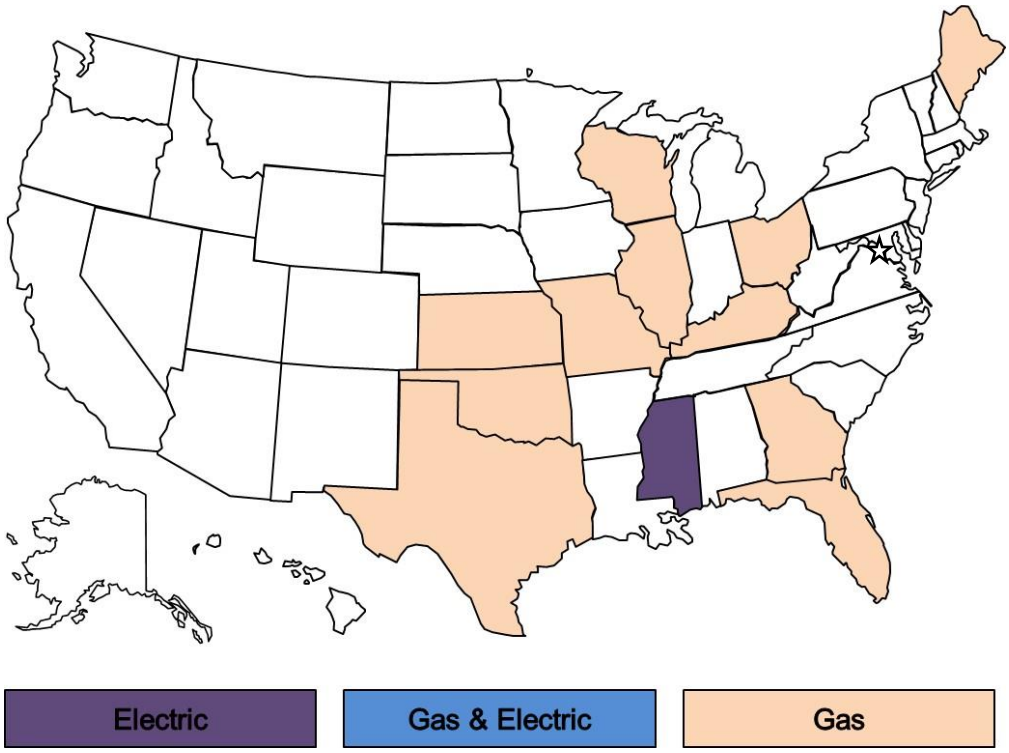
SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Current precedents for fixed/variable pricing in retail ratemaking are shown below in Figure 3. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida and Oklahoma have fixed charges that vary in some fashion with long-term consumption patterns.

5.3. Pros and Cons

Although straight fixed/variable pricing can remove the throughput-related disincentive for a wide range of utility DSM initiatives. The various disadvantages of fixed/variable pricing have prompted the NRDC to oppose it in many proceedings. The impact on revenue growth is similar to that of revenue-per-customer decoupling. Base rate revenue grows between rate cases at roughly the pace of customer growth. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing than with legacy rate designs so that rate cases are less frequent even if the decline is largely driven by external forces.[23] This helps to explain the popularity of fixed/variable pricing for gas distributors. These outcomes are achieved with stable rates. Administrative cost is low since it requires neither decoupling true-ups nor load impact calculations.

[23] Base revenue grows more slowly than under conventional rate designs if average use is rising.

Figure 3 Fixed/Variable Pricing Precedents by State



A salient disadvantage of fixed/variable pricing is the restrictions that it places on rate design. Rate design has an important impact on customer incentives for DSM because it affects the payback period on investments (e.g., those for better insulation) that these initiatives involve. DSM is generally encouraged by high usage charges. Critics of fixed/variable pricing also argue that usage charges are needed to communicate to customers the long-run cost of coincident peak demand and/or make up for any failure of energy commodity prices to reflect the marginal environmental cost of energy production and consumption.

Fixed/variable pricing can also produce sharp increases in bills for low income and other small-volume customers. Commissions committed to the principle of rate-change gradualism are likely to phase in higher customer charges gradually. Full straight fixed/variable pricing may never be implemented. In such cases, the (gross) benefits of fixed/variable pricing will be considerably less than those achieved by revenue decoupling.

6. Tracking of DSM Expenses

Relaxation of the revenue-usage link through such means as revenue decoupling creates little or no positive incentive for utilities to reduce the costs of their operations. We have seen that utilities

usually have muted incentives to contain tracked costs and an incentive to grow rate base. Tracker treatment for utility DSM expenses removes the disincentive utilities have to spend money on DSM between rate cases. It thereby helps to tip the balance of incentives to embrace DSM. Tracker treatment also reduces utility attrition when DSM programs are growing rapidly. Most US energy utilities have tracker treatment for their DSM expenses today.

7. DSM Performance Incentive Mechanisms

7.1. The Basic Idea

Performance metrics are quantitative indicators of the extent to which a utility is producing results that matter to customers and other stakeholders.[24] Target (aka "benchmark") values are usually established for some metrics in a system. Performance can then be measured by comparing a utility's values for these metrics to the targets.

Quantitative performance appraisals using metrics and targets are sometimes used in ratemaking. A targeted performance incentive mechanism ("PIM") links a utility's revenue mechanically to its performance as measured using metrics and targets. PIMs can strengthen performance incentives by providing awards and/or penalties.[25] This is a popular form of performance-based regulation.

Demand-side management metrics are used to evaluate the performance of utilities in encouraging DSM. We have noted that DSM initiatives can reduce customer bills, but that they may not be aggressively embraced by utilities under traditional regulation. Additionally, DSM programs can be costly, and regulators and stakeholder groups have keen interest in their cost effectiveness. Performance incentive mechanisms encourage utilities to embrace DSM as a cost management tool. Such PIMs can help level the playing field between DSM measures and supply-side investments, focus managerial attention on DSM initiatives, and change corporate culture.[26] They can encourage cost-effective DSM programs, and simplify oversight of the prudence of DSM investments.

DSM can reduce the costs and adverse externalities of utilities by reducing their loads. While lower costs are the ultimate goal of DSM, the loads themselves have typically been the focus of DSM

[24] These metrics are sometimes called key performance indicators. The British term for results is "outputs."

[25] Results for key performance metrics may be summarized in scorecards.

[26] For examples of the effects that DSM PIMs can have on utility planning and corporate culture, see p. 16 of *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency* (Hayes, S., Nadel, S., Kushler, M., & York, D., American Council for an Energy-Efficient Economy, Report Number U111, 2011), and section 2.6 of *Aligning Utility Incentives with Investment in Energy Efficiency* (National Action Plan for Energy Efficiency, prepared by Val R. Jensen, ICF International, 2007).

performance metrics used in PIMs. Delivery volumes and peak load are monitored, often by customer class.[27]

Load savings can be estimated using engineering models, off-the-shelf estimates of typical savings (aka "deemed savings"), or statistical analysis of customer billing data. Efforts are also commonly made to verify savings following program implementation (e.g., via site visits). Even with high-quality data, however, reliably estimating savings can be challenging due to several factors. These include free riders (customers who would have implemented the efficiency measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient).

The difficulty of measuring load savings varies by program. Simplicity is an important goal, but this can encourage a focus of metrics and associated PIMs on programs that have more measurable impacts. Other DSM initiatives that are equally or more cost effective may be neglected. These initiatives may include changes in rate designs, cooperation with third party vendors of energy services, campaigns to tighten state and federal building codes and appliance efficiency standards, and other efforts to transform energy service markets. There is nonetheless increasing effort to monitor DSM progress in areas where savings are hard to measure, even if no financial incentives are attached. Potential metrics include the market share of efficient technologies, the number of established third-party vendors of efficiency services, and trends in delivery volumes adjusted for known drivers such as local weather and personal income.

Demand-side management PIMs typically involve awards but no penalties. Awards may be granted for all load savings, but are typically contingent on attainment of a threshold level of savings which may be higher or lower than the target. Awards are sometimes capped.

Compensation for load savings can take several forms.

Shared savings. This approach grants the utility a share of the estimated net benefits that result from a DSM initiative. Net benefits are the difference between benefits and costs, so this approach encourages utilities to choose more cost-effective programs and manage them more efficiently. However, the estimation of net benefits can be a complex and controversial issue in regulatory proceedings. This issue is discussed further below.

[27] The percentage of customers participating in DSM programs is another metric of interest.

Bonus. Another possibility is to compensate the utility at a set rate for each unit of load savings achieved (or for each unit of another desired outcome). The bonus rate may differ for different kinds of projects in the utility's portfolio.

Management fees. This alternative grants the utility an incentive equal to a specific share of program expenditures. Under this approach, the incentive calculation depends on the costs incurred (specifically, expenditures by the utility) but not on the benefits achieved. The utility is rewarded for spending money. However, its simplicity makes it an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), but its ease of administration has encouraged its use for other types of DSM programs as well. For example, in California a complex shared-savings PIM was recently replaced with a PIM based on management fees.[28]

Lump sum. This option involves a lump-sum payment for achieving a specified level of load savings. Unlike the three approaches just discussed, the size of the incentive payment does not vary with either the costs or benefits, but instead is of a fixed size. A lump-sum reward is conceptually simple. However, the utility only benefits from crossing a performance threshold. It is not rewarded for pursuing cost-effective gains above the threshold, nor discouraged from implementing unduly costly programs below the threshold.

Amortization. This approach involves amortizing DSM expenditures. A premium is often added to the ROE that is applied to these expenditures. This premium may be contingent on achieving certain performance goals. The return may be earned immediately through a tracker or accumulate in a regulatory asset. As is the case with management fees, the size of the incentive payment is determined by costs (i.e., utility expenditures) rather than benefits.

7.2. Precedents for DSM Performance Incentive Mechanisms

The 2015 scorecard of the American Council for an Energy Efficient Economy ("ACEEE") indicates that demand-side management PIMs are fairly common for US electric utilities.[29] Figures 4a and 4b indicate states that have implemented these PIMs, and also revenue decoupling. On the electric side, it can be seen that 27 jurisdictions had some form of demand-side management PIM, including

[28] California Public Utilities Commission (2013). Decision 13-09-023, Rulemaking 12-01-005.

[29] American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015.

Figure 4a DSM Performance Incentive Mechanisms: Electric

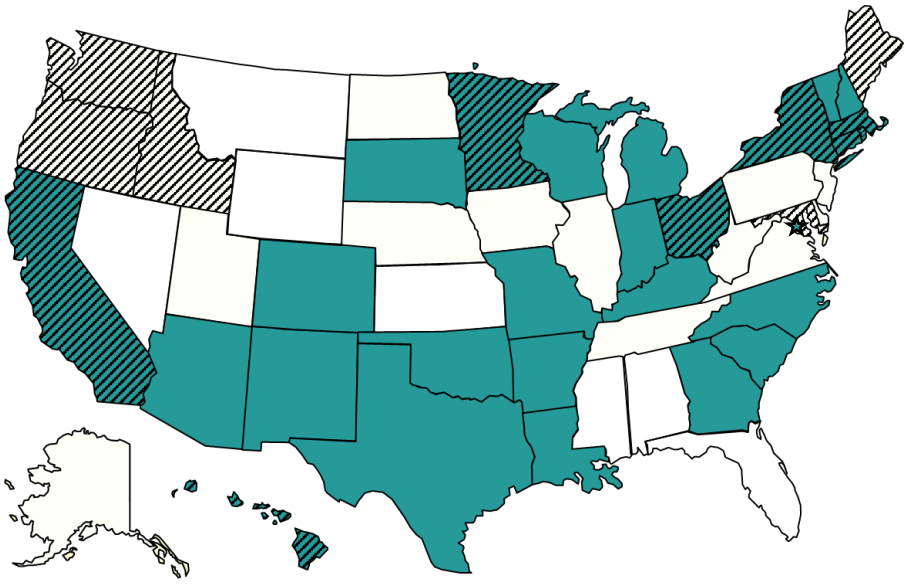


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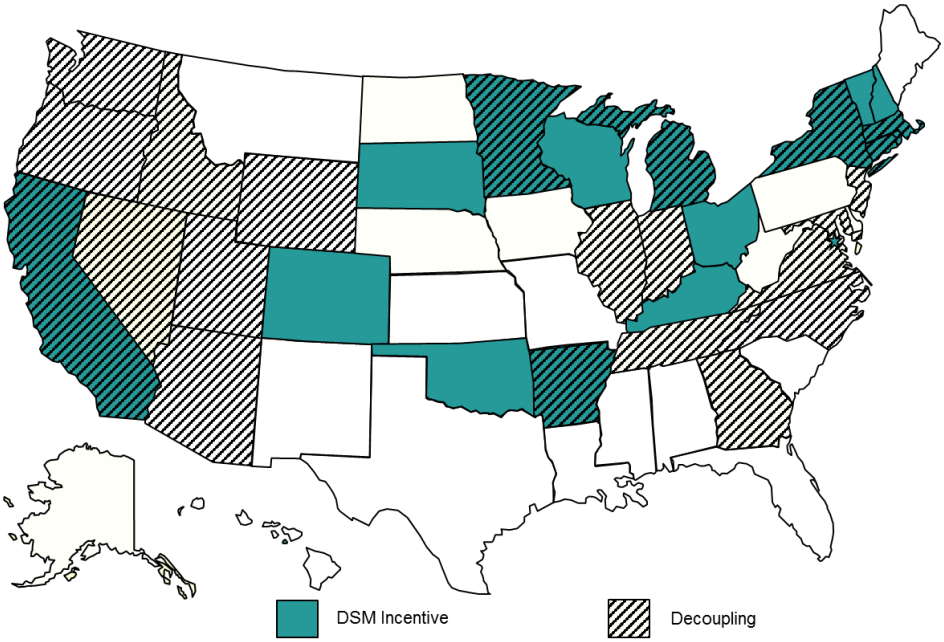
Figure 4b DSM Performance Incentive Mechanisms: Gas



REFERENCES

Pacific Economics Group Research and American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015.

Pennsylvania's neighboring states of New York and Ohio. At least ten jurisdictions that had implemented demand-side management PIMs had also adopted revenue decoupling for the same industry. For example, Minnesota recently approved revenue decoupling for Northern States Power and revised but retained its demand-side management PIM. Some of the states that have revenue decoupling but no demand-side management PIMs have an independent DSM program administrator. On the gas side, the ACEEE notes demand-side management PIMs in seventeen jurisdictions, including once again New York and Ohio. Eight of these states also have decoupling.

It is also notable that PIMs for demand-side management have often been used by utilities operating under multiyear rate plans. California and New York are examples of states where this combination is used for both gas and electric utilities.

Among demand-side management PIMs, those focused on energy efficiency are the most common, and some states have decades of experience with them. Some existing PIMs also address demand response.

Shared savings mechanisms have been the most popular PIM compensation approach. However, management fees are also widely used, and other types of PIMs are not uncommon. In some cases, more than one PIM type has been combined within a single incentive package (e.g., shared savings for programs with quantifiable benefits, management fees for education and marketing programs).

Most demand-side management PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, such as those where transmission and distribution capex will otherwise be needed in the near future to replace aging assets or accommodate growing load. Consolidated Edison of New York's Brooklyn Queens Demand Management Program provides an example of a geographically targeted PIM.

Peak-Load Management

There is growing interest in metrics and PIMs for peak-load management for several reasons.

- Peak load is more important than volume as a driver of power distribution and transmission cost.
- Demand for power distribution services can be quite peaked on circuits that chiefly serve residential and commercial customers. Peakedness can be exacerbated by high penetration of distributed solar generation.

- Most power distributors purchase power in managed markets for the merchant services (e.g., "standard offer" services) which they provide. Prices in these markets are volatile. Low prices typically occur at night when demand is weakest, while highs occur in the early evening hours of business days when demand is stronger and any solar power supplies are diminishing. Shifting demand to low-price periods can substantially reduce purchased-power costs.
- Many distributors are engaged in accelerated modernization programs that involve replacement of substations and other load-related capacity. The ratemaking treatment of this capex often involves frequent rate cases, conventional cost trackers, or other mechanisms that can weaken cost containment incentives. Peak-load management PIMs encourage utilities to embrace DSM tools that reduce the need for such capex.
- With AMI increasingly widespread, there are expanded opportunities to reduce load peakedness. Regulators are showing increased interest in using AMI more aggressively for this purpose.[30]
- With the cost of distributed storage falling, the responsiveness of customers to peak-load management initiatives may increase.

Interest in peak-load management will be greater wherever it can produce material cost savings due to increasing load peakedness, system expansion, accelerated replacement capex, and marked volatility in bulk power prices.

Regulators are interested to know how much the capabilities of AMI to encourage better peak-load management are being utilized. One concern of regulators is the level of customer engagement. Customer engagement metrics that have been used in regulation are detailed below.

- Number (or %) of customers using utility web portal to access energy usage information and/or enroll in utility information programs
- Number (or %) of customers who have authorized utility to provide a third party with energy usage data
- Number (or %) of AMI customers with registered Home Area Network
- Number (or %) of customers enrolled in demand-response or dynamic-pricing programs

[30] See, for example, "California Regulators Approve Major Overhaul of Residential Electric Rate," *SNL Electric Utility Report*, 13 July 2015 and "California Mandates TOU Pricing for Residential Customers," *PUR Utility Regulatory News,"* Letter #4229, 17 July 2015.

PIMs for peak-load savings are likely to be based on the kW of peak load saved. Calculation of such savings can be complicated since peak loads are sensitive to volatile external business conditions such as the temperature on the hottest summer days. Estimates of peak-load savings may, however, be available from program evaluations or demand-side bids in bulk power markets. Permitting utilities to keep some or all of the revenue obtained from demand-side bids that they make is an alternative to a peak-load reduction PIM. Regulators may also be interested in measures of load peakedness whether or not they provide the basis for PIMs.

7.3. Pros and Cons of Demand-Side Management PIMs

PIMs offer both advantages and disadvantages as a way to incentivize utilities to implement DSM programs. These PIMs can complement measures to reduce the throughput incentive by providing a positive incentive to use DSM for cost containment. Another advantage is that in some jurisdictions PIMs may be more feasible to implement than alternative means of encouraging DSM, such as multiyear rate plans or revenue decoupling.

Demand-side management PIMs can also help offset the throughput-related disincentive for embracing DSM. However, we have noted that other tools, such as revenue decoupling, can be used to relax the revenue-usage link and have certain advantages. Where these tools are employed, deploying demand-side management PIMs in addition (e.g., as a complement to decoupling) provide positive incentives to reduce costs of fuel, purchased power, and load-related capex, and to mitigate adverse environmental externalities.

Demand-side management PIMs also have some drawbacks. Like LRAMs, they can involve complex calculations that invite controversy in regulatory proceedings. Moreover, the rewards granted to utilities for load savings can sometimes become sizable over the years. In addition, awards offered by a PIM may be inadequate to compensate the utility for lost capex opportunities. Finally, by motivating utilities to improve their performance in relation to specific programs and metrics, PIMs may lead to a deterioration in other aspects of DSM performance that are not measured. This speaks to the need for demand-side management PIMs with a broad focus. This is a concern of Department of Public Service Staff in New York's Reforming the Energy Vision ("REV") proceeding.

8. Multiyear Rate Plans

8.1. The Basic Idea

Multiyear rate plans ("MRPs") are the most common approach to PBR around the world. The basic idea is to compensate a utility for its services for several years with revenue that, while reflective of cost pressures, does not closely track the utility's own cost of service. MRPs utilize two tools to relax the link between a utility's own cost and its revenue:

1. A moratorium is imposed on general rate cases that typically lasts two to four years.
2. Between rate cases, an attrition relief mechanism ("ARM") automatically adjusts rates or the revenue requirement for changing business conditions (e.g., inflation and customer growth) without linking the relief to the utility's own cost growth. Methodologies for achieving this include cost forecasting and inflation and productivity indexing. Some MRPs feature rate freezes.

The combination of a rate case moratorium and the ARM approach to rate escalation can strengthen cost containment incentives and permit an efficient utility to realize its target rate of return on equity ("ROE") despite a material reduction in regulatory cost. MRPs typically address some costs separately from ARMs using trackers. Tracker treatment is useful for costs that are difficult to address using ARMs.

Some MRPs have earnings sharing mechanisms which share surplus and/or deficit earnings between utilities and customers. These earnings result when the ROE deviates from its commission-approved target. Off-ramp mechanisms may permit suspension of a plan under pre-specified outcomes such as persistently extreme ROEs.

Most MRPs also include PIMs. These have in the past been used chiefly to balance incentives for cost containment with incentives to pursue other goals that matter to customers and the public. PIMs used in MRPs for electric utilities have been especially common for energy efficiency, reliability and customer service (e.g., telephone response time, timeliness in meeting scheduled appointments and connections, and the accuracy of invoices). In the future, MRPs are likely to include PIMs that address new concerns such as peak-load management and the quality of connections and other services offered to distributed generation customers.

8.2. MRP Precedents

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated Figures 5a and 5b. In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have recently been adopted by well-known vertically integrated electric utilities in Florida, North Dakota, and Virginia. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

8.3. Advantages of MRPs for Encouraging DSM

MRPs can improve utility incentives to embrace DSM if properly designed. Their chief advantage is the general incentive they can provide to slow rate base growth. Since DSM can be an effective tool for reducing rate base growth, utilities have a stronger incentive to use it. For example, if a utility uses DSM to reduce the need for substation capex, it can keep some of the cost savings for several years.

MRPs can also incorporate mechanisms to weaken the short-term link between revenue and sales, such as revenue decoupling. When an MRP features revenue decoupling, the ARM escalates allowed revenue and is basically a broad-based revenue adjustment mechanism, as described in Section 3. Utilities in California and Hawaii, which have experienced the highest levels of distributed solar generation penetration in the United States, operate under MRPs with revenue regulation.[31] The "RIIO" approach to utility regulation in Britain combines a multiyear rate plan and revenue decoupling.[32]

A utility's incentive to embrace DSM under an MRP can be further strengthened by adding a demand-side management PIM and tracker treatment of DER-related expenditures. The combination of an MRP, revenue decoupling, performance incentive mechanisms to encourage efficient DSM, and the tracking of DSM-related costs can provide four "legs" for the DSM "stool."

[31] Solar generation is also encouraged in these states by other conditions, including strong sunlight.

[32] The acronym RIIO stands for Revenue = Incentives + Innovation + Outputs

Figure 5a Recent US Multiyear Rate Plan Precedents by State

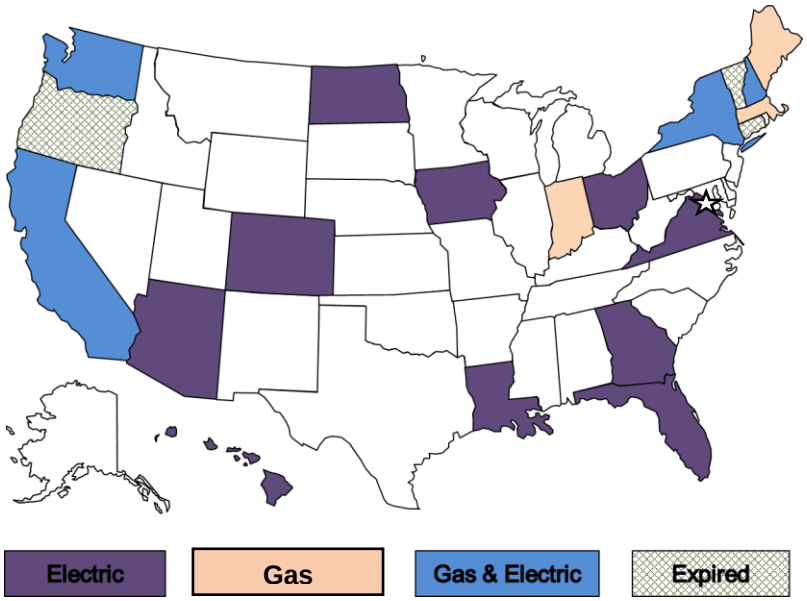
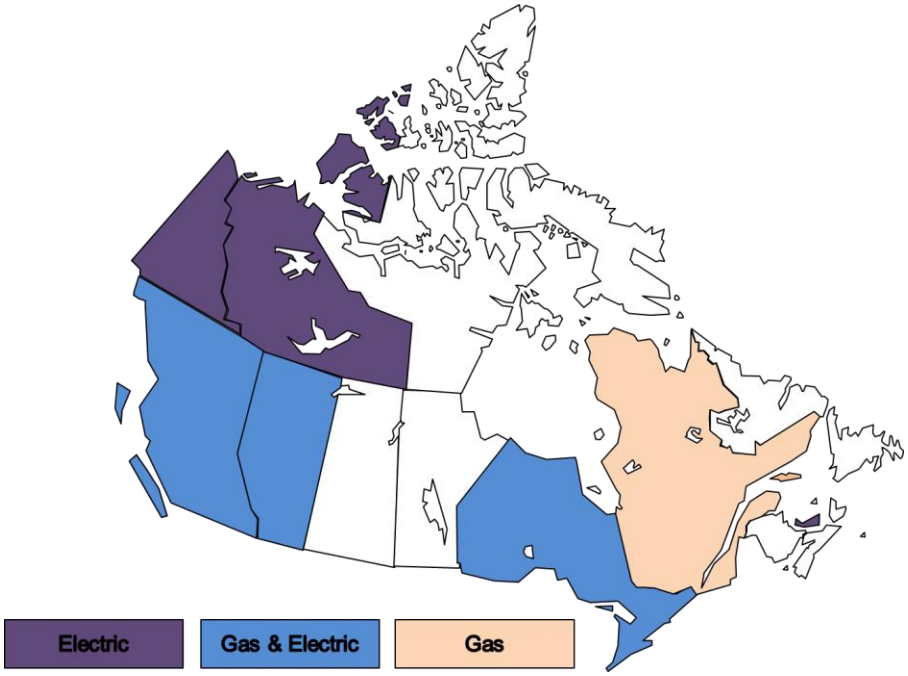


Figure 5b Recent Canadian Multiyear Rate Plan Precedents by Province



9. Conclusion

Using gas and electric power more efficiently is the cheapest and cleanest way to meet America's energy needs. There is enormous potential to save money, create jobs, and reduce pollution by making use of the grid less peaked and by improving buildings, processes, and energy-using devices. Demand-side management programs are needed to overcome the persistent market barriers that prevent households, businesses, and industry from taking advantage of these opportunities. Pennsylvania energy distributors are strategically placed to undertake many of these programs. However, reforms in the existing regulatory system are needed for distributors to pursue DSM aggressively.

Removing the throughput incentive can play a key role in encouraging utilities to embrace DSM. Revenue decoupling is the preferred means of accomplishing this, for several reasons. The throughput-related disincentive is reduced or eliminated for the full range of utility initiatives that can encourage DSM. This is accomplished without the complicated benefit calculations or restrictive rate designs that alternative methods require. Commissions can continue their traditional role of approving rate designs for standard tariffs which balance diverse considerations. These considerations should include the welfare of low-use customers and the long-term impact that system use has on transmission and distribution capital spending and other costs. Alternative approaches to relaxing the revenue/usage link have shortcomings that severely limit their application and reduce their benefits.

Decoupling also has desirable side effects. Full decoupling, which encourages rate designs that foster DSM, also reduces the risk of demand volatility and declining average use from diverse sources. The revenue adjustment mechanisms that we have seen are an integral component of decoupling systems can provide responsible, automatic revenue escalation for changing business conditions. The need for rate cases can be reduced when average use is declining. An array of designs are available for revenue adjustment mechanisms, from the conservative revenue per customer approach that is popular with gas distributors to broad-based designs that provide the basis for multiyear rate plans.

The diverse benefits of decoupling help to explain why it is widely used even where declining average use results chiefly from external sources rather than utility DSM programs. Several states use revenue decoupling for energy utilities even though DSM is chiefly undertaken by third parties.

Despite its many advantages, revenue decoupling cannot by itself provide the incentives needed for utilities to fully embrace DSM as a cost management tool. Environmental impacts of utility operations are largely external, and cost trackers mute incentives to contain purchased power and other

costs. DSM can diminish opportunities for utilities to grow rate base. Utilities therefore need positive incentives to embrace DSM.

Performance incentive mechanisms are used in many states to reward utilities for their DSM programs. The challenge today is to design demand side management PIMs that encourage a wide range of utility initiatives and transform markets. Multiyear rate plans can further strengthen cost containment incentives and the willingness of utilities to embrace DSM. Tracking utility DSM expenses can also encourage utilities to choose DSM as a cost containment strategy.

10. Appendix

10.1. About the Authors

Mark Newton Lowry is the President of PEG Research LLC, a company in the Pacific Economics Group consortium that is prominent in the field of alternative regulation. He has almost thirty years of experience as an industry economist. Decoupling, PBR, and other forms of Altreg have been his chief professional focus for twenty five years. He has testified dozens of times on Altreg issues. Work for a mix of well-known utilities, trade associations, regulatory commissions, environmental organizations, and other clients has earned him an unusual reputation for objectivity and dedication to good regulation.

Before joining PEG, he was for several years an Assistant Professor of Mineral Economics at the University Park campus of the Pennsylvania State University. He has also worked as a Vice President at Christensen Associates and as a visiting professor at l'Ecole des Hautes Etudes Commerciales in Montreal. Dr. Lowry can serve clients in French and Spanish as well as English. His resume includes an extensive list of publications and public appearances. A Cleveland, OH native, he attended Princeton and holds a Ph.D. in Applied Economics from the University of Wisconsin.

Kaja Rebane is a Level II Economist at PEG Research. She has three years of experience as a professional energy economist. Kaja holds an undergraduate degree from Stanford, as well as Master's degrees in Applied Economics and Land Resources and a certificate in Energy Analysis and Policy from the University of Wisconsin. A Las Vegas native, she is pursuing a Ph.D. in Environment and Resources at the University of Wisconsin.

10.2. Precedent Tables

Table A1 lists current precedents in the US and Canada for gas and electric revenue decoupling mechanisms.

Table A1

Current Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			United States		
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2016	Stairstep	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-open	Indexing through 2015, No RAM thereafter	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2012-open	Stairstep through 2015, No RAM thereafter	Decision 13-05-010
CA	Southern California Edison	Electric	2015-2017	Hybrid	Decision 15-11-021
CA	Southern California Gas	Gas	2012-open	Stairstep through 2015, No RAM thereafter	Decision 13-05-010
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Avista	Electric & Gas	2016-2018	Customers	Cases AVU-E-15-05, AVU-G-15-01
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IL	Ameren Illinois	Gas	2016-open	No RAM	Case 15-0142
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	NewEngland Gas	Gas	2011-open	Customers	DPU 10-114
MA	Nstar Gas	Gas	2016-open	Customers	DPU 14-150
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999

Table A1 (cont'd)

Current Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
United States (cont'd)					
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-2016	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-open	Revenue per Customer Stairstep through 2014, Customers After 2014	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2010-open	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0715
NY	New York State Electric & Gas	Electric	2010-open	Stairstep through 2013, No RAM thereafter	Case 09-G-0716
NY	Niagara Mohawk	Gas	2013-2016	Optional Revenue per Customer Stairstep	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2016	Optional Stairstep	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2010-open	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0717
NY	Rochester Gas & Electric	Electric	2010-open	Stairstep through 2013, No RAM thereafter	Case 09-G-0718
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Cascade Natural Gas	Gas	2016-2019	Customers	Order 15-412
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2016-2018	Customers	Case PUE-2015-00072
VA	Virginia Natural Gas	Gas	2013-2016	Customers	Case PUE-2012-00118
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202

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