American Council for an Energy-Efficient Economy

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May 31, 2017

Chairman Brown
Vice Chairman Place
Commissioner Coleman
Commissioner Powelson
Commissioner Sweet
Pennsylvania Public Utilities Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Alternative Ratemaking Methodologies, Docket No. M-2015-2518883.

Dear Chairman Brown and fellow Commissioners:

The American Council for an Energy-Efficient Economy (ACEEE) welcomes the opportunity to provide written comments on the proceeding on alterative ratemaking methodologies. ACEEE appreciates the Commission's interest in exploring complicated issues associated with alternative ratemaking. ACEEE also appreciates the Commission's leadership in implementation and support of the Act 129 energy efficiency programs. Energy efficiency is a valuable low-cost energy resource which provides many benefits to residents and business in the Commonwealth.

Our comments focus on issues related to alterative ratemaking and the Commonwealth's energy efficiency goals. Our research demonstrates energy efficiency programs are generally the least cost resource available to electric utilities nationally.[1] Further research also demonstrates the substantial value of energy efficiency to reduce system costs and defer the need to invest in costly distribution and transmission infrastructure.[2] Well-designed electric rates can be a useful complementary policy tool to encourage energy efficiency. However, poorly designed rates such as high monthly customer charges can discourage customer investments in energy efficiency and increase overall consumption, leading to unneeded costly utility investments.

Our comments focus on seven primary recommendations. We recommend the PUC:

1. Approve full revenue decoupling for gas and electric utilities in Pennsylvania. This policy balances the interests of utilities and customers by ensuring cost recovery while still promoting customer investment in cost effective energy efficiency.

2. Carefully consider the impact of alternative rate designs on the implementation of other state policy goals, such as the energy efficiency targets outlined in Act 129.

[1] Molina, M. 2014. *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.* American Council for an Energy-Efficient Economy. aceee.org/research-report/u1402.

[2] Neme, C. and J. Grevatt. 2016. *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.* Energy Futures Group, prepared for the Northeast Energy Efficiency Partnerships. neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

3. Reject increases to monthly customer charges beyond those determined using the basic customer method. The basic customer method is cost based, equitable to all customers, and provides price signals to customers to use energy efficiently.

4. Reject demand charges for residential customers. Residential demand charges are not cost based when structured using coincident or noncoincident peak costs. They are also not well understood by residential customers and produce a lower peak demand reduction than other rate approaches, like time of use rates.

5. Move towards expansion of time of use rates for all residential customers.

6. Approve standby rates that follow best practices described herein.

7. Adopt performance incentives for utilities to drive greater performance in energy efficiency programs.

I. FULL REVENUE DECOUPLING

Adoption of full revenue decoupling has increased in recent years, and currently electric utilities in 15 states and the District of Columbia and gas utilities in 22 states use this mechanism.[3] ACEEE fully supports the use of full revenue decoupling to ensure utilities are able to recover authorized costs.[4] Full revenue decoupling also effectively balances risk between a utility and its customers. Utilities are protected from under recovery of revenues while customers are protected from over recovery. Revenue decoupling is a mechanism that alleviates utility concerns of revenue erosion and cost recovery.

One primary concern of decoupling mechanisms has been rate impacts to customers. A comprehensive study on revenue decoupling evaluated rate impacts for decoupling mechanisms nationally.[5] This research shows that rate impacts have been minimal. Morgan (2012) examined a set of 1269 rate adjustments made due to decoupling mechanisms since 2005. She found that the vast majority (64%) of such adjustments have been only plus or minus 2% of retail rates. This translates to customer surcharges or credits of $2.30 per month for the average electric customer and about $1.40 per month for the average natural gas customer. About 80% of all such adjustments are within the range of plus or minus 3%. In short, decoupling does generally not lead to wide rate swings. Of all the adjustments included in Morgan's research, 63% were surcharges and 37% were refunds. She concludes that there is no pattern of either rate increases or decreases.

In the Alternative Ratemaking Methodology Tentative Order issued March 2, 2017, the PUC requested information on how specific alternative rate methodologies could be implemented. The implementation of full revenue decoupling varies by jurisdiction and utility. The Regulatory Assistance

[3] Berg, W. et al. 2016. "The 2016 State Energy Efficiency Scorecard." ACEEE. http://aceee.org/research-report/u1606.

[4] We define full revenue decoupling as a decoupling mechanism which adjusts utility revenues on a periodic basis to ensure a utility does not over or under recovery commission authorized revenues. We do not include lost revenue, weather, or other partial decoupling mechanisms in this definition.

[5] Morgan, P. 2012. "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Graceful Systems LLC. November. aceee.org/files/pdf/collaborative-reports/decade-of-decoupling.pdf.

Project has published several papers which help states determine how to best design a full revenue decoupling mechanism that meets a specific state's policy goals. We have attached this paper at Appendix A of these comments. It provides practical guidance on how the mechanism could be structured.

While we support the implementation of full revenue decoupling, we recommend the PUC reject any proposal for a lost revenue adjustment mechanism (LRAM). A LRAM is problematic for several reasons. First, it does not eliminate the throughput incentive (the incentive for utilities to increase sales to increase revenue). Instead, it incentivizes utilities to encourage increased consumption because there is no reconciliation of revenues based on sales, as there would be with a full revenue decoupling policy. Instead utilities are able to recover lost revenue associated with energy efficiency programs, regardless of sales. This introduces the second significant problem associated with this policy, it allows utilities an opportunity to over earn revenue requirements. Full revenue decoupling eliminates the throughput incentive and eliminates the opportunity for a utility to earn revenue beyond the PUC authorized revenue requirement.

Recommendation: Approve full revenue decoupling for gas and electric utilities in Pennsylvania. This policy balances the interests of utilities and customers by ensuring cost recovery while still promoting customer investment of cost effective energy efficiency. We also recommend the rejection of any LRAM policy because it does not eliminate the throughput incentive and allows an opportunity for utilities to over earn PUC authorized revenue requirements.

II. CONSIDERATION OF OTHER STATE POLICY GOALS

Certain rate design approaches are in direct conflict with the energy efficiency and conservation goals in Act 129. There are two primary ways in which poor rate design may compromise the Commonwealth's goal of reduction in overall consumption. First, rate options like high customer charges may actually increase consumption over time. This is because an increase in the customer charge requires a decrease in the volumetric rate, assuming no change in utility revenue. Customers respond to lower energy prices by increasing consumption. Many electricity pricing pilots document this response.[6] The increase in consumption brought on by the change in rate design is in direct conflict with the stated goals of Act 129.

Second, energy efficiency program payback periods are significantly altered by rate design. In a recent report, *Rate Design Matters: The Intersection of Energy Efficiency and Rate Design,* ACEEE examined the effect that changes in revenue neutral rate design have on payback periods for 14 energy efficiency programs in the service territory of Arizona Public Service (APS). The analysis showed moving from rate design with lower customer charges and tiered rates to high customer charges and demand charges increased the payback period by 30% to 60%, depending on the rate design. This may reduce customer willingness to engage in energy efficiency programs, potentially making it more challenging to meet the goals of Act 129. We have attached this report as Appendix B. The report shows the results for all 14 measures.

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[6] *See* the Consumer Behavior Studies conducted under the Department of Energy's Smart Grid pricing pilots for examples of this measured effect. smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html.

Recommendation: Carefully consider the impact of alternative rate designs on the implementation of other state policy goals, such as the energy efficiency targets outlined in Act 129.

III. HIGHER CUSTOMER CHARGES

Many utilities in Pennsylvania and elsewhere in recent years have requested increased customer charges under the premise that costs that could be considered utility fixed costs should be recovered in fixed charges. This logic in the context of ratemaking is flawed for several reasons. First, recovering utility costs in this way is not cost-based or rooted in cost causation. The cost to serve individual customers varies based on a number of factors. For example, urban customers cost less to serve than rural or suburban customers, and customers in multifamily buildings cost less to serve than those in single family homes. This method of cost recovery through fixed customer charges will substantially over collect costs from some users and under collect from others.

It is also important to consider the differences between short and long term fixed costs. Some costs which may be considered fixed in the short term are variable in the long term. Rate design focused on high fixed charges presents a price signal to customers that these costs are fixed in the long term and unavoidable. Some future costs, such as new generation and distribution system upgrades, are in fact variable and may be avoided.

Second, recovery of costs in this manner sends customers poor price signals leading to inefficient levels of consumption. Customers respond to price signals. Moving cost recovery from volumetric rates to fixed charges will increase consumption over time because customers do not receive a price signal that their usage creates capacity costs for a utility.[7] This in turn will ultimately lead to unnecessary increases in utility infrastructure investment costs and higher rates for all customers.

Third, this type of rate design does not align with generally accepted principles of rate design, specifically the principle of efficiency in rates discouraging wasteful use of service. This criteria is one of three primary principles outlined by Professor James Bonbright in *Principles of Public Utility Rates*. In the text, Professor Bonbright recognized the importance of setting rates that avoid the wasteful use of public utility resources. While this text was published over 50 years ago, it still guides ratemaking decisions today. The need to discourage wasteful use of resources is also just as important today to help the United States address climate change and to keep energy affordable.

Recommendation: The Pennsylvania Public Utilities Commission should reject utility proposals for higher customer charges and implement a policy of only accepting the basic customer method to determine this charge. This method is tested, cost based, equitable, and aligns with other state policy goals of promoting energy efficiency.

IV. RESIDENTIAL DEMAND CHARGES

Demand charges have not been historically used to collect revenues from residential customers. While there are a few electric utilities with optional demand charge rates, very little data exists on how

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[7] *See* Kihm, S. 2015. "Economic Concerns About High Fixed Charge Pricing for Electric Service." americaspowerplan.com/wp-content/uploads/2014/10/Economic-analysis-of-high-fixed-charges.pdf.

customers respond to demand charges. In a recently published paper on rate design, the Rocky Mountain Institute reviewed the experience with residential customers on demand charges.[8] The research concluded that the impact of demand charges on peak demand and overall consumption reduction are unclear at this time and require more research. Our review of pricing studies of several rate design options show demand charges to have a smaller peak demand reduction benefit than other rate design types.[9]

The cost basis for residential demand charges is also highly questionable. Distribution system infrastructure is not sized to meet the utility system-wide peak or a customer's individual peak (in most cases). Instead, the infrastructure is sized to meet a diverse set of individual customer loads, which may or may not align with the system peak. Therefore, to assess a demand change on a residential customer based on coincident peak would not align with the costs driving system peak. A noncoincident peak demand charge is also not cost based. A noncoincident peak demand charge may over recover costs associated with that specific investment because customers sharing the capacity likely have individual peak demands at different times of the day; as a result, the sum of their noncoincident demands might exceed actual total capacity.

A recent report by several rate design experts on assessing demand charges on small customers (residential and small general service) found that demand charges are not cost based on coincident and noncoincident peak scenarios, provide little actionable information in terms of a price signal, and are difficult to understand. We have attached this report at Appendix C to our comments.

Recommendation: The PUC should reject any proposals for mandatory residential demand charges. These charges are not cost based, have lower peak demand reductions than other rate options, and little evidence exists on how customers respond to residential demand charges.

V. TIME OF USE RATES

Time of use rates are growing in popularity as a rate design option that better aligns utility costs with rates and drives specific policy outcomes, such as reduced peak demand. Some states, including Arizona and California, are beginning to transition residential customers to default time of use rates to address issues related to rooftop solar proliferation and utility cost recovery concerns.[10,11] Time of use rates are well understood by customers and provide substantial demand reduction benefits.[12] Time of use rates also match cost causation as recovery of costs is linked to the time of day, week, and year when system costs are incurred to serve demand.

Recommendation: The PUC should move towards expansion of time of use rates for all residential customers.

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[8] *See* Rocky Mountain Institute. 2016. "A Review of Alternative Rate Designs Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers." rmi.org/Content/Files/alternative_rate_designs.pdf.

[9] *See* Baatz, B. 2017. "Rate Design Matters: The Intersection of Rate Design and Energy Efficiency." ACEEE. http://aceee.org/research-report/u1703.

[10] *See* final order and decision issued August 18, 2016, UNS Electric, Docket No. E-04204A-15-0142. images.edocket.azcc.gov/docketpdf/0000172763.pdf.

[11] *See* Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations, "Decision on Residential Rate Reform"D.15-07-001 (July 13, 2015)

[12] *See* Faruqui, A., Hledik, R., and J. Palmer. 2012. "Time Varying and Dynamic Rate Design." Regulatory Assistance Project and The Brattle Group. raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

VI. STANDBY RATES

Under some rate structures, combined heat and power (CHP) customers are faced with confusing and often excessive charges for supplemental, standby and back-up electricity provided by their local utility, which can create a disincentive to invest in CHP as a distributed energy resource. Utility tariff structures for these services are a key condition for the economic viability of CHP projects. Rates that recover the majority of the cost of service in fixed charges or ratcheted demand charges significantly reduce the financial viability of a CHP project. In some cases, ratchets can remain in place for a year or more, which is generally viewed as detrimental to the deployment of CHP.

The appropriate level of standby rates has been the subject of debate between utilities and customers. Many of the prevailing tariff structures suffer from deficiencies and create barriers to greater CHP deployment. In a 2014 study, the Regulatory Assistance Project examined utility standby rates in five states, identified deficient designs, and made recommendations on how to improve rate designs that encourage the deployment of cost-effective CHP resources.[13] Additionally, a detailed review by the US DOE-sponsored Midwest Clean Energy Application Center of existing Iowa standby rates offers a clear analysis of how various rate structures impacts CHP projects, and suggests best practices.[14] We urge the Commission to consider these known best practices and ensure that utility tariffs represent these principles in good standby rate design.

Finally, CHP offers known reliability and resiliency benefits, particularly when it serves critical facilities such as hospitals, water treatment plants, and government operations facilities. In many cases when the grid goes down, CHP systems have been able to stay online and meet some of the additional need created by the grid failure. We recommend these benefits be considered in rate design. The ability of CHP systems to serve demand that local utilities are expected to serve should be reflected in any rate structure for CHP systems capable of black-start and island mode. When CHP customers are fairly charged for the grid services they actually receive or offer, this will send price signals that encourage investment in more efficient use of electricity and give customers an incentive to maximize the benefits of distributed generation.

Recommendation: The PUC should focus on the best practices outlined above to address the challenges associated with standby rates for customers utilizing CHP.

VII. PERFORMANCE INCENTIVES

ACEEE strongly supports the use of financial incentives to drive utility performance in energy efficiency programs. Performance incentives are a useful policy instrument that allow the PUC an opportunity to use financial rewards to meet specific policy goals, such as higher energy savings or seasonal peak demand reduction. ACEEE has published multiple studies on the differences in performance incentive approaches. We have attached our most recent study on this topic, *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency,* as Appendix D. As the report shows, performance incentives can be designed in many different ways.

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[13] See RAP's blog post and full report. Blog: raponline.org/news/standby-rates-for-combined-heat-and-power-need-a-fresh-look/. Full report: raponline.org/wp-content/uploads/2016/05/rap-standbyratesforchpsystems-2014-feb-18.pdf.

[14] See the full analysis of Iowa rates here: iowaeconomicdevelopment.com/userdocs/documents/ieda/Iowa-On-Site-Generation-Tariff-Barrier-Overview_April-20121.pdf#.

We recommend a careful approach to developing a performance incentive. Performance incentives should be linked to verified energy savings, not spending. Performance incentives should be set in conjunction with specific energy savings targets and based on tiers of performance, awarding utilities that surpass targets. Finally, performance incentives should be capped at a reasonable amount.

Recommendation: The PUC should adopt performance incentives for utilities to drive greater performance in energy efficiency programs.

Sincerely,

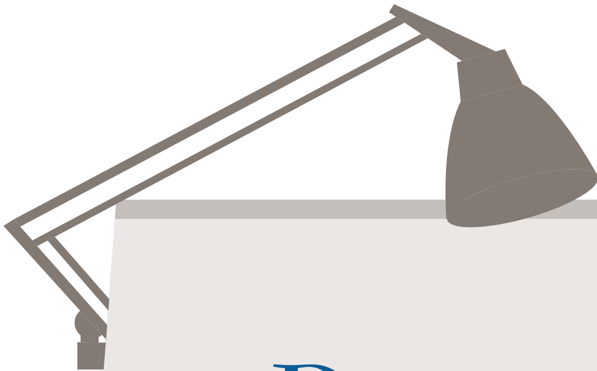
Brendon Baatz
Senior Manager, Utilities Program
American Council for an Energy-Efficient Economy

Appendix A

Decoupling Design: Customizing Revenue Regulation to Your State's Priorities

Regulatory Assistance Project, 2016

RAP® Energy solutions for a changing world



Decoupling Design: Customizing Revenue Regulation to Your State's Priorities

Authors

Janine Migden-Ostrander and Rich Sedano

Acknowledgments

This document was authored by RAP Principals Janine Migden-Ostrander and Rich Sedano, with input from RAP Senior Advisor Jim Lazar and RAP Principal Frederick Weston. External reviews and helpful input were provided by John Howatt of the National Consumer Law Center, Betty Watson of SolarCity, and Tim Woolf of Synapse Energy Economics. Each of these individuals provided insightful feedback at various stages of this report. Please note that the authors are ultimately solely responsible for the information presented and the conclusions drawn in the report. Internal review and project guidance was provided by Camille Kadoch, Jake Brown, Donna Brutkoski, Becky Wigg, and Deb Stetler.

How to Cite This Paper

Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities

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November 2016

Decoupling Design: Customizing Revenue Regulation to Your State's Priorities

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Acronyms

BRRT	Base Rate Revenue Target
DER	Distributed Energy Resources
EERS	Energy Efficiency Resource Standards
EM&V	Evaluation, Measurement, and Verification
FAC	Fuel Adjustment Clause
HECO	Hawaii Electric Company
LDC	Local Distribution Company
LRAM	Lost Revenue Adjustment Mechanism
PG&E	Pacific Gas and Electric
PUC	Public Utilities Commission
PV	Photovoltaic
RAM	Revenue Adjustment Mechanism
RAP	The Regulatory Assistance Project
ROE	Return on Equity
RPC	Revenue per Customer
SFV	Straight Fixed/Variable
VEIU	Vertically Integrated Electric Utility

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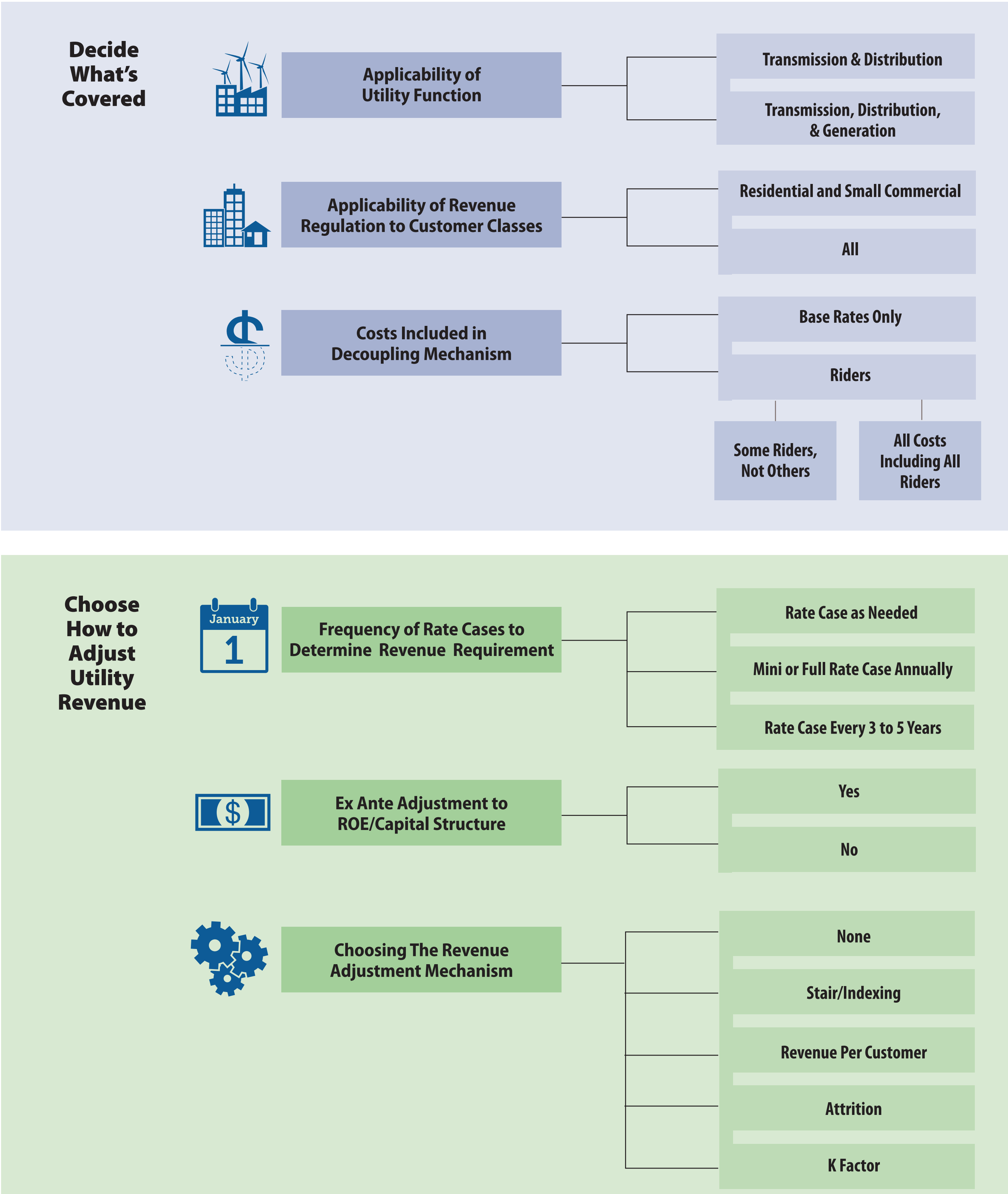
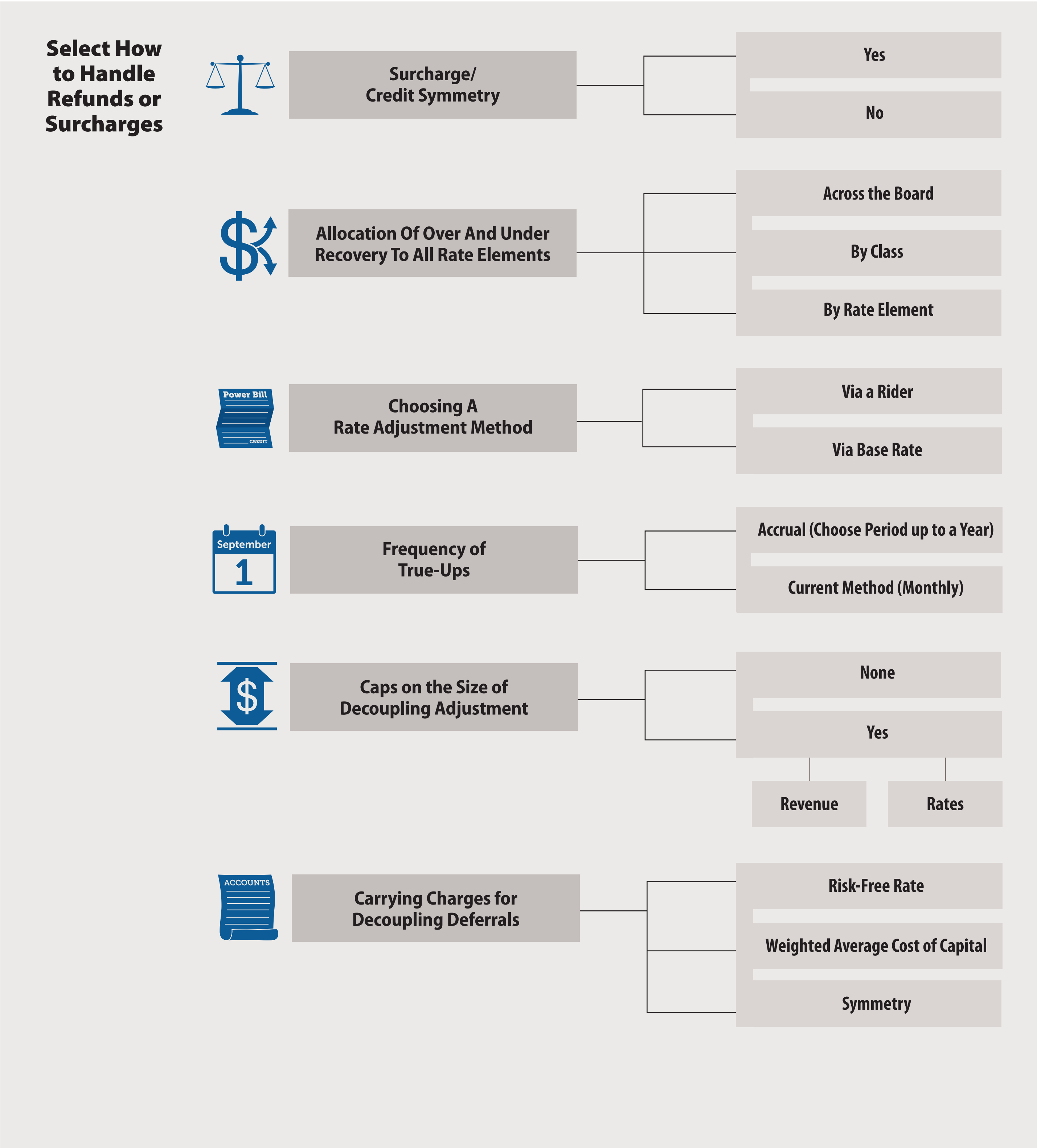
Figure 1

Decoupling Decision Points

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Surcharge/ Credit Symmetry
Yes
No
Allocation Of Over And Under Recovery To All Rate Elements
Across the Board
By Class
By Rate Element
Power Bill
Credit
Choosing A Rate Adjustment Method
Via a Rider
Via Base Rate
September
1
Frequency of True-Ups
Accrual (Choose Period up to a Year)
Current Method (Monthly)
Caps on the Size of Decoupling Adjustment
None
Yes
Revenue
Rates
Accounts
Carrying Charges for Decoupling Deferrals
Risk-Free Rate
Weighted Average Cost of Capital
Symmetry

Executive Summary

Introduction

Many states have adopted utility "decoupling,"[1] or revenue regulation, to address the impacts on utilities' revenues from factors that affect their sales levels. Originally, decoupling was conceived as a way to make utilities indifferent to annual sales volume and to address the net revenue losses associated with energy efficiency programs. More recently, it has been considered as one of many tools to mitigate revenue shortfalls from deployment of all distributed energy resources (DER).

The design process of a decoupling mechanism contains a number of decision points that address policy and stakeholder priorities. No two mechanisms are identical, and from an overall perspective of the good of the state, or from the distinct perspective of individual stakeholders, these decisions will enhance the decoupling mechanism or make it less attractive. Examples of the kinds of decisions regulators typically consider and for which stakeholders provide input include the design of the revenue adjustment mechanism, the frequency of adjustments, limits (caps) on the size of the adjustment, and other factors, which this paper will discuss in more detail.

Decoupling can increase the efficiency of utility operations, reduce risk (for both consumers and utilities), promote energy efficiency and conservation, and support deployment of DER.[2] RAP has written extensively on these benefits; this paper is the third in a trilogy of work on decoupling. The first covered the benefits of such a regulatory regime, and the second reviewed how it has worked on the ground in six states. The principal focus of this third paper will be how to make decoupling design decisions that best complement the facts on the ground and the goals of each state, each commission, and its stakeholders. It concludes with sample pathways that could be considered in designing and implementing decoupling. An appendix reviews the benefits of putting a decoupling mechanism in place.

Regulatory Conditions

Decoupling allows the utility to recover net lost revenues due to reduced sales. The concept was introduced to address a belief that it is anathema to the traditional utility business model to order a company to work hard to sell less of its product. The concept was first implemented for natural gas distribution utilities and later expanded to include vertically integrated electric utilities. Inherent downward pressure on utility sales from more efficient devices and processes, even as dependence on electricity increases, has made a difference[3] in utility attitudes toward decoupling. As the cost of renewable energy options declined, decoupling began also to be viewed in some quarters as a mechanism to deal with the impacts of distributed energy resources.[4]

1 Some also refer to decoupling as revenue regulation. These terms are used interchangeably in this paper. As used in this paper, decoupling (and revenue regulation) is defined as an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. See Lazar, J., Weston, F., & Shirley, W. (2011). Revenue Regulation and Decoupling. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/ knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application

2 Lazar, J., Weston, F., & Shirley, W. (2011). See also Migden-Ostrander, J., Watson, B., Lamont, D., & Sedano, R. (2014, July). *Decoupling Case Studies: Revenue Regulation Implementation in Six States.* Montpelier, VT: The Regulatory Assistance Project; plus numerous presentation slides available at www.raponline.org.

3 See Appendix for a discussion of the benefits of decoupling for customers and utilities.

4 For more on the treatment of DER in rates, see Hledik, R., & Lazar, J. (2016). *Distribution System Pricing With Distributed Energy Resources.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/distribution-system-pricing-with-distributed-energy-resources

Good customer service is important to customer advocates.[5] They are concerned that, if utilities are assured of revenue recovery, they may be tempted to reduce the costs necessary to maintain service quality and reliability. Along with performing well on energy efficiency, it may also be important to require that utilities under a decoupling regime meet a certain level of service and performance targets. To that end, many decoupling mechanisms include customer service quality or reliability indices.

There are a variety of ways to establish decoupling. One is by statute, which can either be an explicit direction to pursue decoupling or not, or implicit and fall under broader statutory powers granted to the utility commission (the latter is the most common). Without specific guidance, many regulators find that they have the broad statutory authority to establish a decoupling mechanism. However, others may argue that decoupling decisions must be made within the context of a rate case.

Decoupling can sometimes be achieved, as it was in Hawaii or Ohio, via a collaborative stakeholder process in which the details are negotiated among the utilities, commission staff, and intervenors. In Arkansas, the commission issued an order inviting the utilities to file a decoupling proposal with their next rate cases, stating suggested design parameters (such as low customer charges to encourage conservation) and left the rest to the utilities.[6] In Massachusetts, the Department of Public Utilities issued an order requiring electric and gas utilities to implement full decoupling and detailing how it should take place.[7] Decoupling can work well when it is part of a collaboration among parties and is supporting a comprehensive energy efficiency plan where program costs, net lost revenues[8], and incentives are addressed.

Decision Points

The issues that regulators will face, and the decisions they must make, fall into three broad categories, and which are also listed in Figure ES-1:

1. Applicability of revenue regulation: Decide what's covered

Regulators must first decide what (or who) a decoupling mechanism covers by answering a series of questions:

What utility functions are covered? For restructured utilities, the decision is simple: Decoupling would apply only to distribution, and in many cases to transmission, as the monopoly businesses of the utility. For vertically integrated utilities, it could apply to just distribution and transmission, or to all three functions, including generation. Pragmatically, the best result may be achieved by separating the distribution revenue requirement from the power supply revenue requirement, and implementing mechanisms to assure that both produce the correct amount of revenue.

What customer classes are covered? Decoupling is applied to the residential and small commercial classes because, as a group, they are fairly homogenous in their usage, no single customer's usage will account for a dominant portion of that customer class, and their rate designs are simple, making it easy to apply adjustments. Large industrial customers are usually excluded, particularly where there are only a few users in a given customer class, because decoupling can have too large an effect on other customers in the class due to sales increases or decreases by a single large customer. Still, these customers benefit from improved management focus on service and cost control.

Should all costs be included in a revenue decoupling mechanism or are there some that should be excluded?

5 For examples of good customer service plans, see Vermont Public Service Board. (2016). Service Quality Plan. Retrieved from: http://psb.vermont.gov/utilityindustries/electric/backgroundinfo/sqrp; and, New York Public Service Commission. (2004). *Order Adopting Changes to Standards on Reliability of Electric Service.* Retrieved from: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD9001691-1895-462A-A827-1BC09245548F%7D

6 Arkansas Public Service Commission, In the Matter of the Consideration of Innovative Approaches to Ratebase Rate of Return Ratemaking Including, But Not Limited to, Annual Earnings Reviews, Formula Rates, and Incentive Rates for Jurisdictional Electric and Natural Gas Public Utilities, Docket No. 08-1137-U, Order No. 19, January 2, 2013.

7 MA DPU, Order No. 07-50A, Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources, July 16, 2008.

8 "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler-than-expected summer weather, or government-mandated end-use energy investments) not occurred.

This answer depends in large measure on whether the utility is allowed to recover any specific categories of costs through a separate mechanism, such as a fuel and purchased power mechanism to recover a portion of power supply costs. If so, these costs are usually excluded.

2. How a decoupling mechanism works: Choose how to adjust utility revenue

The choice of the revenue adjustment mechanism (RAM) is perhaps the most significant decision that regulators must make in the course of a decoupling proceeding. It can also be the most controversial. Some revenue adjustments will allow for some adjustment to revenues in between cases, while others are tied to a rate case determination and possibly the frequency of rate cases. Also important in terms of the development of the revenue requirements are considerations of the capitalization ratio that reflects less risk to the utility as a result of decoupling. Finally, the mechanism should include steps to avoid double recovery of costs. RAM options include:

- ***No RAM:*** No adjustment is made to the revenue requirement until a utility files a rate case to increase it; in the meantime, rates are adjusted via periodic true-ups. Some consumer advocates support this out of concern over increasing rates and lack of opportunity to verify the increases.
- ***Stair-step:*** Adjustments are pre-determined in a rate case and are usually based on forecasts of projected cost increases. The benefit of this is that it can provide revenue stability based on pre-determined choices that translate into financial benefits for the utility and its customers. The downside is that costs are difficult to forecast accurately.
- ***Indexing:*** Adjustments are tied to multiple factors, such as general or industry inflation, industry productivity, customer growth, and changes in capital. This may be a reasonable compromise because it can account for known or likely utility cost changes without necessarily having major rate impacts.
- ***Revenue per customer (RPC):*** Regulators determine the revenue requirement on a per-customer basis (usually by customer class), and the total system revenue requirement is determined by multiplying the number of customers in each class by the revenue requirement for each customer in that class. This is frequently used for distribution utilities and is among the most popular mechanism; a benefit is that customers do not end up compensating a utility for lost revenues due to lost customers.
- ***Annual review (or attrition):*** Periodic reviews are used to adjust base rates for known and measurable changes in rate base and operating expense. More controversial larger changes, such as major plant additions, are left for a full rate case (unless there is an applicable tracker in place, in which case it would not be part of the decoupling mechanism).
- ***K factor:*** An adjustment is used to increase or decrease overall growth in revenues between rate cases, if a key assumption (such as increased efficiency or growth in rooftop solar) is likely to vary significantly during the decoupling period. The K factor can vary from year to year but is usually set at a prescribed level in between rate cases. A K factor coupled with an RPC can be convenient, while also addressing the challenge of tracking the effects of these changing cost drivers.
- ***Hybrid:*** Regulators may use a combination, or hybrid, of regulatory mechanisms. For example, a combination of RPC and K Factor may be used so that the allowed revenue per customer grows (or declines) according to a historical trend factor as the mix of customers changes over time.

After choosing the RAM, regulators must also consider:

How frequently should the revenue requirement of a utility should be reviewed? In some jurisdictions, such as New York, the regulators will not set a schedule and instead leave it to the utility to decide when it needs to file for a full rate case review. Most commissions have incorporated periodic reviews in their decoupling orders to ensure that underlying assumptions remain valid and rates are in line with costs. Another approach is what we refer to as "annual review" decoupling, used by California and Hawaii utilities, in which "mini rate cases" are built into the process.

How should utility risk factor into decoupling? Two mechanisms can address this. The more common is to reduce the cost of equity, which translates into a lower return to the utility and saves customers money. The utility return on equity (ROE) is intended to compensate shareholders for risk, and capital markets interpret the message embedded in a state's ROE decision and other regulatory decisions. A second mechanism is for regulators to adjust the capital structure to increase the debt portion (for which a lower return is required) and decrease the equity portion (for which a higher return is required).

3. Decoupling adjustments: Select how to handle refunds or surcharges

Decoupling is designed to assure that actual revenues match authorized revenues during the life of the mechanism. Typically, however, these do not line up exactly. Decoupling adjustments serve to either refund revenue surplus or recover revenue deficits. One of the key objectives of decoupling in the eyes of consumer representatives is a mechanism whose adjustments are *symmetrical,* which is to say that over-collections are treated in the equivalent, but opposite, manner as under-collections. A further series of regulatory decisions must be undertaken to ensure this:

Allocating over- and under-recoveries to customers: Methods include a uniform surcharge or credit per kilowatt-hour (kWh) to all decoupled classes; a uniform percentage surcharge or credit to all rate elements; or "class-by-class" decoupling, in which allowed revenue is computed separately for each class and used to produce a uniform adjustment (either by kWh or percentage) for all customers in that class. The decoupling mechanism generally leaves rate design unaffected by applying either a uniform $/kWh or uniform percentage adjustment, but this need not be the only option. The mechanism can change rate design to complement policy goals. It can, for example, reward lower-use customers on an inclining block rate by allocating any refund to the first block and applying surcharges to the tail block.

Adjustment to base rates or through a purpose-built rider: Unless there is a statute in place authorizing recoveries through a specific mechanism,[9] regulators normally will have the discretion to decide this issue. A factor may be the revenue adjustment mechanism chosen. For example, if the adjustment mechanism requires annual mini rate cases, regulators may opt to fold any adjustments into the rate case rather than into a separate rider. Conversely, if there is no mandate for frequent rate cases, a rider (which, as discussed in this paper, means an adjustment to base rates rolled into a customer's total rate, not a surcharge on a bill) may be a more practical approach to reconcile any adjustments.

Frequency of true-ups: The typical choices are monthly, quarterly, and annually. Monthly is the low limit because billing is monthly, while annual is the upper limit to avoid excessive divergence between expected and actual revenues. Monthly adjustments tend to be more accurate in matching actual and authorized revenues, while a longer period, such as a year, has the benefit of smoothing out shorter-term volatility and tends to result in smaller adjustments—positive or negative—overall. A weather-only normalization can be used as a form of real-time decoupling adjustment.

Caps on the size of decoupling adjustments: While adjustments resulting from a RAM tend to cluster in the -1 to +3 percent range, they can be larger or smaller, as either a surcharge or credit.[10] Many regulators adhere to the principle of gradualism so as to minimize rate shock and make it easier for consumers to adjust to new prices. A cap can manage customer expectations and impacts. Not all utilities have such caps; some regulators may not be fans of deferrals and may instead prefer to allow the true-up to reflect the full extent of any adjustment, and some have limited surcharges but allowed full flow-through of credits. For those that prefer to limit rate impacts, there are various mechanisms for capping rates, from a cap on the percentage of a permissible rate change, to a cap on total revenue increases (as opposed to rate increases), to setting the cap in dollars, not as a percentage. Unrecovered amounts must be considered, usually via the handling of deferral balances and true-ups.

Carrying charges: With the exception of decoupling mechanisms that adjust rates monthly, the utility will either carry a deferred balance for collection or refund to customers.[11] There are two instances in which carrying charges could be considered: if true-up of charges occurs over an interval, such as a year, so that a portion of the accumulated true-up amount remains unrecovered between reconciliation, or if there is a cap on the size of the reconciliation adjustment permitted in any given adjustment period and the unrecovered portion of the adjustment is carried over for the subsequent time period. Regulators will need to decide if carrying costs should apply to one or both instances and how much those costs should be.

Additional Considerations

Revenue regulation does not need to be accompanied by other policies and can be implemented on a stand-alone basis. However, consideration of some of the implications of decoupling in terms of benefits to the utilities, policy goals,

9 A state may have a prohibition from adjusting base rates outside of a full revenue requirement investigation, but this may allow for an adjustment of a rider in a decoupling mechanism.

10 See Figure 3 on p19.

11 Even in the case of current method decoupling (see p26), a balancing account may be needed if the cap is invoked in a month of extreme volatility.

and rate designs may result in regulators making certain decisions with regard to complementary policies and the conditions for decoupling.

Performance evaluation: Decoupling is sometimes associated with performance- or outcome-based regulation. Why? If the utility is no longer worried about sales because the throughput incentive is neutralized, management is then ready to hear government priorities conveyed in the form of goals and financial incentives that promote excellence and innovation. The periodic rate reconciliation is also an opportunity to apply performance-based rewards and penalties to rates. Some, however, believe that the performance system is a distraction, that utilities should perform with excellence without the need for rewards, and that the existing powers of regulation provide penalties for poor performance. Under any regulatory paradigm, decoupling is a distinct issue from performance metrics.[12]

Rate design: As energy efficiency deployment grows and

Table ES-1

Representative Pathways: Three Straw Scenarios

Element	Scenario 1	Scenario 2	Scenario 3
Applicability	Retail choice or VIEU*	Retail choice or VIEU	VIEU
Function	Distribution	Distribution	Distribution and generation
Customer Class	Residential and small commercial	Residential, commercial, and industrial	Residential, commercial, and industrial
Excluded Costs	All distribution-related tariff riders	All distribution-related tariff riders	All costs addressed by tariff riders
Rate Case Frequency	No requirement	Full scale every 3 to 5 years	Annual mini rate case
Revenue Adjustment	RPC with K Factor	No RAM	Annual review decoupling
Symmetry	Yes	Yes	Yes
Recovery Allocation	Across the board to residential and small commercial	Customer class contribution to total revenue defines amount for each class	Customer class contribution to total revenue defines amount for each class
How Recovered	Rider	Rider	Base rates
Frequency of True-Ups	Monthly	Annually	Monthly
Carrying Costs	No	Yes	Yes
Caps	10% rate difference	3% rate difference	No cap
Regulatory Conditions	Energy efficiency programs, customer service quality, and other distributed energy resource programs	Energy efficiency programs, distributed energy resources, and customer service quality	Energy efficiency programs, distributed energy resources, and customer service quality
Rate Design and Allocation of Reconciliation	Inclining block; credits on first block; surcharge on second block	Inclining block; credit on first block; surcharge on second block; *or* time-of-use; refund on off-peak; surcharge on on-peak	Inclining block; credit on first block; surcharge on second block; *or* time-of-use; refund on off-peak; surcharge on on-peak
Return on Equity	No change	No change	No change
Capital Structure	Reduce equity ratio	Reduce equity ratio	Reduce equity ratio within annual review

** VIEU: vertically integrated electric utility.*

12 Lazar, J. (2014). *Performance-Based Regulation for EU Electric Distribution Utilities.* Retrieved from: http://www.raponline.org/knowledge-center/performance-based-regulation-for-eu-distribution-system-operators

the cost of customer-sited alternatives such as rooftop photovoltaics (PV) continue to decline, there is a growing debate over utility revenue collection and customer compensation. Decoupling is a tool regulators can use to manage this conflict, leaving the focus of rate design on customer price signals and other policy priorities. If a regulator has ordered the utility to adopt decoupling, the need for high fixed charges or demand charges becomes inconsequential to shareholder earnings, because, at least in the short term, the utility has a greater ability to recover its revenue requirement.

Bill simplification: Decoupling requires periodic adjustments in customer rates. It is important for the rates, as they appear on the customer bill, to be understandable. Many utilities' bills include separately stated line items for various charges, usually linked to specific tariff riders, which can cause customer confusion. It is essential that bills show just the effective rate, which includes all surcharges, credits, and taxes, so that customers understand how much they will save if they use less electricity, and how much they will pay if they use more.

Potential Decoupling Pathways

Considering all the options outlined above, RAP has put together for consideration three scenarios that include the major elements of decoupling (See Table ES-1):

- ***Scenario 1*** applies to a distribution-only utility or a vertically integrated electric utility that has adopted decoupling for distribution services only. This scenario differs from the others in that it has a monthly true-up recovered through a rider. As a result, there are no carrying costs, but rates are subject to larger monthly fluctuations that may be necessary to explain to customers. We also added a performance metric for customer care and reliability; although a performance metric is not integral to a decoupling mechanism (which is the reason for its absence from Scenarios 2 and 3), it is certainly worthy of consideration.
- ***Scenario 2*** is similar to Scenario 1 in that it applies to the distribution function only. A distinguishing factor, however, is that this decoupling mechanism applies to all customer classes, including industrial. In this case, as in Scenario 3, there is a significant number of industrial customers to warrant their inclusion in the decoupling mechanism.
- ***Scenario 3*** differs from the first two scenarios in that it applies to a vertically integrated utility and to its distribution and generation functions. Unlike Scenarios 1 and 2, which rely on riders for recovery of over- and under-recoveries, Scenario 3 requires annual mini rate cases to adjust revenues and reconcile rates with revenue requirements.

Across the board, there is no adjustment in any scenario to the return on equity. Return on equity adjustments are poorly received by the utility and the investment communities and could contribute to an investment downgrading, which then could increase the cost of borrowing—a cost passed on to consumers. A better way to reflect the reduction in risk is through a change in the capital structure that reduces the equity ratio.

Conclusions

On a macro level, decoupling separates sales from revenue. However, on a micro level, there are myriad details in how that is done. Assumptions about these details influence the wide variety of viewpoints about this issue, both supportive and critical, that are seen in the power sector. Understanding decoupling, therefore, perhaps should start with an understanding of these assumptions.

This paper points to certain pathways that RAP would recommend over others. They include:

- Symmetry in over- and under-recoveries;
- Exclusion of costs recovered through separate tariff riders, to avoid over-collection of costs;
- Reduction in equity ratio, rather than an adjustment of the return on equity, to reflect lower risk; and
- Performance requirements to foster energy efficiency, the development of distributed resources, and quality service levels.

Other factors vary by jurisdiction and need to be decided as well, including, most importantly, which RAM to use, but also cost allocation by customer class, mechanisms for and frequency of cost recovery, caps, and the issue of carrying costs.

Decoupling can be applied to any utility. While it may be a more obvious option for a regulated utility, it can also be applied to municipal utilities (munis) and co-operatives (co-ops). In any event, there is no one answer to the question, "How should this utility decouple revenues from sales?" For each company, state, and time, the answer should represent the priorities of the day, guided by the framework laid out here.

Ultimately, a good decoupling mechanism may best be driven by a consensus among the stakeholders, reached via a collaborative process in which the mechanism chosen and the decisions made balances the interests of all parties.

I. Introduction

Decoupling[13] mechanisms have been adopted in many states as a means of addressing the impacts on utilities' revenues from factors affecting the levels of their sales. Originally conceived as a way to make utilities indifferent to annual sales volume and to address the net revenue losses associated with energy efficiency programs, it has more recently been considered to be one of many tools to mitigate revenue shortfalls from deployment of all distributed energy resources (DER). A decoupling mechanism contains a number of decision points in its design that address policy and stakeholder priorities. A decoupling mechanism is not static; rather, it offers a multitude of design options. No two decoupling mechanisms seem to be identical. From an overall perspective of the good of the state, or from the distinct perspective of individual stakeholders, these decisions will enhance the decoupling mechanism or make it less attractive. Examples of the kinds of decisions regulators typically consider and for which stakeholders provide input include the design of the revenue adjustment mechanism, the frequency of adjustments, limits (caps) on the size of the adjustment, and other factors that are discussed in more detail herein.

The Regulatory Assistance Project (RAP) has written frequently on decoupling over the course of the past few years because of its importance as a tool to achieve the public policy objectives of, among other things, improving the efficiency of utility operations, reducing risk (for both consumers and utilities), promoting energy efficiency and conservation, and supporting deployment of DER.[14] The benefits of a well-designed decoupling mechanism are manifold and are discussed briefly; however, the principal focus of this paper is on the various decisions in how to design decoupling so that it can best complement the facts on the ground and the goals of each state, each commission, and its stakeholders. This paper then concludes with sample pathways that could be considered in designing and implementing decoupling. For the reader who is unsure of the benefits of decoupling, we have attached a discussion (see Appendix).

A. The Regulatory Conditions for Decoupling

Decoupling is a tool that allows the utility to recover net lost revenues attributable to reduced sales. Its genesis was in energy efficiency programs under the premise that it is anathema to the traditional utility business model to order a company to work hard to sell less of its product. Regulators who believe that energy efficiency is in the public interest often decide to implement a mechanism to make the utility whole for any net lost revenues resulting from its government-mandated efficiency efforts. Decoupling offers an elegant method for this purpose. Other stakeholders who supported decoupling often did so with the understanding that the utility would be obligated to deliver a comprehensive portfolio of energy efficiency programs.

The first decoupling mechanisms were created for natural gas distribution utilities, which do not have "production" plants in their company-owned asset base (and hence resemble a restructured, wires-only electric utility). They were later extended to include vertically integrated electric utilities. Inherent downward pressure on utility sales from more efficient devices and processes, even as dependence on electricity and the number of devices

13 See Lazar, J., Weston, F., & Shirley, W. (2011). *Revenue Regulation and Decoupling*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/ knowledge-center/revenue-regulation-and-decoupling-aguide-to-theory-and-application

14 Lazar, J., Weston, F., & Shirley, W. (2011). See also Migden-Ostrander, J., Watson, B., Lamont, D., & Sedano, R. (2014). *Decoupling Case Studies: Revenue Regulation Implementation in Six States.* Montpelier, VT: The Regulatory Assistance Project; plus numerous presentation slides available at www.raponline.org.

increases, has made a difference[15] in utility attitudes toward decoupling.

Later, as the cost of renewable energy options declined, decoupling began to be viewed in some quarters as a mechanism to deal with the impacts of DER.[16] Decoupling offers the distinct advantage of reducing risk and ensuring revenue recovery, consistent with the setting of "just and reasonable" rates, which does not change with decoupling. This has value to consumers, who also benefit from reduced risk, as it can lower the cost of borrowing for the utility. Decoupling enables a commitment within utility management along with the execution of substantial energy efficiency, which is the benefit of the bargain that will accrue to all stakeholders.[17] In future decoupling plans, conditions pertaining to enabling other DER may appear.

Good customer service is important to customer advocates.[18] They are concerned that, if utilities are assured of revenue recovery, they may be tempted to reduce costs by cutting services necessary to maintain service quality and reliability. Along with performing well on energy efficiency, it may be important to also require that utilities meet a certain level of service as part of the exchange in obtaining decoupling. Many decoupling mechanisms include customer service quality or reliability indices, which penalize utilities if service falls below a defined threshold.

15 See Appendix for a discussion of the benefits of decoupling for customers and utilities.

16 For more on the treatment of DER in rates, see Hledik, R., & Lazar, J. (2016). *Distribution System Pricing With Distributed Energy Resources.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/distribution-system-pricing-with-distributed-energy-resources/

17 For more on the benefits of energy efficiency, see Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency

18 For examples of good customer service plans, see Vermont Public Service Board. (2016). Service Quality Plan. Retrieved from: http://psb.vermont.gov/utilityindustries/electric/backgroundinfo/sqrp; and New York Public Service Commission. (2004). Order Adopting Changes to Standards on Reliability of Electric Service. Retrieved from: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD9001691-1895-462A-A827-1BC09245548F%7D

Designing Decoupling

1. Decide what's covered

Decoupling can be applied to:

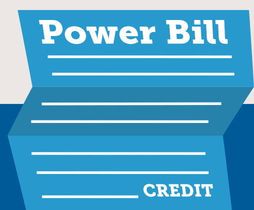
- Distribution alone
- Distribution and transmission
- Distribution, transmission, and generation

It can cover residential, commercial, and industrial customers or apply selectively. Exclude fuel or power purchase costs if they are already covered in a rider, fuel adjustment mechanism, etc.

2. Choose how to adjust utility revenue

There are about a half-dozen options for "Revenue Adjustment Mechanisms" (RAMs) to adjust utility revenue to provide stability to utilities and customers. Among them:

- Revenue per customer
- Annual review decoupling
- No adjustment at all



3. Select how to handle refunds or surcharges

Truing up actual utility revenues with what utilities are allowed to earn can be done monthly or at longer intervals. Refunds or charges can be applied to all customers evenly or be allocated to customer classes. They can also be directed to encourage a particular policy goal, like rewarding low energy usage.

Customer Considerations

- Refunds if utilities over-collect
- Caps on rate increases or decreases?
- More energy efficiency
- Reducing cost of capital

II. Decoupling Design: Decision Points

This paper is the third in a trilogy of RAP papers on decoupling. In the first, we explained the intricacies of decoupling: how it works and what it accomplishes. In the second, we conducted six case studies of decoupling mechanisms around the United States.[19] This third paper examines how to construct a decoupling mechanism: it identifies the many decision points that regulators will want to address when designing a decoupling regime.

The issues that regulators face and the decisions they must make fall into three broad categories:

1. Applicability of revenue regulation: decide what's covered
2. How a decoupling mechanism works
3. Decoupling adjustments: select how to handle refunds or surcharges

A. Legal Authority to Establish Decoupling

Before we dive into the decisions necessary to create a decoupling mechanism, it is important to address the variety of ways to establish decoupling. One method of establishment is by statute, which can either be an explicit direction to pursue decoupling (or not), or it can be implicit and fall under broader statutory powers granted to the commission, which is the most common. If it is explicit in the statute, it becomes a *fait accompli,* but how the mechanism works will be determined in a commission proceeding and may depend on any statutory requirements that might be included in the legislation. Without specific statutory guidance, many regulators find that they have the authority to establish a decoupling mechanism under their broad statutory authority to regulate public utilities. However, where there is no specific statutory grant of authority, others may interpret a prohibition on changing base rates outside a rate case, and limit commission authority. In this case, decoupling would have to take place in a rate case, with any adjustment to the revenue requirements occurring in a subsequent rate case.

Decoupling mechanisms can be accomplished in a variety of ways at the regulatory level. Decoupling can sometimes be achieved when the utilities, commission staff, and the interveners collaborate to develop a proposal to which all parties can agree and that addresses the concerns of a range of stakeholders. This can occur through negotiations in a rulemaking or in a utility case-specific proceeding. In Hawaii, the governor, Hawaii Electric Company (HECO), and the consumer advocate entered into an agreement called the Clean Energy Initiative. The commission in turn opened a docket on revenue regulation and ordered HECO, the state, and the consumer advocate to develop a joint recommendation in 60 days.[20]

In Ohio, after Energy Efficiency Resource Standards (EERS) were enacted by the legislature, the Ohio Consumers' Counsel and American Electric Power Company negotiated a decoupling agreement as part of a rate case settlement.[21]

Arkansas took a different approach. Wanting to encourage its utilities to file for decoupling, the Arkansas Public Service

19 Lazar, J., Weston, F., & Shirley, W. (2011). See also Migden-Ostrander, J., Wason, B., Lamont, D., & Sedano, R. (2014); plus numerous presentation slides available at www.raponline.org

20 Hawaii Public Utilities Commission, Docket 2008-0274.

21 SB 221 resulted in the passage of the EERS in 2008. Despite overwhelming evidence of the success of the EERS in terms of customer savings, the legislature froze the EERS in SB 310 in 2014. The case that approved the decoupling mechanism for American Electric Power Company was Public Utility Commission of Ohio (PUCO) Case No 11-351-EL-AIR, Opinion and Order, December 14, 2011. Although the decoupling mechanism is still in effect and is working well, the Commission has ordered all the electric utilities to file straight fixed/variable rates instead of decoupling in their next case. PUCO Case No. 10-3126-EL-UNC Order, August 21, 2013.

Commission issued an order inviting the utilities to file a decoupling proposal with their next rate cases.[22] In the order, the commission specified certain design parameters that it believed were in the public interest, but left the rest of the design decisions to the utility and required them to provide the rationale for their design recommendations. Specifically, the commission ordered: (1) that the customer charge be set low enough to encourage customer conservation; (2) that the utility establish separate revenue-per-customer amounts for, at a minimum, residential, small commercial, and demand-metered commercial customers; and (3) that the true-up mechanism be symmetrical to adjust for over- and under-recoveries. In Washington, the Utilities and Transportation Commission issued a policy statement on November 4, 2010, that expressed their views on several design elements for decoupling.[23]

In Massachusetts, the Department of Public Utilities issued an order requiring decoupling and detailing how it should take place. Decoupling is still in effect in Massachusetts.[24] That order required electric and gas utilities to implement full decoupling, with an annual reconciliation to help implement the "Green Communities Act" that had been passed by the Massachusetts legislature to promote energy efficiency, demand response, and distributed generation.[25]

Decoupling can work well when it is part of a collaboration among parties and supports a comprehensive energy efficiency plan in which program costs, net lost revenues, and incentives are addressed to encourage utility progress and provide benefits to customers.

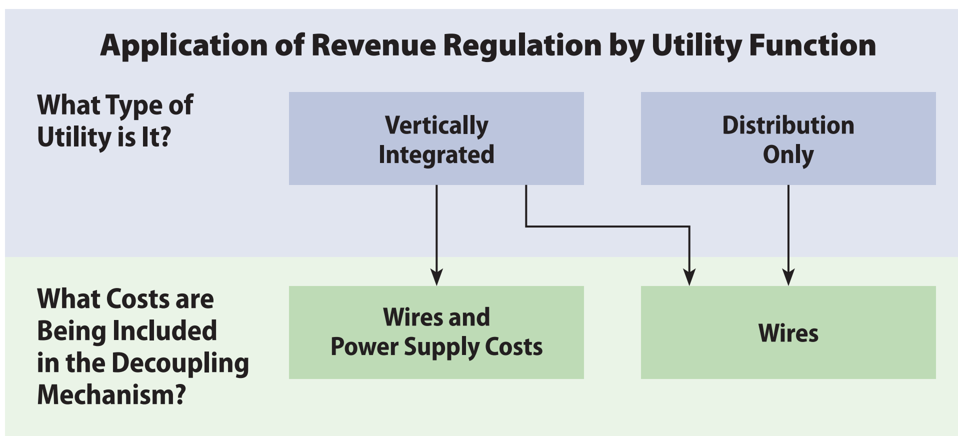
B. Applicability of Revenue Regulation: Decide What's Covered

Deciding what (or who) is covered by a decoupling mechanism is the first category of decisions to make. The effects of the decoupling mechanism will vary widely depending on what utility functions are covered (generation, transmission, and distribution); which customer classes are covered (residential, small commercial, or all customer classes); which costs are included and excluded; and by utility type. This section describes the options under each category and relevant considerations for each choice.

1. Applicability of Revenue Regulation by Utility Function

Revenue regulation can be applied to any and all utility functions (generation, transmission, and distribution). For restructured utilities the decision is simple. Decoupling would apply only to distribution and in many cases to transmission as the monopoly businesses of the utility. For vertically integrated utilities, it could apply to just

Figure 2



22 Arkansas Public Service Commission, In the Matter of the Consideration of Innovative Approaches to Ratebase Rate of Return Ratemaking Including, But Not Limited to, Annual Earnings Reviews, Formula Rates, and Incentive Rates for Jurisdictional Electric and Natural Gas Public Utilities, Docket No. 08-1137-U, Order No. 19, January 2, 2013.

23 Washington State Utilities and Transportation Commission, Docket No. U-100522, Report and Policy Statement on Regulatory Mechanisms, including decoupling, to encourage utilities to meet or exceed their conservation targets, November 4, 2010.

24 MA DPU, Order No. 07-50A, Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources, July 16, 2008.

25 Commonwealth of Massachusetts, Chapter 169 of the Acts of 2008.

26 "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler than expected summer weather or government-mandated end-use energy investments) not occurred.

distribution and transmission, or to all three functions, including generation. Figure 2 illustrates this application of decoupling mechanism by utility function.

Pragmatically, the best result may be achieved by separating the distribution revenue requirement from the power supply revenue requirement, and implementing mechanisms to assure that both produce the correct amount of revenue. The Washington Utilities and Transportation Commission (WUTC) implemented such a mechanism for Puget Sound Energy; the distribution revenue requirement is subject to a decoupling mechanism, and the power supply revenue requirement is subject to a power cost adjustment mechanism.[27]

2. Applicability of Revenue Regulation to Customer Classes

Decoupling is applied to the residential and small commercial classes, because as groups they are fairly homogenous in their usage, unlike the industrial class, in which there are large differences among customers in how they use electricity. Moreover, for the residential and small commercial class, there is no single customer whose usage requirements comprise a dominant portion of that customer class. The simplicity of their rate designs usually makes it easy to calculate an adjustment to a volumetric rate that is fair for all customers in that rate class.

For larger customers who have special contracts that

Gas Decoupling

The focus of this paper is on electric decoupling; however, a word about gas decoupling for local distribution companies (LDCs) is in order, especially because there are many utilities that have adopted it. Gas utility structure and operations lend themselves more easily to decoupling than perhaps the more complex and diverse structures in place in the electric industry, which have far more capital-intensive costs for production resources.

Today, practically all gas utility companies are distribution-only companies. Distribution costs are generally stable in the short-run. Natural gas is procured by the LDC for the customer in one of two ways: either the LDC directly procures the gas on the market or it procures it through a competitive bid auction. In either event, the LDC recovers the cost of gas through an adjustment clause. It is a pure pass-through in which the LDC neither earns nor loses money. A third method exists in states with retail gas competition in which the end-use customer contracts with a third-party supplier, a gas marketer, to provide their gas. Examples include Texas, Georgia, and Ohio. In this case, like the two examples mentioned earlier, the LDC does not earn or lose money on gas sales. Thus, the focus for the LDC is the distribution rate and ensuring that it covers its costs and earns a reasonable return for shareholders. This simplifies the decoupling process.

Gas companies worry more about sales volatility caused by weather than do electric companies. Although a long, cold winter helps increase sales and thus revenues, a short, warmer winter results in reduced sales and less revenues. By the same token, customers worry about the size of their gas bill. A particularly cold winter can result in higher than average winter gas bills. Decoupling eliminates the risk for both the utility and the consumer caused by weather volatility by basing utility revenues on the amount authorized by the commission in a rate case and not on weather conditions. Because many gas utilities already have weather normalization mechanisms, moving to gas decoupling does not represent a major shift from how rates are determined currently for those utilities.

Many of the same decision points discussed in this paper on electric decoupling are also applicable to gas decoupling, such as the frequency of true-ups, but many are straight-forward, such as applying the mechanism to all customer classes and ensuring symmetry to reflect both under- and over-recoveries. Requiring a certain frequency of rate cases should be included to periodically reconcile rates with costs, but this is not always done. Furthermore, because of the relative simplicity of gas decoupling as compared to electric decoupling, the discussion of costs to be included or excluded from the decoupling mechanism falls away, as it is really just a question of addressing the revenue requirements for the distribution service.

27 See WUTC v. Puget Sound Energy, Docket No. 12 1697; also see discussion further in this paper, in text box on page 20: "Avoiding Double Recovery."

might include an economic development or curtailable rate, applicability can be more complicated. In situations in which there are very large industrial customers in the class, especially in the case where there may be only a few customers in the industrial class, decoupling can have too large an effect on other customers in the class, owing to sales increases or decreases by a single large customer. In these cases, industrial customers are nearly always excluded from the decoupling mechanism (even as these customers benefit from improved management focus on service and cost control).

Idaho Power and Light applies decoupling to only residential and small commercial customers, whereas National Grid in Massachusetts applies it to all customer classes.[28]

3. Applicability to Cost Categories: Costs Included in or Excluded From the Decoupling Mechanism

Should all costs be included in a revenue decoupling mechanism or are there some that should be excluded? The answer depends in large measure on whether the utility is allowed to recover any specific categories of costs through a separate mechanism. If the utility has a separate mechanism to track discrete costs that are recovered on a fairly regular basis, these costs are usually excluded from a decoupling mechanism to avoid the risk of double counting.

For example, if a fuel and purchased power mechanism recovers a portion of power supply costs, all power supply costs should be removed from the decoupling mechanism to avoid risk of double recovery. If an infrastructure tracker is in place to address replacement of older distribution plant or to manage an escalating capital investment need, that category of distribution plant should be removed from the decoupling mechanism to avoid double recovery of those costs. The bottom line is that if there is a tracker to permit accelerated recovery of discrete costs, those costs should be excluded from a decoupling mechanism because they are accounted for elsewhere. When it comes to surcharges in general, any surcharge added to customer bills is troublesome because it is generally additive to rates; adjustment mechanisms are seldom requested by utilities to track costs that are decreasing owing to productivity and technology improvements. In that vein, there may a preference for including as much into base rates and removing trackers when possible. The decoupling mechanism is different in that it is based on revenue requirements and not a cost added to revenue requirements. Thus, it can reduce rates if the utility has over-recovered.

4. Applicability of Decoupling to Utility Type

Decoupling is applicable for utilities without shareholders, such as municipal electric systems that are government-owned and cooperative electric companies that are member-owned and also need to ensure adequate revenues. With some adaptation, the decision steps covered in this paper can be applied to these companies as they face the same challenges when there is a reduction in sales owing to energy efficiency and other customer actions. Companies with no equity shareholders remain concerned about revenue adequacy to cover bond covenants, are deploying distributed energy resources, want efficient regulation, and the rest.[29] For these companies, adjustments to the return on equity would not be applicable, nor might it be necessary to regiment the frequency of rate cases. On the issue of performance, an adaption for these utilities could be the opportunity to reward employees who contribute to exemplary utility results.

Recently the Los Angeles Department of Water and Power adopted a decoupling mechanism known as the "Base Rate Revenue Target" (BRRT). The BRRT is described as a mechanism to encourage water and power conservation while recovering the utility's fixed costs of providing service. Under the BRRT, revenues above the sales target will be returned to customers, while revenues below the sales target will be recovered from customers through charges over the next calendar year.[30]

28 Idaho Public Utilities Commission, IPC-E-04-15 – Idaho Power – Investigation of Financial Disincentives; Massachusetts Department of Public Utilities, Docket 09-39, Petition of Massachusetts Electric Company, November 30, 2009.

29 Although municipal utilities do not have equity shareholders, they typically have significant equity (retained earnings). This is measured as the difference between net plant in service and outstanding debt.

30 Los Angeles Department of Water and Power, 2016-2020 Rate Changes Fact Sheet. Retrieved from: http://www.myladwp.com/2016_2020_rate_request

C. How a Decoupling Mechanism Works

1. Choosing the Revenue Adjustment Mechanism

The determination of the revenue requirement and how and when it is adjusted is inextricably tied to the revenue adjustment mechanism selected. Some revenue adjustments allow for some adjustment to revenues in between cases, whereas others are tied to a rate case determination and possibly the frequency of rate cases. Also important in terms of the development of the revenue requirements are considerations of the capitalization ratio that reflects less risk to the utility as a result of decoupling.

The choice of the revenue adjustment mechanism is at the heart of decoupling and perhaps the most significant decision that regulators have to make in the course of a decoupling proceeding. It can also be the most controversial. At the conclusion of a rate case, regulators establish the revenue requirements. The revenue requirement is not static and will grow as utility costs increase over time (at least from inflation plus other pressures). In the absence of decoupling, the utility tends to work to increase sales within the capacity of existing assets to generate additional net revenues to offset upward rate pressures. When cost increases associated with operating the utility overwhelm the impact of sales growth and reach a critical level, the utility then files for a rate increase. The Revenue Adjustment Mechanism (RAM) allows the utility to adjust for some or all of these costs (depending on the RAM chosen) in order to reflect the growth in revenue requirements without a full-blown rate case. Nevertheless, a RAM is not necessary to have a fully functional decoupling mechanism in place. Table 1 provides a simple illustration.

Table 1

Periodic Decoupling Calculation	
From the Rate Case	
Target Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10000
Post Rate Case Calculation	
Actual Unit Sales	99,500,000
Required Total Price	$0.1005025
Decoupling Price Adjustment	$0.0005025

The RAM options include:[31]

- No RAM
- Stair-Step
- Indexing
- Revenue Per Customer
- Annual Review Decoupling (also known as Attrition Decoupling)
- K Factor
- Hybrid

Each is discussed in more detail here.

No RAM

A no-RAM mechanism is based on the supposition that no adjustment is made to the revenue requirement. Rates are periodically adjusted in a true-up based on the revenue requirement approved by the regulator in the last rate case. The revenue requirements are not adjusted until the utility files a rate case to increase its revenue requirement. Increasing rates is a cause for consumer concern, especially if there is an insufficient opportunity to verify the increases. Furthermore, consumers worry about selective adjustments that only increase rates without accounting for cost reductions, because there is no opportunity to net decreased costs against increased costs. For this reason, some consumer advocates support having no revenue adjustment mechanism. This problem can be particularly acute if some rising costs are addressed by separate tracker mechanisms.

Stair-Step

Stair-step adjustments are predetermined in a rate case and are usually based on forecasts of projected cost increases. The benefit of this revenue adjustment mechanism is that it can provide revenue stability based on predetermined choices that translate into financial benefits for the utility and its customers. The downside of this kind of adjustment is accuracy in determining actual costs in that forecasts are never entirely accurate. In jurisdictions that use a future test year, this may seem to be just an extension of current

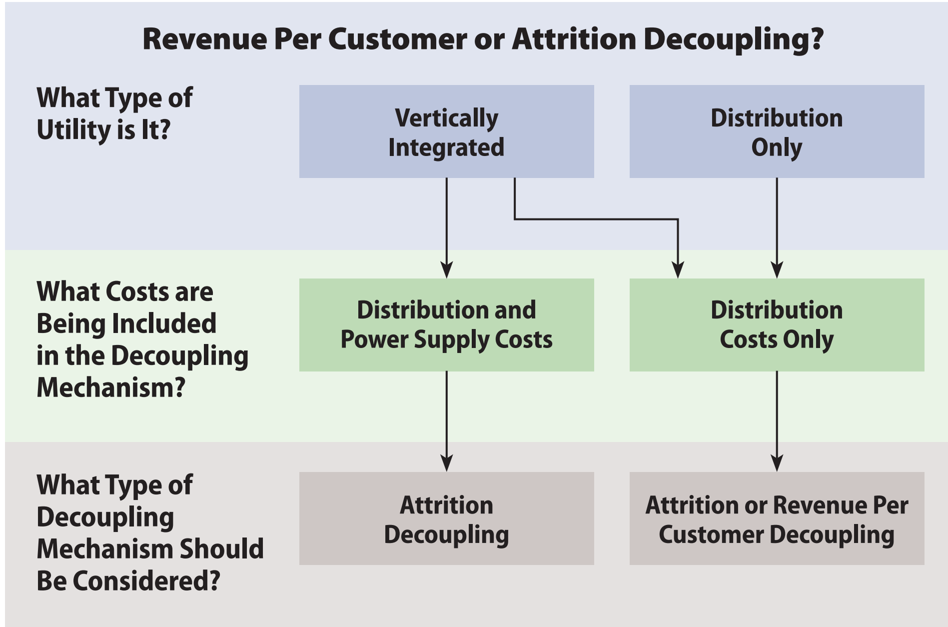
31 For more on these definitions, see Lazar, J., Weston, F., & Shirley, W. (2011).

practice. It may be viewed elsewhere as problematic in that, by the nature of it being based on forecasts, it lacks the qualities of being known and measurable. Generally, any revenue adjustment mechanism should account for known and measureable increases. Thus a true-up between actual and forecasted increase is advised.

Indexing

Under indexing, adjustments to the revenue requirement are tied to multiple factors, such as general or industry inflation, industry productivity, customer growth, and changes in capital. The indexing adjustment can account for known or likely utility cost changes without necessarily having major rate impacts. As such, it may be a reasonable compromise to account for some cost increases without re-evaluating the entire revenue requirement.

Figure 3



Revenue Per Customer

The Revenue Per Customer (RPC) mechanism adjusts the revenue requirement for the total number of customers served. Regulators determine the revenue requirement on a per-customer basis (usually by customer class) so that the total system revenue requirement is determined by multiplying the number of customers in each class by the revenue requirement for each customer in that class. Table 2 illustrates how this works.

Table 2

Revenue Per Customer Periodic Decoupling Calculation	
From the Rate Case	
Target Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10000
Number of Customers	200,000
Revenue per Customer (RPC)	$50.00
Post Rate Case Calculation	
Number of Customers	200,500
Target Revenues ($50 x 200,500)	$10,025,000
Actual Unit Sales	99,750,000
Required Total Price	$0.1005013
Decoupling Price "Adjustment"	$0.0005013

An RPC adjustment is frequently used for distribution utilities and is among the most popular mechanisms. As part of a rate case, an RPC calculation is made for each relevant class. As illustrated in Table 2, after a period of time, the RPC is multiplied by the total number of customers in the relevant class to produce the revenue requirement. Thus the RPC takes into account not only the change in sales, but also the change in the number of customers, which impacts both sales and revenues required to serve the changed customer level. One of the benefits of an RPC mechanism is that customers do not end up compensating a utility for lost revenues from lost customers. The industrial customer class may have too few and too diverse customers for this method to work well.

Figure 3 illustrates how the type of utility and the type of costs included in the mechanism will influence the type of decoupling mechanism that should be considered.

Annual Review Decoupling (Also Known as Attrition Decoupling)

Under annual review decoupling, periodic reviews are used to adjust base rates for incremental and decremental known and measurable changes in rate base and operating expense. More controversial larger changes, such as major plant additions, are left for a full rate case (unless there is an applicable tracker in place, in which case it would not be part of the decoupling mechanism). An attrition adjustment (see text box below) is a useful solution to over-recovery of costs that can occur under a power adjustment clause.

K Factor

The K Factor is an adjustment used to increase or decrease overall growth in revenues between rate cases. It can vary from year to year but is usually set at a prescribed

Avoiding Double Recovery

A distribution and transmission decoupling mechanism will not address generation revenue changes for a vertically regulated utility. If generation investment-related costs are included in an RPC decoupling mechanism, there is a risk of double recovery of investment-related costs, because the customer count normally rises between rate cases, whereas the investment-related generation costs normally decline between rate cases, as existing power plants are depreciated. Rising fuel and purchased power costs will be recovered in a fuel adjustment mechanism, without the offset of declining investment-related costs, which would be captured in a general rate case. Thus, if regulators desire to retain a fuel adjustment mechanism under RPC decoupling (because utilities are altogether unwilling to bear such a broad fuel price volatility risk), it is important to have a properly designed power cost adjustment clause that accounts for changes in both investment-related costs and operating costs such as fuel. The power cost adjustment clause must be structured to take account of the normal decline in generation investment-related costs between rate cases to address this.

If sales go down, the vertically integrated utility will be able to avoid some costs (fuel or power costs, most notably), and the distribution-only utility may be able to avoid costs as well (although these would be expected to be small). The utility can reduce purchases of energy, reduce fuel usage in expensive marginal power plants, or sell excess generation into the market and avoid or recover part of (or more than) the revenues lost. To encourage the utility to obtain the best deal possible in its power supply management and off-system sales transactions, the regulator could allow the utility to keep a modest percentage of the off-system sales revenues sufficient to motivate profit-maximizing behavior. If these costs are managed with a fuel clause, they should be excluded from the decoupling mechanism.

For illustration purposes, for a typical utility, the costs established in a rate case are currently broken up more or less as shown in Table 3.

Table 3

Costs Established in a Rate Case

Costs	Amount	What it Covers
Base rates for power for vertically integrated utilities only	$0.04/kWh	Investment costs in power plants and transmission lines; non-fuel O&M for power plants and transmission lines
Base rates (delivery)	$0.04/kWh	Investment costs in distribution facilities; O&M for distribution facilities; all overhead costs (often including those attributable to power supply)
Fuel rate (subject to adjustment in the fuel adjustment clause [FAC]) – applicable to vertically integrated utilities	$0.02/kWh	All fuel and purchased power expense, net of sales for resale, plus transmission by others
Total rate to consumer	$0.10/kWh for vertically integrated utilities; $0.04 for distribution-only utilities	

level between rate cases. A K Factor coupled with an RPC can address the challenge of tracking the effects of cost drivers that are changing, while also using the convenient RPC device. This is because the K Factor is used to increase or decrease revenues between rate cases. The K Factor would reflect declining generation and transmission costs between rate cases, whereas the RPC would reflect rising customer counts and distribution costs.

The K Factor can be used if an important assumption is likely to vary in some meaningful way during the period the decoupling plan is in effect e.g., if average residential consumption is changing (either because of larger houses and associated growth in plug-in loads or because end-uses are getting more efficient) or PV growth is significant.

Hybrid

The hybrid mechanism is basically a combination of mechanisms that are used by a regulator. For example, a combination of RPC and K Factor may be used, so that the allowed RPC grows (or declines) according to a historical trend factor as the mix of customers changes over time.

2. Choosing the Frequency of Rate Cases to Determine Revenue Requirements

How frequently should the revenue requirement of a utility be reviewed? In some instances, regulators do not set a schedule for how frequently revenue requirements should be reviewed and instead leave it to the utility to decide when it needs to file for a full rate case review. This is the practice in New York.[32] The benefit of requiring a rate case review within a period of years is to capture any reductions or increases in utility costs that were not covered when the revenue requirement was established. A drawback of scheduled rate cases is the drain on resources resulting from a full rate case review if there has been little change. Additionally, from a consumer perspective, scheduled rate cases could mean the likelihood that rates will increase if the revenue adjustment mechanism does not account for inflation, or known and measureable increases in costs.

Most commissions have incorporated periodic reviews in their orders approving decoupling. Periodic reviews of the revenue requirement assure that underlying assumptions are still sufficiently valid to support rates and serve to assure that rates are in line with costs. For example, Wisconsin Public Service Corp. has annual rate cases with its decoupling mechanism.[33] Most decoupling mechanisms prescribe a specific multiyear duration and an expectation of a full "soup to nuts" rate case after a specific time with the understanding that the utility will not seek a rate case before the prescribed period. This approach can avoid significant financial and other costs associated with rate cases. Periodic reviews allow for adjustments to the revenue requirements to ensure that they accurately reflect the appropriate amount of revenue that the utility should collect as determined by the regulator.

Another approach is to build "mini rate cases" into the decoupling process as California and Hawaii regulators have done with the Pacific Gas and Electric (PG&E) and HECO decoupling programs, which resulted in abbreviated annual rate reviews and a triennial rate case, respectively.[34] We call this approach "annual review" decoupling, because it calls for reviews of changes in costs between rate cases, but not for re-litigation of issues such as rate of return, capital structure, or regulatory disallowances. It is also sometimes known as "attrition." These mechanisms can become fairly complex and require considerable attention (although less than a full rate case); however, they result in a more accurate accounting of what a utility's revenue requirements should be on an annual basis than does the reconciliation approach that is more typical.

Regulators value having precision in ratemaking to capture the major changes in the test year revenue requirements on an annual basis, and the multiyear mechanism should be expected to produce rates that approximate what annual rate cases would have produced. Naturally, in the absence of decoupling, rate adjustments (other than through separate riders) do not occur unless unless a rate case is adjudicated.

A "stay-out" provision, which prohibits utilities from filing a new rate case within some multi-year period, is a typical part of the decoupling package. A common exception to such a provision is to allow the utility to file in response to events that are outside its control.[35]

32 NY PSC. Docket Nos. 03-E-0640 and 06-G-0746. Order Requiring Proposals for Revenue Decoupling Mechanisms. April 20, 2007.

33 WI PSC, Docket No. 6690-UR-121. Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, 2012.

34 CPUC, Decision 93887, December 31, 1981; Hawaii Public Utilities Commission, Docket 2008-0274.

35 Stay-out provisions may not be legally enforceable; the utility always has the right to request an amendment to the stay-out provision, and the regulator always has the authority to grant that request.

3. Adjustments to Reflect Reduced Risk: Return on Equity/Capital Structure Benefits

Decoupling tends to reduce utility risk by providing revenue stability. How should utility risk factor into the decoupling mechanism? There are two mechanisms that can address this. The more common is to reduce the cost of equity, which translates into a lower return to the utility and saves customers money. The utility return on equity (ROE) is intended to compensate shareholders for risk, and capital markets interpret the message embedded in a state's ROE decision and other regulatory decisions. A second mechanism is for regulators to adjust the capital structure so as to increase the debt portion (for which a lower return is required) and decrease the equity portion (for which a higher return is required). Either mechanism returns benefits to the customer.

For decoupling to have its effect on capital markets, it needs to be allowed to work, and it needs to be perceived as part of the regulatory environment. For these reasons, its full potential may not be evident when a utility starts decoupling for the first time. Its effects are associated with whether the utility and the state appear (to financial market analysts) committed to decoupling, as well as how the state resolves other pressing regulatory matters. Regulators have tested methods to assess the appropriate ROE, and can use them after decoupling has taken effect to evaluate utility risk and the required ROE to maintain safe and reliable service.

Regulators may find that they want an ex ante reflection of the anticipated risk reduction from decoupling when the mechanism is approved. If regulators find that the risk of the firm calls for a reduced cost of capital, the regulator can choose to change the capital structure to require less equity. This change can be phased in during the life of the mechanism. Standard and Poor's has acknowledged that a utility with stable earnings will be able to maintain the same bond rating with less equity in its capital structure than a non-decoupled utility with more volatile earnings.[36] Equity is more costly to consumers, both because of the higher cost of equity and because of federal income tax treatment of utility equity. Because decoupling stabilizes the income stream to the utility (at least with respect to sales levels), it can provide this benefit of allowing a lower equity ratio. Rather than reduce the allowed return on equity, a step generally opposed by investor-owned utilities, regulators would simply adopt a slightly more leveraged capital structure, reflecting the lower earnings volatility. This produces economic benefits to consumers with no

Table 4

Illustration of Debt/Equity Ratio Shift

Without Decoupling	Ratio	Cost	Weighted with-tax cost of capital
Equity	48%	10%	7.38%
Debt	52%	7%	2.37%
Weighted cost			9.75%
Revenue requirement: $1 Billion Rate Base			$97,506.154
With Decoupling			
Equity	45%	10%	6.92%
Debt	55%	7%	2.5%
Weighted cost			9.43%
Revenue Requirement: $1 Billion Rate Base			$94,255,769
Savings Due to Decoupling Cost of Capital Benefit:			**$3,250,385**

adverse impact on utility shareholders. The shift in the debt/equity ratio as illustrated in Table 4 can translate into approximately $3 million in lower revenue requirements for every $1 billion of utility rate base, a 0.3-percent reduction. In Table 4, the reduced equity capitalization ratio produces about the same benefit to consumers as a 0.4-percent reduction in the allowed return on equity would produce, but without the adverse impact on shareholders.

D. Decoupling Adjustments: Select How To Handle Refunds Or Surcharges

1. Symmetry and Equity in Over- and Under-Recoveries

Decoupling mechanisms are designed to assure that actual revenues match authorized revenues during the life of the mechanism. Typically, however, actual revenues are either over or under authorized revenues. Decoupling

36 See: Standard and Poor's. (2004). *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines;* Moody's Investor Services. (2006). *Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings;* and Standard and Poor's. (2010, December 10). *Industry Report Card: U.S. Electric Utilities Well Positioned For 2011 Challenges.*

adjustments serve to correct actual revenues that are above or below the authorized revenue by either refunding revenue surplus or recovering revenue deficits. One of the key objectives of decoupling in the eyes of consumer representatives is a mechanism whose adjustments are symmetric, which is to say that over-collections are treated in the equivalent (but opposite) manner as under-collections (i.e., so that any over-recovery can flow back to consumers in the same way that any under-recovery is charged to them). Thus, if decoupling adjustments allow utilities to recover 100 percent of under-recovery, then adjustments should also refund ratepayers 100 percent of over-recovery. This contrasts with a lost revenue adjustment mechanism (LRAM), in which the utility gains recovery of additional margins from any increased sales, while also recovering hypothetical lost margins from the decreased sales resulting from programmatic energy efficiency. Under decoupling, the utility is entitled to its revenue requirement, nothing more and nothing less. This kind of outcome is the most common among decoupling mechanisms currently in force, but it bears mentioning here to ensure that symmetry in this form is included in formulating a decoupling mechanism.

2. Allocation and Rate Design of Over- and Under-Recoveries

The regulator must also decide how any over- or under-recoveries are allocated to customers. Some methods include:

- **Uniform surcharge (or credit) per kWh to all decoupled classes.** The total decoupled revenue requirement is computed on a consolidated basis for all classes; the excess or deficiency in revenue compared with revenue requirement is divided by total sales to produce a uniform $/kWh adjustment.
- **Uniform percentage surcharge (or credit) to all rate elements.** The total decoupled revenue requirement is computed on a consolidated basis for all classes; the excess or deficiency in revenue compared with revenue requirement is divided by the revenue requirement to produce a uniform percentage adjustment; that adjustment is then applied to each element of the rate design for each class of customers, including the customer charge, demand charge (if any), and energy charge(s).
- **Class-by-class decoupling.** The allowed revenue is computed separately for each customer class; the difference between actual revenue (by class) and allowed revenue (by class) is used to produce either a uniform $/kWh adjustment for all customers in that class, or a uniform percent adjustment to each rate element for all customers in that class.

a) Complementary Rate Design Considerations

The decoupling mechanism generally leaves rate design unaffected by applying either a uniform $/kWh or uniform percentage adjustment, but this need not be the only option. The mechanism can change rate design in the interest of complementing policy goals. The mechanism can reward customer classes in an inclining block rate by, for example, allocating any refund to the first block and applying surcharges to the tail block. This will apply to high-use customers, thereby sparing low-use customers of any additional rate increases from the mechanism.[37] There is likely some tolerance in the rate design for this approach, but it should be periodically reviewed and reset as necessary. In a business class with a three-part rate, rate changes can be channeled to the demand charge or the volumetric charge, depending on policy goals. Table 5, which comes from a Tucson Electric proposal some years ago, illustrates this point. Tucson had a seasonal inverted rate structure in which the summer rate was higher than the winter rate. Note that where there are homes on

Table 5

Using Rate Design and Decoupling Surcharges to Effect Policy Goals

	Summer	Winter	
Customer Charge	$7.00	$7.00	
First 500 kWh	$0.80	$0.073	Minus any decoupling credit
Next 2,500 kWh	$0.102	$0.093	Plus any decoupling surcharge
Over 3,000 kWh	$0.120	$0.113	Plus any decoupling surcharge

37 Studies have demonstrated a correlation between usage and income, such that low-income customers tend to use less than high-income customers. Colton, R. (2002, March). Energy Consumption and Expenditures by Low-Income Households. *Electricity Journal.* In current-day usage, this has a certain logic in that with the proliferation of a variety of electronic gadgets from cell phones to flat-screen televisions, it is the higher-income customers who can afford these more and in greater quantity.

Table 6

Decoupling and Rate Design: Surcharges On-Peak, Credits Off-Peak

Costs to Connect to the Grid	Charge	Decoupling Adjustment
Billing and collection	$4.00/month	None
Transformer demand charge	$1.00/kVa/month	None
Power Supply and Distribution: Bidirectional	**Charge**	**Decoupling Adjustment**
Off-peak	$0.07/kWh	Minus any decoupling credit
Mid-peak	$0.10/kWh	None
On-peak	$0.15/kWh	Plus any decoupling surcharge
Critical periods	$0.75/kWh	None

electric heating, it is important to design the rate so as to appropriately insulate all-electric homeowners from bearing more than a fair share of the decoupling surcharge during the winter heating months.

For customers on a time-of-use rate, the adjustment could work so that surcharges are applied to on-peak usage and credits on off-peak usage if this serves to make the resulting rates more cost based, as illustrated in Table 6.[38]

Thus, the allocation of costs associated with any credit or surcharge can be designed to complement other policy objectives embedded in the rate design. Depending on whether rates are on an inclining or time-of-use basis, the reconciliation could be designed in a fashion so as to encourage customers to use energy more efficiently and/or to discourage on-peak usage.

Another option is to evenly allocate surcharges and refunds across the first block of usage so all customers pay and benefit equally, irrespective of how much and when they consume electricity. This is how Idaho Power and Light allocates the adjustments.[39]

A more general discussion of the relationship between rate design and decoupling can be found in Section III B.

3. Adjustment through Base Rates or a Purpose-built Rider

During a decoupling plan, base rates can be adjusted or a specific rider can manage the changes. As discussed in this paper, a rider is an adjustment to base rates that gets rolled into the total rate a customer pays. It is not a surcharge that appears on a bill.[40] Unless there is a statute in place authorizing recoveries through a specific mechanism,[41] regulators normally have the discretion to decide this issue. A factor in the decision may be the revenue adjustment mechanism chosen. For example, if the adjustment mechanism requires annual mini rate cases, the commission may opt to fold any adjustments into the rate case rather than into a separate rider. Conversely, if there is no mandate for frequent rate cases, a rider may be a more practical approach to reconcile any adjustments.

4. Frequency of True-Ups

Regulators can decide the frequency of the revenue reconciliation. The typical choices are monthly, quarterly, and annually, although any option can work within these boundaries. Monthly reconciliation is the lower limit, because billing is monthly, whereas annual reconciliation is the upper limit to avoid excessive divergence between expected and actual revenues.

More frequent adjustments minimize the divergence between actual and authorized revenues; however, it can expose consumers to volatility from such factors as swings in weather that can cause unusually high or low revenues unless a cap is used (see Section 5 for a discussion of caps).[42] For example, Baltimore Gas and Electric Company

38 The rate design in this illustration comes from Lazar, J., & Gonzalez, W. (2015). *Smart Rate Design for a Smart Future.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future. The authors have added to that the column on rate adjustments.

39 Idaho Public Utilities Commission, IPC-E-04-15 – Idaho Power – Investigation of Financial Disincentives.

40 Rolling the rider adjustments into base rates is done to minimize bill complexity (see the section on Bill Simplification).

41 A state may have a prohibition from adjusting base rates outside of a full revenue requirement investigation, but this may allow for an adjustment of a rider in a decoupling mechanism.

42 An argument against decoupling and in favor of straight fixed/variable rates is that calculating the adjustment to rates is complex and a lot of work. The fact that some utilities do so monthly belies this concern.

reconciles rates monthly, but caps the size of a monthly adjustment at ten percent, with anything above that being carried over to the next period for reconciliation.[43] Month-to-month sales variations may tend to balance out over time.

The advantage of monthly adjustments is that they have the effect of moderating the impacts of significant and unusual factors, such as extreme weather, on utility bills. In a very cold winter month or a very warm summer month, usage tends to increase. Under such circumstances, decoupling reduces the price per unit, thereby mitigating the bill impact. Conversely, in winter or summer months with unusually mild weather, customers tend to use less energy. Decoupling raises the rate at a time when bills are more affordable because customer usage is down. The vast majority of limited decoupling mechanisms that address

Weather-Only Normalization as a Real-Time Decoupling Adjustment

Weather variation accounts for the vast majority of deviation in utility sales compared with the assumptions made in general rate cases. Rate cases use weather normalization (typically a 20- to 40-year average) to determine base rates. Between rate cases, sales vary because of weather, conservation, economic conditions, the deployment of DERs, and other factors. But weather is probably the largest of these, responsible for perhaps 80 percent of decoupling cost deferrals.[44]

More than 40 natural gas utilities have weather normalization mechanisms in place to adjust their rates to reflect weather conditions that vary from the "normalized" weather data. Weather normalization is a form of limited decoupling.[45] It protects utility earnings from sales variations from one cause (weather) but not from other causes (conservation, business cycles, DERs). For most of these, the adjustments operate within the billing cycle, meaning rates are adjusted daily for sales variations attributable to weather. This has been mechanical in nature and generally well received by regulators and consumers.

For both electric and natural gas companies, weather normalization is a component of determining the pro forma revenue requirement used by regulators in rate cases. For gas utilities, it is tied to the heating degree-days; for electric utilities, it is affected by both heating degree-days and cooling degree-days.

Because the adjustment in sales volume is directly tied to factors that can be measured on a daily basis (temperature), it is possible for an adjustment mechanism to operate within the utility billing cycle, meaning costs do not need to be deferred for later recovery. If the rate case weather normalization calculation determines that sales vary by 1,000 MWh for each cooling degree-day, and a given billing cycle has 30 fewer (or more) cooling degree-days than the long-term average used in the rate case, the allowed margin would change by 30,000 MWh multiplied by the base cost per kWh included in rates. The next billing cycle (typically starting and ending one day later) might be 29 or 31 degree-days different from the average. The same arithmetic would apply.

It would be relatively straightforward to establish a decoupling mechanism that had two components:

a) Weather normalization, completed within each billing cycle; and
b) Deferral decoupling for all other variations in sales, calculated annually.

In this approach, customers would see immediate changes in rates each billing cycle to reflect the difference in weather compared with the baseline. The benefit of this for consumers is that rates would go down when usage (and bills) go up, so sharp bill increases would be moderated. The benefits of this for utilities is that rates would go up when usage (and bills) go down, so earnings are stabilized, allowing a more leveraged and lower-cost capital structure that ultimately saves consumers money.

43 BGE. (2007, October 26). Filing 102607F; Maryland Public Service Commission.

44 In reviewing the material in the report *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations* by Pamela Morgan, Graceful Systems, LLC, it appears that for natural gas utilities, decoupling adjustments have been 49 percent surcharges and 51 percent credits, whereas for electric utilities, it is more like 34 percent credits and 66 percent surcharges. Gas utilities are much more weather-dependent (two-thirds of their sales are for space heat). Id. December, 2012.

45 See definitions for full, limited, and partial decoupling in *Revenue Regulation and Decoupling* (2011), pp11–13.

only weather are gas utility decoupling mechanisms. They typically operate on a monthly basis.[46]

a) Accrual or Current Method for Rate Adjustments

Although all monthly mechanisms determine a varying month-by-month allowed revenue requirement, there are two approaches to the monthly adjustment. In one, the billing information is collected and processed, and the rate is changed for the next month. The customer is given notice of the rate change. By this method, for example, January's usage will affect March's rate. Over- and under-collections are accrued (although for a much shorter period than an annual adjustment) and this is known as the "accrual method." In the other, the billing information is collected and the rate is changed to apply retroactively to the usage from that month. In this method, January's usage will affect January's rate. This approach allows very accurate utility revenue collection and is known as the "current method."

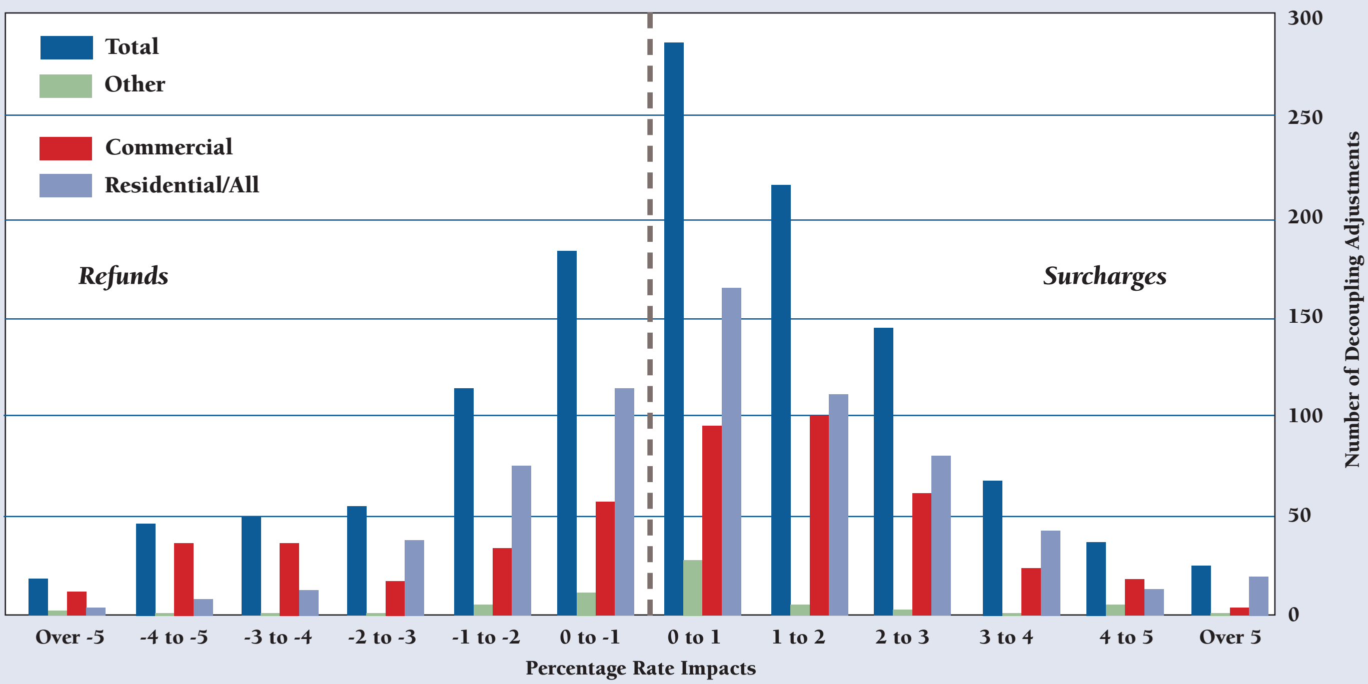
A longer period, such as a year, has the benefit of smoothing out shorter-term volatility and tends to result in smaller adjustments—positive or negative—overall, but is less accurate on a timescale basis in matching actual and authorized revenues. A longer period between reconciliations also creates a greater mismatch between the prices being paid in a period and the long-run marginal cost of service in that period (because the rates are adjusted for last year's revenue shortfalls or overages, which are different from today's long-run marginal cost). Where true-ups occur annually, the creation of a balancing account to track surpluses and deficits, and a cap to manage exceptional volatility, are typical.

5. Caps on the Size of Decoupling Adjustments

Although reconciliation adjustments resulting from a revenue adjustment mechanism tend to cluster in the –2 to +3 percent range, they can be larger or smaller, as either a surcharge or credit.[47] Figure 4 shows the experience with decoupling rate adjustments. Regulators and consumer

Figure 4

Changes in Rates From Decoupling Mechanisms 2005 to 2011[48]



46 Black and Veatch compiles a list of gas utilities with weather normalization mechanisms; this is a form of limited decoupling. As of November 2015, they listed 64 mechanisms in 26 states. The majority of these operate in "real time," meaning within the customer billing cycle.

47 See Figure 3.

48 Morgan, P., (2013). *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations.* Retrieved from: www.raponline.org

advocates may be concerned about large increases resulting from decoupling. This concern is heightened for consumer advocates if the tariff permits pancaking of multiple adjustments to the revenue requirement via riders in addition to decoupling, as discussed in Section 6. Many regulators adhere to the regulatory principle of gradualism in that rate increases are modulated so as to not create rate shock and so that consumers can adjust to the new prices. A rate cap can manage customer expectations and impacts.

Not all utilities with decoupling mechanisms have caps on the magnitude of annual adjustments. Some regulators may not be fans of deferrals and may instead prefer to allow the true-up to reflect the full extent of any adjustment and avoid carrying costs that may be imposed by limiting the amount of the credit or surcharge. Some have limited surcharges, but allowed full flow-through of credits.

For those who prefer to limit the rate impacts, there are various mechanisms for capping rates. One often used is a cap on the percentage of a permissible rate change. For example, Idaho Power and Light caps the change at a plus-or-minus three percent, with any excess carried over to the next year.[49] Another is a cap on total revenue increases (as opposed to rate increases), as was ordered by the Massachusetts Department of Utilities and used by National Grid in Massachusetts, which has a one-percent revenue cap.[50] Still another mechanism is to set the cap in dollars, not as a percentage. This in fact is how the Wisconsin Public Service Commission (PSC) has capped Wisconsin Public Service Corporation's annual decoupling adjustments: they are constrained to $14 million.[51]

Setting the amount of the cap, whether it is a percentage increase or another mechanism, will depend on the stakeholders' and ultimately the regulator's view of the amount of the change in rate the public and the utility (if the adjustment is a credit to customers) can tolerate. It can range from very small to a higher amount and may depend on the level of existing rates, if they are comparatively high or low, and what other rate impacts are on the horizon. For example, if a regulator knows that a utility is about to request cost recovery for new investments, that could figure into a decision to regulate how much of an increase customers must absorb and under what timeline. The rate of general inflation may influence this choice.

If a cap is imposed, there is the issue of what happens to the unrecovered amounts. Mostly this question revolves around the time period for the deferral and how deferral balances are handled (Section E6). If in the next reconciliation period the utility does not hit the same cap, then it is an easy matter to allow the unrecovered amounts to be folded into the subsequent period's true-up. However, if there are several sequential cycles of exceeding the cap, the issue becomes more complex, especially with carrying costs over multiple periods. Should this be a concern, there may be a desire to place a timeframe of several years over which under- or over-recoveries may be permissible. This decision should be made with awareness of the risk implications.

Carryovers can range from one to several years to however long it takes to get full recovery. It is worth noting that to date the issue of carryovers has hardly arisen. It is mentioned merely as a factor to consider when designing a complete decoupling mechanism to ensure that all the elements fit together and work to accomplish the goal of the regulator.

The size of the cap and the chosen revenue adjustment mechanism are related by the resulting magnitude of rate impacts.

6. Carrying Charges for Decoupling Deferrals

With the exception of decoupling mechanisms that adjust rates monthly, under decoupling, the utility is either carrying a deferred balance for collection or refund to customers.[52] There are two instances in which carrying charges could be considered. The first is if the reconciliation or true-up of charges occurs over an interval, such as a year, so that a portion of the accumulated true-up amount remains unrecovered between reconciliation

49 Lazar, J. (2013). *The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power* (Appendix D of *Smart Rate Design* for a Smart Future). Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/the-specter-of-straight-fixedvariable-rate-designs-and-the-exercise-of-monopoly-power

50 Id. Note that National Grid also has annual mini rate cases to adjust rates.

51 Morgan, P. (2013)..

52 Even in the case of current method decoupling (see p26), a balancing account may be needed if the cap is invoked in a month of extreme volatility.

periods. The second is if there is a cap on the size of the reconciliation adjustment permitted in any given adjustment period (see Section E5) and the unrecovered portion of the adjustment is carried over for the subsequent time period. Regulators will need to decide if carrying costs should apply to one or both instances.

If they are applied, then logically, assuming a symmetric approach to over- and under-recoveries, the carrying charges should attach equally in both directions. Although applying carrying charges will more accurately compensate the party who is entitled to a refund, it does add a modest level of complexity to the calculation of refunds.

Where carrying charges are applied, the next question is how much should they be. Because the mechanism tends to roll forward administratively, there is generally no risk to deferred balances, so a risk-free rate is appropriate. Options include the utility's short-term debt rate or the customer deposit rate; however, regulators are free to choose whatever rate they believe is reasonable. Unless it is expected that there will be a permanent deferral, or if some atypical risk is attached to the reconciliation process, the utility will not require permanent financing for the deferrals, so the weighted cost of long-term debt and permanent equity financing is unlikely to be the appropriate capital source to cover the deferral amounts.

III. Additional Considerations

Revenue regulation does not need to be accompanied by other policies and can be implemented on a stand-alone basis. However, consideration of some of the implications of decoupling in terms of benefits to the utilities, policy goals, and rate designs may result in regulators making certain decisions with regard to complementary policies and the conditions for decoupling.

A. Performance Evaluation System Applied to Decoupling

Decoupling is sometimes associated with performance- or outcome-based regulation. Why is that? If the utility is no longer worried about sales because the throughput incentive is neutralized, management is then ready for a positive message from government about priorities conveyed in the form of goals and financial incentives that promote excellence and innovation. There is also a pragmatic reason: the periodic rate reconciliation provides a coincident opportunity to apply rewards and penalties to utility rates based on utility performance.

Some believe that the performance system is a distraction and that utilities should perform with excellence without the need for rewards, and that the existing powers of regulation provide penalties for poor performance. They suggest that decoupling should strictly govern the recovery of costs already incurred. Decoupling under any regulatory paradigm is a distinct issue from performance metrics.[53]

B. Rate Design

Rate design has emerged as a major discussion point in regulation. As energy efficiency deployment grows and the cost of customer-sided alternatives like rooftop photovoltaic (PV) continue to decline, there is a growing debate over how the utilities collect their revenues from more diverse

Table 7a

Example of an Electric Bill That Lists All Adjustments to a Customer's Bill

Your Usage: 1,266 kWh

Base Rate	Rate	Usage	Amount
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:			$139.74
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

Table 7b

The Rate Above, With All of the Surcharges, Credits, and Taxes Applied To Each of the Usage-Related Components of the Rate Design

Base Rate	Rate	Usage	Amount
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

53 For a detailed discussion of how performance-based regulation can work hand-in-hand with decoupling, see Lazar, J. (2014). *Performance Based Regulation for EU Electric Distribution Utilities.* Retrieved from: http://www.raponline.org

customers and how customers should be compensated for what they produce.

Decoupling is a tool that regulators can use to manage utility revenue adequacy, leaving the focus of rate design on customer price signals and other policy priorities. Price signals are increasingly important with customers, especially mass market customers, making more energy investments than ever before. By combining aggressive deployment of cost-effective energy efficiency and distributed energy resources without disrupting revenue adequacy, total consumer power costs can be reduced. And, by also reducing the risk of insufficient revenue recovery by the utility, reliable service supported by reasonably priced capital can be assured.

If a regulator has ordered the utility to adopt decoupling, the need for high fixed charges or demand charges becomes inconsequential to shareholder earnings, because at least in the short-term, the utility has a greater ability to recover its revenue requirement, assuming it has acted reasonably and prudently. Other longer-term tools need to be explored to further ensure that long-term utility revenue requirements and pursuit of public interest objectives are met in the most efficacious way.

C. Bill Simplification

Decoupling requires periodic adjustments in customer rates. It is important for the rates, as they appear on the customer bill, to be understandable to the customer. Many utilities' bills include separately stated line items for various charges, usually linked to specific tariff riders; this is undesirable for many reasons, of which customer confusion is the most important.

Table 7a shows how some bills would appear with itemization of five tariff riders (of which decoupling is one), plus two taxes. Below that in Table 7b is the "effective rate" that customers would actually pay. It is essential that bills show just the effective rate, which includes all surcharges, credits, and taxes, so that customers understand how much they will save if they use less electricity, and how much they will pay if they use more electricity. Having multiple charges on a bill makes doing such a calculation more difficult for the customer.

IV. Summary of Potential Pathways

Table 8, on the following page, is a summary of the elements described previously. In designing a decoupling mechanism, regulators may want to consider each of these categories of elements and decide, for each, which option works best. There will be some natural flow of decisions once certain elements are chosen. However, for the most part each element is independent of the others.

Table 8

Summary of Potential Elements

Element	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Function	Distribution	Distribution and transmission	All functions				
Customer Class	Residential and small commercial	All but large industrial	All classes				
Excluded Costs	Costs in riders	Riders plus production costs	All variable costs	Other			
Rate Case Frequency	No requirement	Annually	Every 3 to 5 years	Mini rate cases	Every 4 to 7 years	Other	
How Established	Negotiations in rate case	Statute	Rulemaking	Commission order			
RAM	None	Stair-step	Indexing	RPC	Annual review decoupling	K Factor	Hybrid
Symmetry	Yes	No					
Recovery Allocation	Across the board equally	Customer class contribution	Credit in first block	Surcharge in last block	Combination between options 1 and 4	Other, such as judgments on which rate elements receive surcharges and credits and which do not	Other
How Recovered	Rate case	Rider					
Frequency of True-Ups	Annually	Quarterly	Monthly	Other			
Carrying Costs	No	Yes, short-term debt	Yes, customer deposit	Yes, other			
Cap Methodology[54]	None	Percentage rate increase	Percentage revenue increase	Dollar amount	Other		
Regulatory Conditions	None	Energy efficiency requirement	Customer service	Distributed generation interconnection	Other		
Rate Design	Maintain customer connection-based fixed charge	Coupled with inclining block	Coupled with time-of-use	Combination	Other		
Rate of Return	No adjustment (wait for effects to play out)	ROE reduction ex ante	Capital structure adjustment ex ante	Other			
Performance Metrics	Applied to decoupling	Not applied	Negative only	Positive and negative			

54 Note that for the cap methodology, there is also the question of how much. On a percentage increase basis, for example, the range could be one to three percent.

V. Representative Pathways: Straw Scenarios

From among all of these options, RAP has put together for consideration three scenarios that include the major elements of decoupling.

Scenario 1 applies to a distribution-only utility or a vertically integrated electric utility that has adopted decoupling for distribution services only. In this example, the decoupling is only being applied to residential and small commercial customers. One reason for this not applying to larger customers could be because of the presence of an industrial opt-out program and because there are too few industrial customers who are not under a special contract with the utility. In this scenario, as in all the scenarios, distribution-related tariff riders are excluded because those costs are being recovered elsewhere, outside of base rates. The revenue adjustment mechanism is an RPC mechanism, which is currently widely in use. A K Factor is used with this mechanism to adjust for increases and decreases in the growth in revenues per customer. As with all the decoupling scenarios below, this one requires symmetry to ensure fairness in the treatment of over- and under-collections. There is no requirement to file a rate case in this scenario. There are pros and cons to this, and the commission could decide either way on this point. As the revenue decoupling mechanism applies only to small residential and commercial customers, a simple mechanism of applying adjustments across the board to residential and small commercial customers was chosen; however, an allocation based on customer class contribution to total revenues could also be used.

This scenario differs from the others in that it has a monthly true-up recovered through a rider. As a result, there are no carrying costs, but rates are subject to larger monthly fluctuations that may be necessary to explain to customers. There is a ten-percent cap on the size of the monthly adjustment, which is larger than what would be expected in an annual true-up, because the revenue swings can be larger over shorter periods of time, without the benefit of a longer period to smooth out anomalies. Amounts exceeding the cap would be carried over to the following month, and because of the short duration, as noted previously, no carrying charges would apply. A regulatory condition that would be required as a condition of decoupling would include the utility's compliance with energy efficiency programs and other distributed energy resource programs, along with meeting customer service quality standards. This would help provide assurance to customers that the utility will meet its commitments to embark on cost-effective programs and good customer service.

In this scenario, the assumption is made that the utility has inclining block rates—an assumption made for all of the scenarios, as that is the most common rate design and better aligns cost with causation than would flat rates or declining block rates. With this rate design, as a further conservation inducement for customers, credits are provided in the first block, benefiting all customers, but surcharges are allocated to the higher-use customers in the second block.

In Scenario 1 under Performance, we added a performance metric for customer care and reliability. Although a performance metric is not integral to a decoupling mechanism (which is the reason for its absence from Scenarios 2 and 3), it is certainly worthy of consideration. Changing the utility mindset through rewards and penalties toward a customer-service-driven approach that can still benefit shareholders is a better direction for the future.

Across the board, there is no adjustment in any scenario to the ROE. ROE adjustments are poorly received by the utility and the investment communities and could contribute to an investment downgrading that then could increase the cost of borrowing—a cost passed on to consumers. A better way to reflect the reduction in risk is through a change in the capital structure that reduces the equity ratio. Because equity is more costly to consumers than debt, reducing the ratio of equity to debt can save customers money without jeopardizing the utility's ratings.

Scenario 2 is similar to Scenario 1 in that it applies to the distribution function only. A distinguishing factor, however, is that this decoupling mechanism applies to all customer classes, including industrial. In this case, as in Scenario 3, there are a significant number of industrial customers to warrant their inclusion in the decoupling mechanism. This scenario includes a requirement to have a full rate case every three to five years. (The regulator can decide the frequency with which it is comfortable.) No revenue adjustment mechanism is used; the utility would be required to file a rate case to adjust the revenue requirement. Consumer advocates may prefer no revenue adjustments between cases, so that was represented in this scenario. In the interim between rate cases, the utility would charge or credit customers through a rider for any differences between actual revenues and authorized revenues. The amount of the rider would be set annually, based on the preceding year. As discussed in Scenario 1, all distribution-related tariff riders would be excluded and the application of the decoupling rider would be symmetric. Because of the applicability of the decoupling mechanism to all customer classes, the surcharges and credits would be

Table 9

Representative Pathways: Three Straw Scenarios

Element	Scenario 1	Scenario 2	Scenario 3
Applicability	Retail choice or VIEU*	Retail choice or VIEU	VIEU
Function	Distribution	Distribution	Distribution and generation
Customer Class	Residential and small commercial	Residential, commercial, and industrial	Residential, commercial, and industrial
Excluded Costs	All distribution-related tariff riders	All distribution-related tariff riders	All costs addressed by tariff riders
Rate Case Frequency	No requirement	Full scale every 3 to 5 years	Annual mini rate case
Revenue Adjustment	RPC with K Factor	No RAM	Annual review decoupling
Symmetry	Yes	Yes	Yes
Recovery Allocation	Across the board to residential and small commercial	Customer class contribution to total revenue defines amount for each class	Customer class contribution to total revenue defines amount for each class
How Recovered	Rider	Rider	Base rates
Frequency of True-Ups	Monthly	Annually	Monthly
Carrying Costs	No	Yes	Yes
Caps	10% rate difference	3% rate difference	No cap
Regulatory Conditions	Energy efficiency programs, customer service quality, and other distributed energy resource programs	Energy efficiency programs, distributed energy resources, and customer service quality	Energy efficiency programs, distributed energy resources, and customer service quality
Rate Design and Allocation of Reconciliation	Inclining block; credits on first block; surcharge on second block	IInclining block; credit on first block; surcharge on second block; *or* time-of-use; refund on off-peak; surcharge on on-peak	Inclining block; credit on first block; surcharge on second block; *or* time-of-use; refund on off-peak; surcharge on on-peak
Return on Equity	No change	No change	No change
Capital Structure	Reduce equity ratio	Reduce equity ratio	Reduce equity ratio within annual review

** VIEU: vertically integrated electric utility.*

allocated based on the customer class contribution to total revenue.

Because a rider is deployed and is adjusted annually with a cap on rate increases of three percent, carrying charges are applied to both the amounts being held for recovery or credit during the course of the year, and to any amounts exceeding the three-percent rate differential that are carried over to the next year. A modest and reasonable rate used is this scenario is the customer deposit rate. This scenario also requires a utility commitment to energy efficiency, distributed energy resources, and customer service quality. The rate allocation is the same as discussed in Scenario 1. This scenario rejects a reduction on the ROE in favor of a reduction in the equity portion of the capital structure.

Scenario 3 differs from the first two scenarios in that it applies to a vertically integrated utility and to its distribution and generation functions. All customer classes are included in this scenario, and therefore the allocation of surcharges or credits is based on class contributions to total revenues. This scenario uses an annual revenue decoupling mechanism in which all tariff riders and costs addressed by the tariff riders are excluded to avoid any risk of over-recovery of certain production-related and other costs. Unlike Scenarios 1 and 2, which rely on riders to recoup over- and under-recoveries, Scenario 3 requires annual mini rate cases to adjust revenues and reconcile rates with revenue requirements. This is consistent with choosing an annual revenue decoupling mechanism that calls for periodic reviews and adjustments to base rates for incremental and decremental known and measurable changes to base rates. As with the other scenarios, symmetry in terms of over- and under-recoveries is applied. A carrying charge based on the customer deposit rate is used, and because new revenue requirements are established annually in the mini rate case, no cap is applied. This mechanism is contingent on the utility engaging in energy efficiency, DER, and providing quality customer service. No adjustment to the ROE is applied; instead a reduction in the equity ratio is recommended. Finally, the rate design is the same as that reflected in Scenarios 1 and 2, with the addition that, if a time-of-use rate is in place, the credit should apply to off-peak usage and the surcharge to on-peak usage.

VI. Conclusions

When industry people gather and talk about decoupling, one might hear a wide range of views from support to skepticism. Everyone has their own perception of what decoupling is and what it does that is foundational to their view. On a macro level, decoupling separates sales from revenue. However, on a micro level, there are myriad details in how that is done that influence people's viewpoints. Often these details are assumed and not expressed, and it is easy for a conversation about decoupling to result in talking past each other for lack of clarifying foundational assumptions. Decoupling is not one thing, but a vehicle with many, many options.

In understanding decoupling, perhaps one should start with an understanding of what is being assumed about decoupling and how it works. Which attributes are viewed favorably and which are viewed unfavorably, and why? For an unacceptable attribute, is there an option that works better? Is there room in a negotiation on decoupling to find solutions to stakeholders' most serious concerns and develop a consensus mechanism that everyone can accept?

In this paper, a number of decision paths to designing decoupling have been discussed. Regulators and stakeholders can choose among the options to find the path that works best for their jurisdiction. Although there are a number of variables, there are certain pathways that RAP would recommend over others. They include:

- The decoupling mechanism should be symmetric so that over- and under-recoveries are charged or credited. This is basic fairness.
- All costs recovered through a separate tariff rider should be excluded from the decoupling mechanism to avoid over-collection of costs.
- In lieu of an ROE adjustment to reflect lower risk, a reduction in the equity ratio should be considered instead, as that will save customers money without the adverse impacts on a utility's financial picture that a reduction in the ROE would engender.
- Regulatory requirements of performance should be a condition of decoupling such that: (1) the utility engages in energy efficiency at the prescribed level, (2) the utility assists in the development of distributed energy resources, and (3) the utility provides quality service to the customer at the levels dictated by regulators.

Other factors vary by jurisdiction and need to be decided as well:

- Perhaps the most critical decision is which revenue adjustment mechanism to use. Although all have their pros and cons and have been put in place in various jurisdictions, RAP chose two mechanisms for distribution-only decoupling and a third for vertically integrated utilities. RAP chose an RPC approach with a K Factor for one of the examples, because RPCs allow the revenues to be adjusted based on the number of actual customers, which will reflect increases or decreases in the cost to serve. To that, a K Factor was added to reflect growth in revenues between rate cases. The size of the K Factor is another decision point that can impact the frequency with which a utility might need to apply for a rate increase. The other option is no revenue adjustment mechanism. The revenues are as authorized in the last rate case and any change has to be accomplished through a rate case. Finally, for the vertically integrated utility, an annual review decoupling mechanism is the best option to ensure there is no over-collection of production costs. With an annual review decoupling mechanism, as the name implies, comes annual reviews with mini rate case adjustments to the revenue requirement. The frequency of rate cases is another variable in terms of whether the regulator or the stakeholders in the process want to agree on the frequency of rate cases or just let the utility decide when it needs to file a rate case application.
- The allocation of costs by customer class is another variable. If the decoupling mechanism is only

applying to residential and small commercial customers, it may be simpler and easier to just apply the adjustments across all customers. A more precise way to do it, which is recommended if all customer classes are involved, is to allocate the adjustment based on the customer classes' percentage contribution to total revenues.

- The mechanism for recovery of the adjustments and the frequency are also variable. If the annual review decoupling mechanism is used, it makes sense then to roll any adjustment into the base rates, as they are reset annually. For other revenue adjustment mechanisms, a separate rider is an option, including how frequently to reconcile the over- and under-recoveries, whether it is monthly, annually, or over another period of time.
- Caps on the amount of variation in rates, up or down, are another decision point. Caps are used to moderate the amount of fluctuation in rates to which customers or the utility may be subject from year to year, between rate cases.
- Carrying costs, in terms of whether to have them and at what rate is another decision, including to what they may be applied. Are they applied every month when adjustments are made annually, or are they only applied if there is an amount that exceeds the cap? The size of the carrying cost will also impact the size of the rate adjustment.

This paper has unpacked how to do decoupling. Each choice means something about what decision-makers prioritize and what managers are willing to change. It aspires to make conversations about decoupling and related issues as informed and constructive as possible. There is no one answer for the question, "How should this utility decouple revenues from sales?" For each company, state, and time, the answer should represent the priorities of the day, guided by the framework laid out here.

Decoupling can be applied to any utility. Although it may be a more obvious option for a regulated utility, it can also be applied to municipal utilities (munis) and co-operatives (co-ops). They equally have a need to ensure adequate revenues while implementing energy efficiency and other policies that result in lower costs for the system in the long-run and are better for the environment. The difference with munis and co-ops is that, because these systems are owned by the government or the customers themselves, respectively, there is no need to include performance incentives as part of the decoupling mechanism. The decoupling design decisions may be different for these entities as well. For example, in addition to not needing to address performance measurements, the ROE considerations would not be necessary. Nor might it be necessary to require rate cases at any interval to adjust rates downward for any rate changes, as it would be more likely that these would be done as a matter of course, because there are no shareholders to answer to.

Ultimately, a good decoupling mechanism that will work in a jurisdiction may best be driven by a consensus among the stakeholders in a case or collaborative process in which the mechanism chosen and the decisions made balance the interests of all parties.

VII. Appendix: The Benefits of Decoupling

Under traditional regulation, utility companies ensure their financial health and earn a profit by investing in assets (plant in service) on which they can earn a return, increasing sales within the capability of existing assets or decreasing their costs. The profit incentive to increase sales when revenues are determined solely by sales is known as the "throughput incentive."

Decoupling addresses the throughput incentive by breaking the link between sales and revenues, thereby removing utility management emphasis on sales. This is significant because utilities, like most businesses, view their core goal as selling product to make money. Making the utility indifferent to changes in sales paves the way for utilities to support consumer energy self-reliance and to deploy cost-effective energy efficiency on the customer's side of the meter. Decoupling allows management to focus on what customers care most about—service and cost control—which benefits all customers. As the regulatory paradigm shifts more toward customer participation and control in energy decisions, decoupling helps shift corporate thinking in a direction that is more compatible with consumer interests.

If the underlying costs are not changing quickly and significantly and the main reason for revenue deficiencies is attributable to the deployment of distributed energy resource (DER) options, then decoupling could be a good solution to address those changes. However, if costs are changing significantly and quickly and due to factors other than DER or, if because of the size of the revenue deficiency, it is difficult to design a decoupling mechanism, then annual rate cases (while avoiding pancaking of rates) may be an option.

A frequently misunderstood aspect of decoupling is the belief that decoupling also removes the incentive for the utility to be more efficient and lower its costs. Decoupling does not adversely impact the incentive for utilities to be efficient, because the utility has regulatory confidence that, assuming it acts reasonably and prudently, it will obtain its authorized revenue requirement. Thus, if expenses are decreased by the utility's efforts to lower its costs, this could translate into higher returns for shareholders because the difference between revenues and operating costs has increased. Table 10 illustrates this point, in which the utility's return is based on the difference between the authorized revenue requirement and all operating and maintenance expenses. Two scenarios are shown: one in which the utility maintains the status quo and one in which the utility acts to achieve efficiencies for its company.

Table 10

Illustration of Status Quo vs. Cost-Efficient Efforts

	Revenues	Costs	Earnings
Status Quo	100	90	10
Cost-Efficient Efforts	100	88	12

Thus, decoupling does not minimize the incentive for utilities to manage their companies well and to be good stewards any more than the absence of decoupling does. In fact, it could well increase the incentive to operate efficiently because it provides a means to increase net income. The only impact that decoupling has on how a utility operates is to remove the relationship between sales and earnings. In the long run, growth in sales could result in increased investments in generation, transmission, and distribution that will raise revenue requirements and rates.[55] On the other hand, a focus on net income can increase operational efficiency.

55 For vertically integrated states, the increased cost of new capacity additions is passed on to the consumers by their incumbent utility. In restructured states, the demand for capacity will raise rates and the marginal cost of that capacity is likely to be greater than the embedded cost of the existing generation.

Of all the available resource options, cost-effective energy efficiency is almost always least cost[56] and plentiful.[57] However, of all the resource options, energy efficiency is the only one for which utilities generally earn zero return on investment and also face the financial risk of reduced sales, reduced revenues, and reduced earnings.[58] There is little argument in most quarters that energy efficiency has value for the consumer and for society as a whole.[59]

If we accept the premise that energy efficiency benefits society, then it is important to develop this resource in a manner that does not hinder the utility's ability to complete its mission and maintain its financial health. Moreover, to make energy efficiency as successful as possible, policymakers have a stake in seeing utilities embrace it wholeheartedly. Decoupling removes the utility disincentive to engage in making energy efficiency a part of its portfolio.[60]

Regulators have considered and adopted several options for addressing utility net lost revenues. They include decoupling, lost revenue adjustment mechanisms (LRAMs), and higher fixed customer charges. A few words of comparison of these mechanisms are appropriate here to understand why RAP views decoupling as the superior mechanism.

Lost Revenue Adjustment Mechanism. A formula that computes the amount of net lost distribution revenue that occurs as a result of reductions in usage owing to programmatic energy efficiency and allows subsequent surcharges to recover this lost revenue.

Revenue Regulation (Decoupling). A mechanism that relies on a utility's allowed distribution service revenue requirement and allows surcharges or credits, if actual sales are lower or greater than projected sales, to address under- or over-collections.

Higher Fixed Charges. A rate design that collects a larger portion of the utility distribution revenue requirement in monthly fixed charges that do not vary with usage. One example is the straight fixed/variable (SFV) rate design, which is intended to recover 100 percent of the distribution and often transmission revenue requirement in monthly fixed charges.

56 Lazard. (2014). *Lazard's Levelized Cost of Energy Analysis – Version 8.0.* Retrieved from: https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf

57 Neme, C., & Grevatt, J. (2016). *The Next Quantum Leap in Energy Efficiency: Getting to 30 Percent in Ten Years.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/the-next-quantum-leap-in-efficiency-30-percent-electric-savings-in-ten-years/

58 Utilities earn a return on investment in plant. However, for energy efficiency, unless an incentive payment is included, utilities will not earn a return. Even when they do, it is usually less in actual dollars for energy efficiency than it may be in capital investments.

59 For an in-depth discussion of the utility, participant, and societal value of energy efficiency, see Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency; see also United States Environmental Protection Agency. (2015). *The National Action Plan for Energy Efficiency,* Retrieved from: https://www.epa.gov/sites/production/files/2015-08/documents/vision.pdf

60 Although decoupling removes the utility disincentive to do energy efficiency, it does not create an incentive by giving the utility an opportunity to earn a return in the way that investment in physical plant does. Therefore, many regulators have put in place various incentive mechanisms to encourage greater participation by utilities. Because a discussion of incentives is not a part of this paper, the reader can refer to other publications, such as a presentation by Richard Sedano and David Littell at the NJ Electric Utility Regulation Workshop on December 3, 2015, entitled *Utility Performance and Redefining the Utility Role.* Retrieved from: http://www.raponline.org/knowledge-center/nj-electric-utility-regulation-workshop-part-4-utility-performance-and-redefining-the-utility-role. Also see Lazar, *Performance-Based Regulation for EU Distribution System Operators;* Sedano, R., & Systems Integration Rhode Island. (2016). Systems Integration Rhode Island (SIRI) Vision Document. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/systems-integration-rhode-island-siri-vision-document; and Sedano, R. (2014). *Experience with Performance Regulation in the US.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/experience-with-performance-regulation-in-the-us

LRAM requires an accurate accounting of the net lost revenues associated with each utility program or measure through an evaluation, measurement, and verification (EM&V) process. This is a labor-intensive exercise that can be contentious and litigious if parties disagree on the accounting of lost revenues or the measurement of energy efficiency program results. Moreover, LRAM can result in customers paying the utility for the net lost revenues associated with decreased sales from the utility energy efficiency programs without netting or taking into account increased sales in other areas (such as growth in electric appliance usage or the addition of electric vehicle charging loads) as the utility retains the incentive to increase sales—which is anathema to the conservation goals embedded in energy efficiency.

High fixed charges do reduce or eliminate the throughput incentive, but only in a manner that does not provide much accountability.[61] Unlike decoupling and LRAM, high fixed charges reduce the customer's incentive to conserve by increasing the payback period on energy efficiency and distributed generation investments.[62] Rates should reflect long-run marginal costs for new generation, transmission, and distribution resources and, thereby, be avoidable; high fixed charges have the effect of pricing incremental purchases of electricity (which require additions of generation, transmission, and distribution facilities) far below the long-run marginal cost.

By sending customers inaccurate price signals and, in the extreme, creating an "all you can consume" rate, it gives customers the false sense that long-run costs for new resources that will be needed to meet future demand will be inconsequential. Based on data on the elasticity of electric demand, the increased consumption will erode over time the savings garnered through energy efficiency programs for which ratepayers have paid. For low-income advocates, there is significant concern around the perverse subsidy that high fixed charges create in which a customer living in a large suburban home pays the same high monthly fixed charge as a low-income customer in a one-bedroom or studio apartment, even though the costs for the utility to serve these customers are dramatically different in that the cost to serve customers in densely populated areas is generally less than in more spread-out residential neighborhoods.[63]

A well-designed decoupling mechanism both removes the utility throughput incentive and allows rates to be set at or very near long-run marginal costs. These are the two key policy objectives that are integral to the successful implementation and sustainability of energy efficiency.

Rating agencies have recognized that decoupling reduces the risk to the utility by providing stable revenues. It enables utilities to project cash flow more accurately and avoid much of the earnings volatility from changes that occur under traditional regulation due to policy goals and other influences such as weather or the economy. It also reduces the need for more frequent rate cases, thereby lowering overall utility costs.[64] When there is less risk to creditors, it can be reflected in the cost of borrowing, by bringing down the overall cost of capital as discussed in Section II.D.3.

From a consumer perspective, decoupling can offer a powerful tool not often available to ratepayers to ensure that the utility is not over-earning. One critical protection is that the decoupling mechanism be symmetric; that is, that just as rates get adjusted upward if actual revenues are less than authorized revenues, rates should be adjusted downward if actual revenues exceed authorized revenues. Currently, this actually occurs a fair amount of the time, as Table 11 demonstrates.[65]

61 Because SFV reduces and perhaps eliminates the throughput incentive, some consider it to be a form of decoupling. It is not. Decoupling is an adjustable price mechanism to achieve a certain level of revenues. Under SFV there is no price adjustment to reflect revenue requirements—just a guarantee of a certain level of revenues based on the number of customers. There are no price adjustments involved.

62 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design

63 See footnote 49.

64 Moody's Investor Services. (2011). *Decoupling and 21st Century Ratemaking: Increased Use of Decoupling Mechanisms is Credit Positive.*

65 Morgan, P., (2013). *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations.* Retrieved from: www.raponline.org

Table 11

Impact on Earnings of Sales Decline for Illustrative SW Electric Utility

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

Typically utilities do not seek adjustments in rates unless they are under-earning. They can go a long time before seeking a rate increase in those cases. Consumer advocates as a whole generally do not have the resources to file complaints seeking a rate decrease, as the burden of proof is usually on them and they have neither the resources nor the data to put together such a case. Decoupling changes that whole paradigm by requiring periodic true-ups to match revenue collections with targeted (i.e., allowed) revenues. Although the utility has the assurance that it will receive its revenue requirement, consumer advocates have the assurance that it will be that and nothing more. Earnings above the revenue requirement amount are not kept by the utility, as has occurred so regularly for so long; instead, over-earnings are returned to the customer.

The impact of net lost revenues on utilities may not be trivial. Nor are the over-earnings associated with utilities exceeding their revenue requirements. Table 11 demonstrates the effect—all else being equal—of small sales variations on an illustrative utility's earnings.

In this example, a change in sales will have a disproportionately large (by a factor of ten) impact on net revenues. Thus, decoupling serves to moderate the utility's ROE so that it is in alignment with what regulators deemed reasonable.

References

Revenue Regulation and Decoupling: A Guide to Theory and Application

www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies

This is an updated version of a guidebook originally published by RAP in 2011, targeted at members of the regulatory community who need to understand both the mechanics of decoupling and the policy issues associated with its use. While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. Appended to this version of the guidebook is a subsequent work, *Decoupling Case Studies: Revenue Regulation Implementation in Six States,* which examines the details of decoupling regimes put in place for utilities in California, Idaho, Maryland, Wisconsin, Massachusetts, and Hawaii.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

http://www.raponline.org/knowledge-center/decoupling-case-studies-revenue-regulation-implementation-in-six-states/

This paper examines revenue regulation, popularly known as decoupling, and the various elements of revenue regulation that can be assembled in numerous ways based on state priorities and preferences to eliminate the throughput incentive. This publication focuses on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid – Massachusetts, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples examine the details of revenue regulation and provide a range of options on how to implement revenue regulation. These specific utilities were chosen in order to represent a range of mechanisms used throughout the US and to contrast differences to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked to assist state regulators and utilities considering implementing revenue regulation.

Charging for Distribution Utility Services: Issues in Rate Design.

http://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

In this report, we evaluate rate structures for electric distribution services, including embedded and marginal cost valuation methods, approaches and principles of rate design, and interactions with competitive markets.

Distribution System Pricing With Distributed Energy Resources

http://www.raponline.org/knowledge-center/distribution-system-pricing-with-distributed-energy-resources/

Technological changes in the electric utility industry bring tremendous opportunities and can also create significant challenges. Rooftop solar photovoltaic (PV) systems and smart appliances and control systems that communicate with the grid can improve system reliability, enable a cleaner and more diverse power system, and create the potential for lower total costs. At the same time, these new resources must be integrated thoughtfully in order to maintain system reliability, provide an equitable sharing of system costs, and avoid unbalanced impacts on different groups of customers, including those who install distributed energy resources (DERs).

Authors Ryan Hledik of Brattle Group and Jim Lazar of Regulatory Assistance Project examine pricing issues related to the business relationship between electric distribution utilities and the owners of DERs. They use specific resources as examples— including grid-integrated water heaters, ice storage air conditioners, PV systems with smart inverters, backup generators, and battery and inverter-based storage systems—to evaluate a variety of different pricing models for their economic efficiency, fairness to all customers, customer satisfaction, ability to generate stable utility revenue, and effect on bill stability. The report also provides recommendations for exploring ideas presented through field pilot testing and rigorous analysis. Carefully designed pilot programs and adequately funded evaluation efforts are needed to ascertain which approaches meet the needs of all participants.

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Appendix B

Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency

American Council for an Energy-Efficient Economy, 2017

Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency

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March 2017

Report U1703

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Brendon Baatz conducts research on energy efficiency policy, utility regulation, energy markets, utility resource planning, electric ratemaking, and utility-sector efficiency programs. Prior to joining ACEEE, Brendon worked for the Federal Energy Regulatory Commission, Maryland Public Service Commission, and Indiana Office of Utility Consumer Counselor. He holds a master of public affairs in policy analysis from Indiana University and a bachelor of science in political science from Arizona State University.

Acknowledgments

This report was made possible through the generous support of the Energy Foundation, Commonwealth Edison, and The JPB Foundation. The author gratefully acknowledges external reviewers, internal reviewers, colleagues, and sponsors who supported this report. External expert reviewers included Douglas Jester from 5 Lakes Energy, Dan Cross-Call from Rocky Mountain Institute, Jim Lazar from Regulatory Assistance Project, Peter Cappers from Lawrence Berkeley National Laboratory, Casimir Bielski and Rick Tempchin from Edison Electric Institute, and John Howat from National Consumer Law Center. External review and support does not imply affiliation or endorsement. Internal reviewers included Neal Elliot, Maggie Molina, Steve Nadel, Jen Amann, Marty Kushler, Reuven Sussman, and Annie Gilleo. Last, I would like to thank Fred Grossberg for developmental editing and managing the editorial process; Keri Schreiner, Sean O'Brien, and Roxanna Usher for copy editing; Eric Schwass for graphics support; and Patrick Kiker, Wendy Koch, and Maxine Chikumbo for their help in launching the report.

Executive Summary

Rapid changes in the electric utility industry are driving utilities to propose new ways of collecting revenues from residential customers. Among these changes are flat or declining electric sales, increased penetration of advanced metering infrastructure, and growing numbers of residential customers with rooftop solar. Many of the industry's proposed changes to residential rate structures are a stark departure from previous billing approaches. Instead of collecting revenues through small customer charges and a flat or inclining volumetric energy rate, many utilities are now proposing higher customer charges, volumetric rates that vary based on the time of day or season, and, in some cases, demand charges.

These proposed changes alter the price signal to customers to conserve electricity and invest in energy efficiency. In this report, we explore the relationship between changes in residential rate design and energy efficiency, focusing on how recently proposed rate structures alter customer behavior through a review of recent pricing studies. We find that some recently proposed rate designs—specifically, higher customer charges and demand charges—could increase overall consumption and discourage investments in energy efficiency technologies.[1] Time-of-use (TOU) rates, potentially combined with other time-varying rate elements such as peak-time rebates (PTR) or critical-peak pricing (CPP), encourage investments in energy efficiency technologies and reduce peak demand. Our review of recent pricing pilots and studies shows that these rates also generally reduce overall consumption, meaning that customers are not using higher levels of electricity from shifting usage outside of peak hours.

ACEEE Principles of Rate Design

There are many competing policy objectives in designing residential rates. The primary function of regulation is to impose on monopoly providers the pricing discipline that markets impose on competitive providers. There are many other subordinate policy objectives, including revenue stability for the utility, affordability for all customers, encouraging conservation, minimizing cross subsidies between rate classes and customers within rate classes, and general clarity and simplicity. Table ES1 summarizes three rate design principles we believe are particularly important.

[1] Demand charges and time-varying rates are not mutually exclusive and can be offered jointly as one rate option. However, as we discuss later in this report, most of the pricing pilots and studies we reviewed do not evaluate these options jointly.

Table ES1. ACEEE principles of rate design

Principle	Definition
Rate simplicity	Rates should be easy for customers to understand and respond to.
Utility revenue stability	Rates should allow utilities the ability to earn commission-authorized revenues to maintain financial health.
Promotion of conservation and energy efficiency	Rates should send price signals to customers to discourage wasteful use of electricity.

Fairness is an additional objective often discussed in the context of rate cases. It has different meanings to different parties. From our perspective, fairness in rate design requires the regulator to balance the interests of the utility and its customers, and also the interests of customer classes and groups within classes. Rates should strive to be cost based and should avoid undue discrimination.

These three principles balance the interests and objectives of customers, utilities, and society at large. Rate simplicity is important because customers need to understand rates to effectively respond to price signals. Utility revenue stability reduces risk in revenue recovery, thereby improving the financial health of electric utilities, which should reduce customer costs through lower cost of debt and equity. Promoting conservation and energy efficiency is critical; discouraging wasteful consumption reduces the need for unnecessary utility infrastructure, such as new power plants, and thereby reduces costs for all customers. This also reduces power plant air emissions associated with energy production, including greenhouse gases.

CUSTOMER RESPONSE AND RATE DESIGN

We reviewed recent pricing pilot studies and other literature to better understand the empirical evidence related to how customers respond to changes in electric prices. Numerous recent pricing pilot studies focus on time-varying rates such as TOU rates, CPP, variable-peak pricing, PTR, and real-time pricing. These studies provide overwhelming evidence that customers respond to changes in volumetric energy rates. Many of the studies document significant peak demand reductions, especially when customers are equipped with technology such as programmable or learning thermostats. Our review of these studies also shows small reductions in overall consumption. Not all estimates were statistically significant at the 90% level, but the results for each treatment group show a consistent trend in reduced overall consumption, with very few showing increased consumption. Table ES2 shows the reduction in overall consumption and peak demand for 50 pricing pilot treatments under various time-varying rates.

Table ES2. Reduction in overall consumption and peak demand for 50 treatment groups in various pricing studies

Rate treatment	Number of observations	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Of the 50 observations, 19 involve annual changes in overall consumption; the remaining 31 are seasonal. Appendix C provides detailed information for each treatment and associated pricing pilot.
CPP = Critical-peak pricing. PTR = Peak-time rebate. TOU = Time-of-use rate.

Many pricing studies are available for time-varying rates, but little evidence exists on how customers respond to three-part rates that include demand charges. A demand charge bills a customer based on maximum demand for any 15- to 60-minute interval period over the course of a month. The charge can be based on maximum demand at any time over the month or assessed during a predefined peak period. Early evidence suggests some reduction in peak demand under three-part rates that include demand charges; however the reduction is less than that of time-varying rates alone. Glasgow, Kentucky, was an early adopter of mandatory demand charges for residential customers but experienced customer dissatisfaction and confusion with the rate, ultimately abandoning the rate as mandatory.[2] Fewer than 20 utilities currently have demand charge rates in place for residential customers, with many targeting customers with large controllable loads, such as central air-conditioning or swimming pools. Most of these rates are voluntary and not much evidence exists on how a mandatory or default residential demand charge rate affects overall consumption and peak demand reductions.

Utility proposals to increase residential customer charges are also very common.[3] As with demand charges, little real-world evidence exists to help us understand how customers respond to higher charges. However, since utilities that increase customer charges must correspondingly reduce the revenues recovered in volumetric energy rates, this approach diminishes the price signal to encourage conservation.

RATE DESIGN'S EFFECT ON ENERGY EFFICIENCY INVESTMENTS

A review of recent literature shows that bill savings are the primary reason customers engage in energy-efficient behaviors and participate in utility-sector energy efficiency

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[2] To learn more about the experience in Glasgow, see bgdailynews.com/news/state-ag-steps-into-glasgow-epb-rate-controversy/article_67b746ee-6af4-11e6-974a-c7c55e838b5e.html.

[3] The customer charge is also known as the service charge, standing charge, connection fee, or fixed charge.

programs. Bill savings result when customers avoid energy charges by reducing consumption through behavior changes or the use of efficient technologies. Various rate design structures alter the energy charges. This affects both the bill savings and the payback period (the number of years it will take a customer to break even on an energy efficiency investment). Longer payback periods make it less likely for a customer to invest in energy efficiency measures.

To understand how changes in rate design alter payback periods, we analyzed energy efficiency data from the Arizona Public Service's *Technical Resource Manual* and load research data from a nearby Arizona utility. Our analysis showed that changes in rate design alter payback periods associated with energy efficiency investments. Figure ES1 shows the payback period differences, in years, for attic insulation under 20 different rate design scenarios. The scenarios tested differences in customer charges, TOU rates, tiered rates, and demand charges.

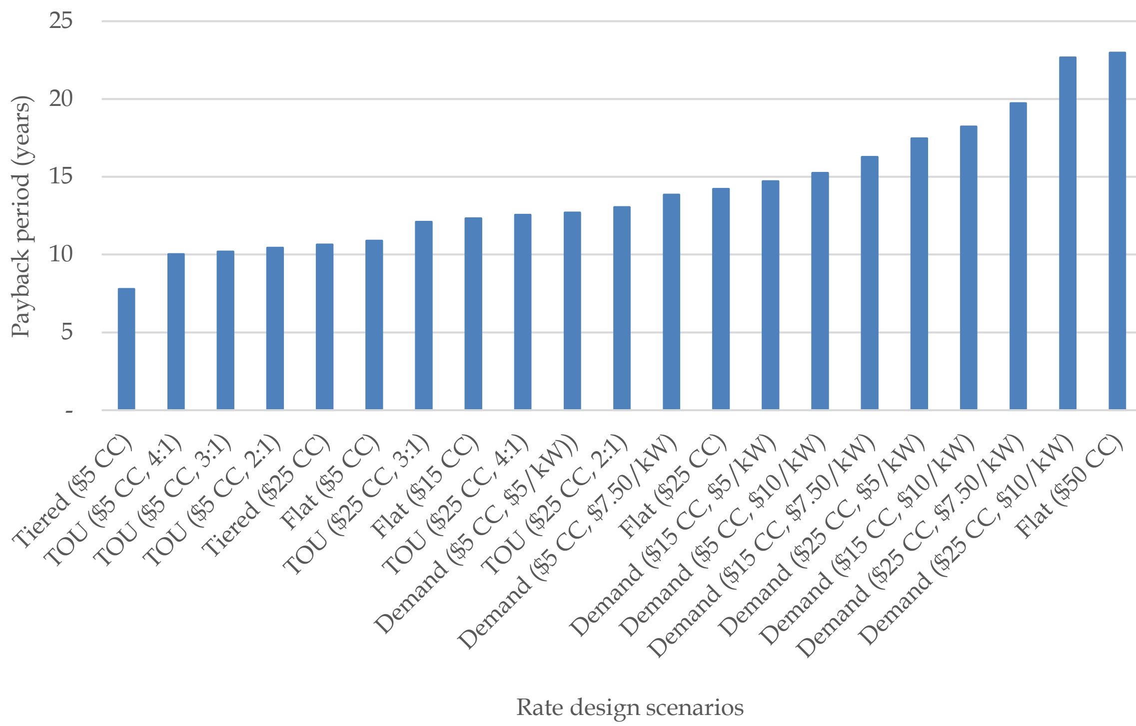

Figure ES1. Payback periods in years under 20 rate design scenarios. CC = Customer charge. TOU = Time-of-use rate. The ratios shown are the on- to off-peak ratios for time-of-use volumetric energy rates.

Scenarios with the longest payback periods are those with higher customer charges (more than $25 per month) and demand charges. The scenarios with the lowest payback periods have lower customer charges, tiered or flat rates, and TOU rates. Moving from a TOU or flat rate with a $5 customer charge to a demand rate with a $25 customer charge and demand charge of $7.50 or $10 per kW nearly doubled the payback period. Moving from an inclining tiered rate with three tiers and a $5 customer charge to a flat rate with a $50 customer charge tripled the payback period.

Rate design scenarios utilizing demand charges show large increases in payback periods for all measures—often more than 30% when compared with flat or TOU rates. Tiered rate scenarios show the shortest payback periods, even when combined with a higher monthly customer charge. Scenarios with higher customer charges often increased payback periods, especially when combined with demand charges.

RATE DESIGN IMPACT ON LOW-INCOME CUSTOMERS

Regulators should consider the impact on low-income customers with any change in rate design. Financially, these customers are often the least able to absorb rate increases and respond to rate changes. Further, because lower-income customers often have a flatter load profile and use less electricity on average than other customers, they may be disproportionately affected by utility proposals—such as a higher customer charges or demand charges—that seek to recover greater levels of costs from low-usage customers. In pricing studies we reviewed, low-income customers were able to respond to changes in volumetric energy prices, but at a lower level than other customers. A flatter load profile also means that, on average, low-income customers might be financially better off than other customers under a TOU rate. Utilities should focus on targeting and recognizing the customers that will be negatively impacted by rate changes to protect vulnerable populations from large rate increases or to assist them with these increases if they occur.

CONCLUSIONS AND RECOMMENDATIONS

Our review of existing studies shows that customers do respond to changes in electric prices. Time-varying rates reduce peak demand and overall consumption. The limited evidence on residential customer response to demand charges shows a smaller reduction in peak demand than with time-varying rates, as well as some difficulty for customers in understanding how the rate is billed. Rate structures recovering more revenue in customer charges must recover less revenue in volumetric rates, reducing the price signal for efficient consumption. Research shows this could lead to increases in overall consumption and higher utility infrastructure costs. All of these changes in rate design also alter payback periods for energy efficiency investments—and some dramatically reduce annual bill savings. Such changes may therefore discourage customers from making energy efficiency investments.

Based on our research on residential rate design, ACEEE finds that confining customer charges to include only customer-specific costs (such as bill and collection) and adopting time-varying rates (specifically, a TOU rate with a CPP or PTR element) comes closest to meeting our three principles of rate design: price signals that encourage conservation and energy efficiency, simplicity, and utility revenue stability. Utilities can reduce costs without sacrificing customer satisfaction by automatically enrolling customers in these rates, while still allowing a return to a standard rate. Utilities should pay special attention to potential financial impacts on low-income customers and ensure that they have the programs, tools, and knowledge necessary to respond to rate changes. Regulators should also support full revenue decoupling for utilities to ensure full recovery of costs, especially for utilities that are risk adverse to new rate designs that could reduce consumption. Finally, regulators should be cautious in adopting demand charges for residential customers; such charges require additional study—possibly in the form of new pilot studies—to understand effects on residential customer usage and peak reduction.

Introduction

Electric utility proposals to modify or alter residential rate design have increased significantly in recent years. Several key factors are driving these proposals, including an increase in customers installing rooftop solar, declining or flattening electric sales, increased penetration of electric vehicles, and proliferation of advanced metering technologies.

In this paper, we explore the relationship between recently proposed changes in residential electric rate design and energy efficiency. We focus primarily on the relationship between rate design and customer response, but we also consider how rate design changes could affect energy efficiency investment decisions. To better understand this relationship, we attempt to answer three questions:

- What effect do various rate structures have on overall consumption of electricity?
- What effect will recently proposed changes in rate design have on payback of various energy efficiency measures?
- What are the implications of various rate design options for low-income customers?

To answer these questions, we first consider rate design goals from various perspectives and outline ACEEE's rate design principles. We then briefly discuss the drivers influencing changes in residential rate design. Following this discussion, we outline recent trends in utility-proposed changes to residential rates. Next, we present a review of pricing pilot studies and literature for several rate design variations, focusing on changes in overall consumption. We then analyze how changes in rate design alter energy efficiency measure payback periods using data from Arizona Public Service. Following this, we review the implications of rate design changes for low-income customers, who are often the least able to respond to utility rate changes. Finally, we offer conclusions from our research, along with recommendations on residential rate design.

Brief Primer on Volumetric Rates

Residential rate design for electric customers has historically relied on a two-part rate: a customer charge and a volumetric price (cents per kilowatt-hour). The customer charge, which is fixed per month regardless of usage, generally includes customer-specific costs for meters, customer service, meter reading, and the line drop from the distribution system into a customer's home. The volumetric rate, which is the price per kilowatt-hour consumed, recovers the remaining distribution network and power supply costs to provide electric service.

The volumetric rate can be billed in several ways. Initially, this rate was often a flat charge. Over time, utilities began charging tiered (or block) rates to offer customers incentives to use more or less electricity. Inclining tiered rates charge a higher rate for increased levels of consumption, sending a price signal to customers to reduce usage. The inclining block rate can be a useful tool for utilities to promote reduced consumption, especially when used as the default rate. According to one study, the implementation of inclining block rates might reduce consumption by 6% in the first few years and potentially more in the long run (Faruqui 2008).

Declining tiered rates offer customers discounts for higher usage levels, promoting increased consumption. These rates are much less common than inclining tiered rates. Declining rates were used historically to stimulate consumption and promote load growth, but have been discouraged more recently through public policy such as the Public Utility Regulatory Policies Act (PURPA) of 1978. Some utilities still offer declining tiered rates in winter months to increase consumption when capacity is underutilized.

Time-of-use (TOU) rates charge a different fee based on the time of day or season. A higher price is charged during on-peak hours, when strain is highest on the electric system and costs are highest for utilities. Off-peak time periods have the lowest charges and occur when demand on the utility system and costs are lowest. Sometimes utilities also use *shoulder periods*, charging customers a lower rate than on-peak, but higher than off-peak. Some TOU rates also vary based on season, with summer rates higher than winter rates for utilities with higher summer demand.

As we describe later in this report, this two-part structure has many rate design variations, including variable-peak pricing (VPP), critical-peak pricing (CPP), TOU rates, and real-time pricing (RTP).[4]

Goals of Rate Design

Residential rate design has several competing policy objectives that regulators must reconcile. These objectives are often argued in specific rate cases, leaving public utility commissions the responsibility of carefully balancing the goals of utilities and the public interest. The most-often cited rate design objectives or goals are those featured in James Bonbright's *Principles of Public Utility Rates* (Bonbright 1961). Bonbright outlined eight criteria for a sound rate structure, but highlights three as primary: a revenue requirement objective (fair return for the utility), a fair cost apportionment objective (rate recovery is evenly distributed among classes and customers), and optimum use or customer rationing objective (rates are designed to discourage wasteful use of public utility services) (Bonbright 1961).

PURPA expanded on Bonbright's eight criteria. The landmark legislation focused on equitable customer rates, efficient use of facilities and resources by utilities, and conservation of energy by end users. Specifically, PURPA required utilities to implement time-of-day rates when cost effective and strongly discouraged the use of declining block (or tiered) rates for energy charges (PURPA 1978).[5] PURPA's overarching objective was to promote conservation and energy efficiency through price signals. The Energy Policy Act of 1992 further articulated these goals, but also expanded the inclusion of energy efficiency in integrated resource planning guidelines and encouraged utilities to consider revenue decoupling and performance incentives for energy efficiency (NRRI 1993).

[4] To learn more about variations of time-varying rates, see Faruqui, Hledik, and Palmer 2012.

[5] Time-of-day rates bill customers a different price for electricity used at different times of the day. Declining tiered rates charge customers less money as they use more electricity.

Bonbright's eight criteria are still widely cited in rate cases today. However much has changed since the initial publication of *Principles of Public Utility Rates* in 1961, most notably the proliferation of distributed generation. Some organizations have therefore argued for an update to the Bonbright principles.

Rocky Mountain Institute (RMI) has advocated for more sophisticated rate design that will account for 21st century technologies and realities. RMI argues that rates should strive for social equity, simplicity of understanding, and resource efficiency (RMI 2015). RMI advocates for moving beyond the simple two-part rate with a flat energy charge, such as TOU, to more sophisticated rate structures that provide clear price signals to guide efficient investment in distributed energy resources (DERs) and utility-scale resources (Glick, Lehrman, and Smith 2014).

In *Smart Rate Design for a Smart Future* (Lazar and Gonzalez 2015), the Regulatory Assistance Project outlines a new vision for rate design based on three principles. First, a customer should be able to connect to the grid for no more than the cost of connecting to the grid. Second, customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume. Third, customers who supply power to the grid should be fairly compensated for the full value of the power they supply (Lazar and Gonzalez 2015).

Electric utilities have also stressed the need for rate design changes to address the increase in DERs. The Edison Electric Institute (EEI), an organization that represents interests of investor-owned electric utilities, states that shifting cost recovery of system assets from those who own onsite generation to those who are unable to participate is unacceptable (EEI 2012). EEI also stresses that customer equity requires that fixed costs be recovered through customer charges. EEI further elaborates on the need for increased customer charges, stating that utilities should "institute a monthly customer service charge to all tariffs in all states in order to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources"(Kind 2013). Utilities often focus on revenue stability and eliminating cross subsidies.[6]

ACEEE PRINCIPLES OF RATE DESIGN

ACEEE has identified three particularly important principles for rate design: simplicity, utility revenue stability, and price signals that encourage conservation and energy efficiency. Here we elaborate on each of these principles and why they are so important.

Promoting conservation and energy efficiency. Rate design should send price signals to customers to discourage wasteful electricity consumption. This objective is consistent with the principles outlined by Bonbright and enacted in PURPA and in the Energy Policy Act. Rates should be cost based and send price signals to customers related to the long-run marginal cost of service, communicating how usage affects future utility system costs. These

[6] Investor-owned utilities also have the objective of minimizing risk and maximizing return to shareholders, which can influence preference for a particular rate design.

signals also allow utilities to communicate to customers when the cost to serve is highest, letting customers reduce demand in these periods.

Rate simplicity. Electricity rates should be easy for customers to understand. Rate simplicity is critical because customers cannot respond to a price signal unless they understand it. Simplicity thus increases customers' ability to respond effectively. These effective responses in turn produce outcomes that are socially optimal, saving all customers money in the long run. Coordinated education efforts can also improve the effectiveness of a rate design.

Utility revenue stability. Rate design should allow utilities the ability to earn commission-authorized revenues. This ability is critical to a utility's financial health. While care should always be taken to ensure that rates are fair and do not facilitate excessive revenues, rate design should not compromise an electric utility's ability to earn authorized revenues. A utility's financial health is important because higher-risk utilities (those in poorer financial health) impose higher costs on customers through higher-cost debt and equity.

Drivers of Change in Residential Rate Design

Several recent developments in the electric utility industry are driving the new proposals in residential rate design. Three of the most important are described below.

FLAT AND DECLINING ELECTRICITY SALES

The first and perhaps most concerning factor for utility management is the fact that electric utility sales are flattening and declining in many regions. According to the US Department of Energy's Energy Information Administration (EIA) (2016), national electric sales have declined in five of the past eight years. Residential sales have remained flat, even as the number of residential customers continues to increase. Figure 1 shows retail electric sales by sector over the past 10 years.

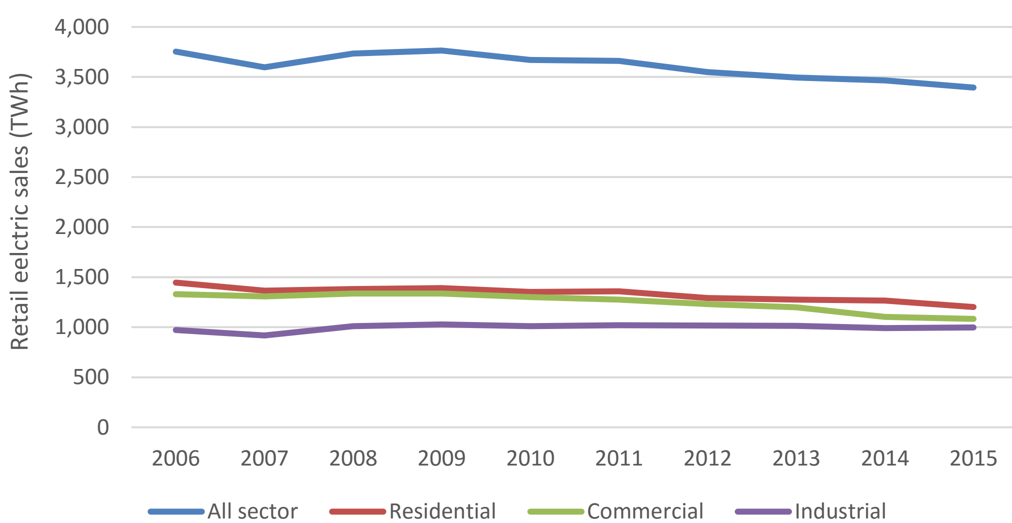

Figure 1. Retail electric sales by sector (in terawatt hours). ***Source:*** **EIA 2016.**

Flattening and declining sales are occurring simultaneously with increases in population and home size. According to the US Census Bureau, the population grew from 298 million in 2006 to 322 million in 2015, an increase of 8% (US Census Bureau 2016a). Further, median single-family home sizes grew from 2,248 square feet in 2006 to 2,467 square feet in 2015, an increase of nearly 10% (US Census Bureau 2016b).

Flattening and declining sales are leading many utilities to reconsider rate design options due to revenue recovery concerns. This is especially true for utilities operating in states that require the use of a historic test year for rate case purposes—that is, a utility must base cost-of-service assumptions and electricity sales on a previous year. If sales are declining, the use of a historic test year can make revenue recovery challenging.

ADVANCED METERING CAPABILITY

A second major factor is the development and adoption of advanced metering infrastructure (AMI) technology. AMI allows utilities access to hourly (or more frequent) customer usage data at relatively low incremental costs. These data allow utilities to utilize time-variant pricing or demand charges for residential customers. Although time-variant pricing existed prior to AMI's spread, the cost of metering until recently prohibited its widespread use.

The number of utility customers with these advanced meters has increased markedly in recent years. In 2007, 2.2 million customers had AMI. By 2016, this number had grown to nearly 58.5 million—a penetration level of approximately 40.6% (FERC 2016). Residential customers have a higher penetration of AMI meters than other customer classes, although not by much.

AMI technology creates an opportunity to use pricing to shape load in desirable ways, and utilities often face regulatory pressure to document the benefits of AMI infrastructure investments. Rate design is important for capturing those benefits. Increased penetration of AMI meters also increases data availability to customers.

GROWTH IN DISTRIBUTED SOLAR PV

The proliferation of residential rooftop solar is also a significant driver of rate design changes. Figure 2 shows the annual installed capacity of rooftop solar installations from 2010 to 2016 for residential and nonresidential customers. Residential rooftop solar capacity grew from almost zero in 2010 to more than 2,500 megawatts in 2016.

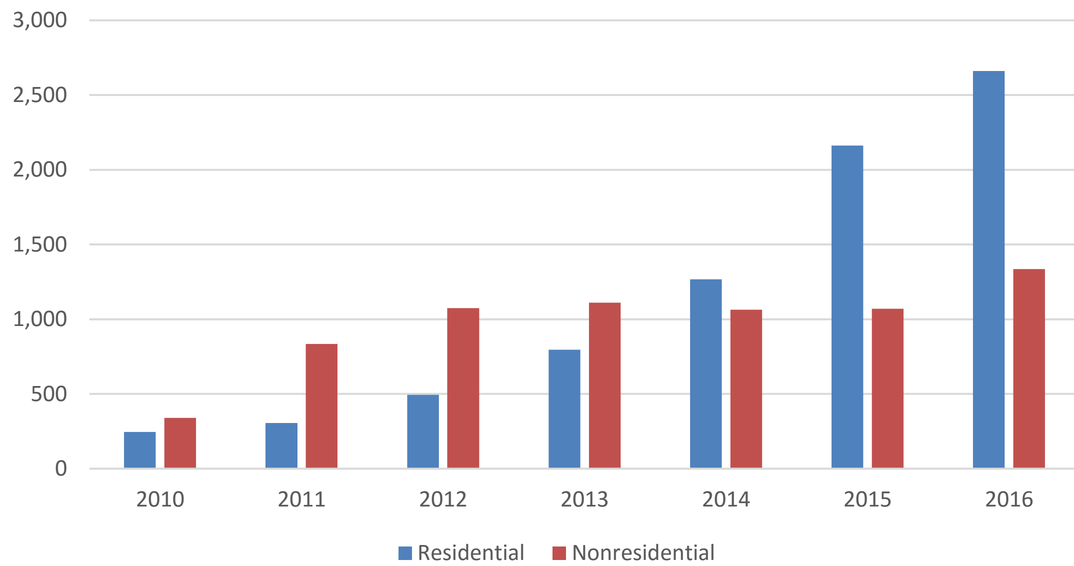

Figure 2. Yearly US solar photovoltaic installations. *Source:* SEIA 2017.

Some utilities argue that the higher numbers of customers with rooftop solar require non-solar customers to subsidize the cost of maintaining the distribution system because the rooftop solar customers avoid significant volumetric charges.[7] In an effort to reduce cross subsidization, some utilities are proposing a number of potential solutions, including higher customer charges and mandatory demand charges. Utilities have also proposed segmenting solar (and other self-generation) customers into rate classes that are separate from other residential customers. The stated intention of these changes is to recover greater costs from rooftop solar customers.

Recent Trends in Residential Rate Design

Here we highlight a few recent trends in residential rate design. These trends are not related to increased revenues for utilities, but are focused on changes to rate structures. New proposals vary by jurisdiction but often include the following changes.

Default TOU rates. Some utilities are moving to default TOU rates instead of the traditional two-part rate structure (a customer charge and flat or inclining energy rate). The California Public Utilities Commission (CPUC), following a three-year examination of rate reform alternatives, ordered the state's investor-owned utilities to begin a transition to default TOU rates for all residential customers starting in 2019 (CPUC 2015). The Massachusetts Department of Public Utilities (DPU), as part of a comprehensive suite of dockets and orders related to grid modernization, ordered the state's electric distribution companies to use a TOU rate with a CPP overlay as the default for basic service customers following the deployment of advanced metering functionality (Massachusetts DPU 2014). The Arizona

[7] Utilities have made this argument in several recent rate cases, including Tucson Electric Power (Docket No. E-01933A-15-0322), UNS Electric Company (Docket No. E-04204A-15-0142), NV Energy (Docket Nos. 15-07041/15-07042), and Madison Gas and Electric (Docket No. 3270-UR-120).

Corporate Commission also required UNS Electric to implement default TOU rates for new customers (ACC 2016).

Introduction of demand charges. Some utilities have also proposed both voluntary and mandatory demand charges for residential customers. Demand charges have a long history of use in billing large commercial and industrial customers, but very little history for residential customers. Only 19 utilities offer demand charges for residential customers, and only two—Arizona Public Service and Black Hills—have subscription rates higher than 1% (Faruqui 2017). Most residential three-part rate options are optional, but in the past year, three small electric cooperative utilities have adopted mandatory demand charge rates for residential customers.[8] Glasgow, Kentucky, instituted mandatory demand charges for residential and small commercial customers in January 2016. The Glasgow electric plant board was forced to reinstate a two-part rate because of strong public dissatisfaction with the mandatory demand charge rate (Tomich 2016).

Recent utility proposals to implement demand charges for residential customers have been met with sweeping opposition. A recent legislative proposal in Illinois included mandatory demand charges for all residential customers in the Ameren Illinois and ComEd service territories. The demand charge proposal was withdrawn from the bill's final version following strong opposition from consumers and Governor Rauner's office (Daniels 2016).

Higher customer charge proposals. Utility proposals to increase customer charges have increased substantially since 2010. Instead of collecting only costs associated with metering, billing, and customer service, utilities are now proposing to collect distribution infrastructure costs in customer charges. As of October 2016, higher customer charge proposal cases were ongoing in 25 states. A review of 87 investor-owned utility rate cases from 2014 through January 2017 show an average proposed increase of 61% (from $9.09 to $14.64), but an average approved increase of only 15%. Appendix A shows the results of these cases in greater detail.

Value of solar and other distributed-generation ratemaking. Several states are now examining the resource value of distributed resources as an alternative to full retail net metering. These states include Arizona, Minnesota, Oregon, Georgia, and New York.[9] Some states have also approved a separate residential self-generation customer class (Nevada). Others have rejected a separate rate class (New Mexico).

Customer Response and Rate Design

Numerous pricing studies in recent decades demonstrate that customers adjust usage in response to changes in electric prices (EPRI 2008). In this section, we review the results of several recent studies testing customer response to various rate designs and discuss other relevant literature. We also outline basic definitions and variations of specific rates. Our

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[8] These utilities include Mid-Carolina Electric Cooperative and Butler Rural Electric Cooperative. Some utilities have also instituted mandatory demand charges for all customers owning distributed generation.

[9] Associated docket numbers are Arizona (Docket No. E-00000J-14-0023), Minnesota (Docket No. 14-65), Oregon (Docket No. UM 1716), Georgia (Docket No. 40161), and New York (Docket Nos. 15-02703/15-E-0751).

review highlights key findings from each pricing study, but we focus on two primary metrics: percentage reduction in peak demand and percentage change in overall consumption.

Considering these two metrics in percentage terms allows comparison across regions with different weather and building characteristics. Other metrics—such as participation approach (opt-in versus default), inclusion of technology (such as a programmable thermostat), and methodology—were secondary in our review, but are also important. Each study utilizes a different methodology to estimate peak reductions and changes in consumption. We do not provide a thorough review of these differences, but that information is available in the primary evaluations.

SCOPE OF REVIEW

We focus our review on studies conducted within the past 15 years. Appendix B offers detailed descriptions of the pricing studies and pilots we reviewed for this report. Although numerous studies were conducted in prior decades, we did not closely review these because they often rely on older technology and research methods. However two earlier studies of note summarized the results of TOU pricing pilots conducted in the 1970s and 1980s.

The first study compiled data from five residential TOU pilots conducted by Carolina Power and Light, Connecticut Light and Power, Los Angeles Department of Water and Power, Southern California Edison, and Wisconsin Public Service. All five of these pilots included some form of mandatory participation. This study concluded that the price differential between peak and off-peak periods is the primary driver in customer response and that TOU rates lead to a reduction in overall usage (Caves, Christensen, and Herriges 1984). The second study reviewed the results of 12 pricing pilots from the late 1970s. It concluded that TOU pricing generally reduces peak demand and daily energy consumption. Higher-use customers also were more responsive to TOU rates than low-use customers (Faruqui and Malko 1983).

We discuss different pricing designs separately in this report, but in reality these approaches are not mutually exclusive and can be offered jointly. For example, one utility might offer a pricing option that includes a high customer charge, flat energy rate, and time-based demand charge, while another offers a rate with a low customer charge, TOU energy rate, and a demand charge assessed during any hour of the month (that is, one not limited to a peak period).

TIME-VARYING RATES

Within time-varying rates, we include TOU rates, CPP, VPP, and peak-time rebates (PTR). CPP, PTR, and VPP are also referred to as *dynamic* because the rates are adjusted in real time based on system conditions. RTP is also a time-varying rate, but we review it in its own section below. The common characteristics of these rate structures are that prices vary by the season or time of day. Within these different rate types, however, several differences exist. Here we define each rate type and then discuss findings from pricing pilots and other relevant literature.

Time-of-use rates. TOU rates vary on a fixed schedule to recover higher revenue during times when utility demands (and costs) are higher and lower revenue at other times. The intention of a TOU rate is to send customers price signals to reduce usage during peak hours at times when utility costs are highest. TOU rates also send price signals to customers related to future investments: if a utility can reduce peak demand, costly investments in new infrastructure may be avoided or deferred.[10] TOU rates have existed for several decades but are increasingly popular where AMI technology penetration is high. Most TOU rates are opt in or voluntary. Recent industry experience shows that pursuing a voluntary approach to TOU rates typically means that less than 2% of residential customers participate, although enrollment for some utilities is much higher because of proactive marketing and education (FERC 2012). Table 1 shows an illustrative TOU rate structure with seasonal differences.

Table 1. TOU rate structure with seasonal differences

Season	Period	Hours	Price per kWh
Summer	On-peak	4–7 pm weekdays	$0.21
Summer	Off-peak	All other weekday hours; all weekend hours	$0.09
Winter	On-peak	6–9 am and 6–9 pm weekdays	$0.15
Winter	Off-peak	All other weekday hours; all weekend hours	$0.07

Critical-peak pricing. Under CPP, a higher energy rate is assessed during an announced event for a limited number of hours. The higher energy rate is the result of higher wholesale electricity prices and allocation of costs for capacity needed at peak load, and can exceed $1 per kWh (Faruqui and Sergici 2013). The announced events are often limited to a certain number of days or hours per year. Like many other rate design options, the increased prevalence of CPP programs is largely driven by AMI technology. Table 2 shows an illustrative CPP rate structure combined with a TOU element.

Table 2. CPP rate structure combined with TOU

Period	Hours	Price/kWh
On-peak	4–7 pm weekdays	$0.15
Off-peak	All other weekday hours; all weekends	$0.07
Critical-peak event	3–7 pm during event day	$0.75

[10] The utility infrastructure referenced here would include transmission, distribution, and generation assets.

Peak-time rebate. The PTR rate structure awards customers with a financial rebate for energy saved during announced peak events. Generally, a utility will notify customers in advance of the opportunity to reduce usage for a bill credit of a specified amount. PTR is a low-risk option for customers because they have nothing to lose financially. However CPP often reduces rates at non-event times, while PTR increases rates at non-event times to offset the revenue effects of the events. Some utilities, such as PEPCO Maryland, automatically enroll customers in PTR.

Variable-peak pricing. VPP is a pricing structure that charges customers a higher rate for a predefined peak period. The rate's on-peak price component can change day by day, and customers are often alerted about it by a specific time during the previous day. Table 3 shows an example of a VPP rate structure: the off-peak period is constant at seven cents per kWh but in the event of high or critical demand, a utility would alert customers of a higher price during a predetermined peak period, such as 3–7 pm.

Table 3. VPP rate structure

Price/kWh	Description
$0.07	Off-peak/low
$0.12	Standard
$0.25	High
$0.50	Critical

Peak Demand Reductions

A primary benefit of time-varying rates is a reduction in peak demand and associated generation, transmission, and distribution costs. A 2012 survey of 24 pilots conducted between 1997 and 2011 demonstrated significant peak-load reductions from time-varying rates (Faruqui, Hledik, and Palmer 2012). The most significant peak demand reductions came from CPP, especially those treatments using enabling technology such as a programmable thermostat. Figure 3 shows the average peak reductions from 109 rate treatments—that is, combinations of time-varying rates and enabling technologies—in the 24 pilots.

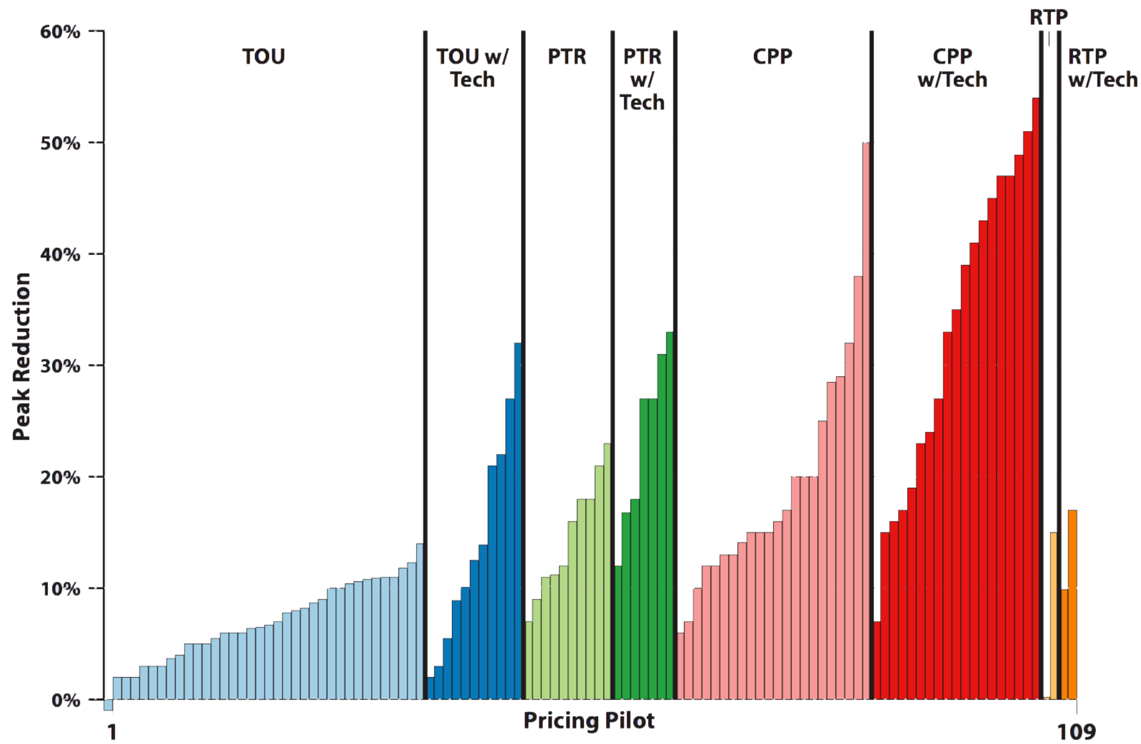

Figure 3. Average peak reduction from time-varying rate pilots. *Source:* Faruqui, Hledik, and Palmer 2012.

The 2012 study found that the on- to off-peak ratio of prices is a key driver in price response. Rate treatments with higher on- to off-peak ratios tended to produce larger peak demand reductions. A 2016 update to these findings expanded on the importance of the on- to off-peak ratio in increasing peak demand reductions, finding an "arc of price responsiveness," meaning that customer response increased, but then diminished at higher on- to off-peak ratios (Faruqui et al. 2016). Figure 4 shows the results from the updated study. The figure shows 204 pricing treatments, with price-only and price-plus technological intervention shown separately. The figure demonstrates a relationship between higher peak demand reduction and an increase in on- to off-peak ratio, especially in cases with technological intervention.

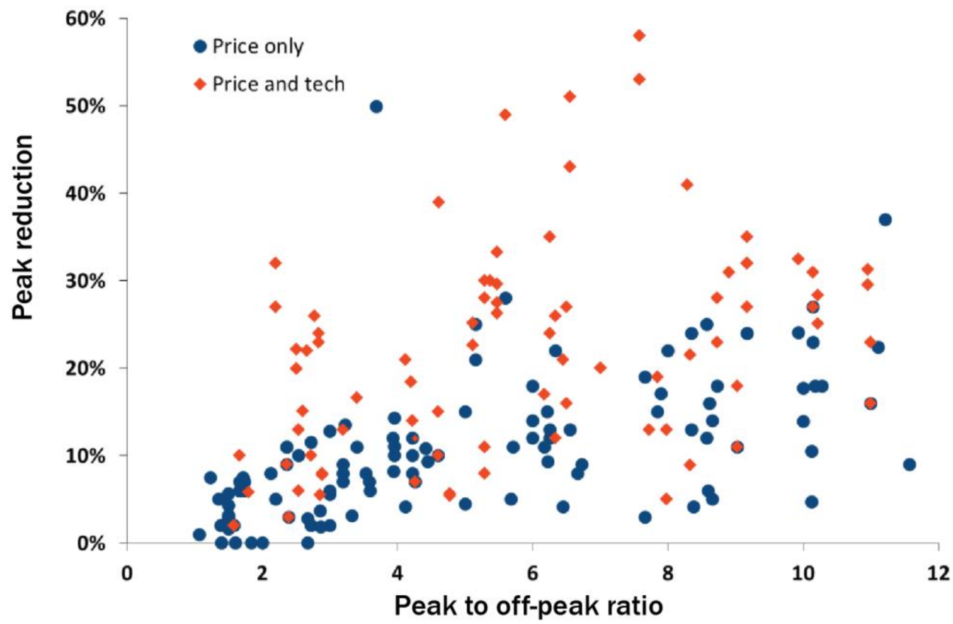

Figure 4. Peak period impacts for 204 time-varying rate treatments. Of the 204 treatments, 26 have ratios greater than 12:1. *Source:* Faruqui et al. 2016.

Change in Overall Consumption

The majority of the studies we reviewed clearly demonstrate peak demand reductions, which are a significant benefit. However time-varying rates may shift consumption from on- to off-peak periods. The magnitude of this shift varies based on several factors, including whether or not customers can actually shift usage from one hour to another. A lower price in an off-peak period also could potentially increase consumption in these periods. Our goal was to understand how time-varying rates affect overall consumption.

Six of the eight pricing pilots we reviewed for CPP, TOU, and PTR included estimates of total consumption changes due to pricing or technology treatments (for more details, see appendices B and C). We collected 50 observations within those six studies. An *observation* is a variation in technology or treatment in a specific year. For all 50 observations, the average peak demand reduction was 16% and the average reduction in consumption was 2.1%. Of the 50 observations, 19 were from year-long experiments, three were from fall/winter periods, and the remaining 28 were from summer experiments. Technology was involved in 16 of our 50 observations. The average peak demand reduction for those with technology was 23%, and the average reduction in overall consumption was 1.35%, relative to the control group. Table 4 shows descriptive statistics for each rate treatment group.

Table 4. Reduction in overall consumption and peak demand for 50 treatment groups in various pricing studies

Rate treatment	Number of observations	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Of the 50 observations, 19 involve annual changes in overall consumption; the remaining 31 are seasonal. Appendix C provides detailed information for each treatment and associated pricing pilot.

When reviewing the reductions in table 4 and figure 5, keep in mind that not all observations were statistically significant. However 46 of 50 observations showed a reduction in overall consumption. Only four observations showed an increase in consumption, with an average of 1%. All four of these observations involved a CPP rate.

Figure 5 shows the relationship between peak demand and overall consumption changes. This plot of all 50 observations indicates a very weak relationship between the two variables.

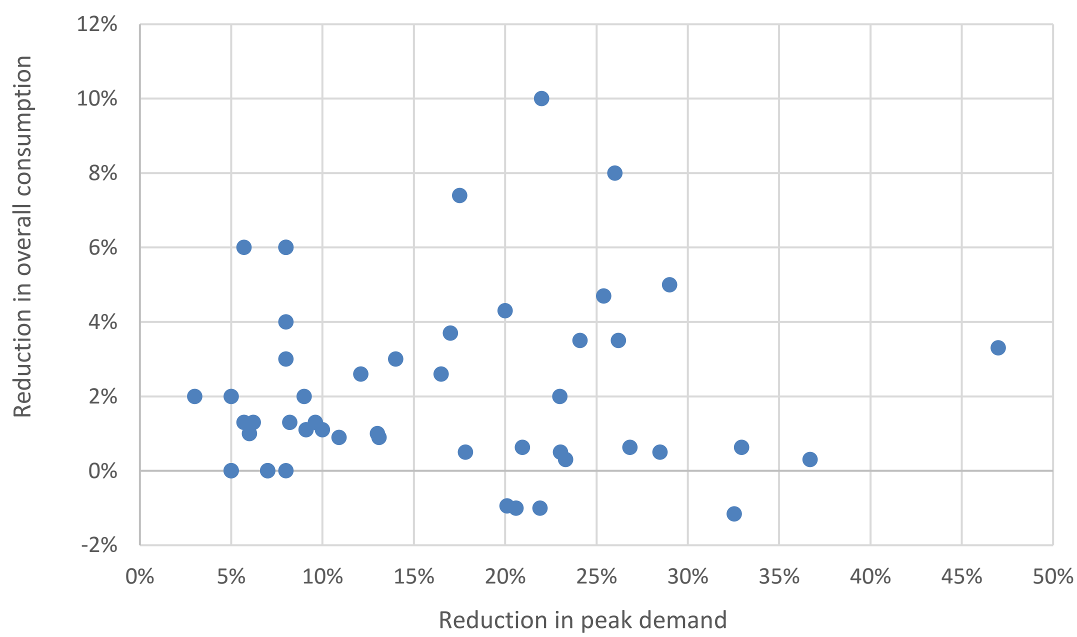

Figure 5. Reductions in peak demand and overall consumption for 50 observations in pricing pilots

Green Mountain Power Pricing Pilot and the Oklahoma Gas and Electric Consumer Behavior Study were not included in figure 5 because neither study explicitly included changes in overall consumption. However both demonstrated significant reductions in peak demand for nearly all treatments. The evaluation of the Oklahoma pilot included changes in off-peak consumption. For many treatment groups, the off-peak consumption increased, but did not offset the reductions in on-peak usage. The Green Mountain Power Pricing Pilot measured only the differences in overall usage for those with in-home display (IHD) devices and those without. Evaluation of the Green Mountain Power pilot showed the use of IHD technology reduced monthly consumption at a statistically significant level of between 2% and 5.3%.

Cost Basis for Time-Varying Rates

The time-varying rates outlined in this section are structurally different and align to system costs in different ways. CPP, VPP, and PTR are designed to send price signals about specific system conditions to customers in near real time. TOU rates are set based on projected system peaks and do not always capture real-time changes in hour-to-hour prices. However TOU rates can be combined with PTR or CPP. Time-varying rates are more closely aligned with utility system costs than flat rates. When compared with noncoincident peak demand charges, TOU rates may be better at reflecting the cost structure for most demand-related costs (NARUC 2016).

Conclusions for Time-Varying Rates

Our review shows that time-varying rate structures such as CPP, TOU, or PTR generally reduce overall consumption. In fact, the observations we collected document reductions in overall consumption for all rate types. Although many of the observations were not statistically significant, we can also infer that increases in overall consumption are not a normal occurrence in the pricing studies we reviewed.

REAL-TIME PRICING

RTP provides customers hourly electricity prices in real time based on wholesale market prices. The real-time price reflects the actual short-run marginal cost to provide service during peak periods of the day. Therefore the customer has a price signal to reduce usage at times when it is most valuable. Real-time prices reflect current conditions and provide a price signal based on the current marginal cost of power at a specific location (Hogan 2014). Real-time prices, as implemented for residential customers thus far, focus on energy prices and do not capture costs associated with generation, transmission, or distribution capacity.

Pricing information can be sent to customers in various ways, including email, text, telephone, or an installed in-home device. However some consumer advocates have argued RTP exposes customers to a high level of risk because of wholesale electricity markets' inherent volatility. While some states have experience offering RTP to industrial and commercial customers, very few utilities in the United States offer RTP to residential customers.

Commonwealth Edison in Illinois offers one of the largest residential RTP programs. At 4:30 pm, customers are sent day-ahead energy prices for the next day, but are billed based on the actual real-time prices. Figure 6 shows the day-ahead and real-time prices for a 24-hour period during a summer weekday in 2015.

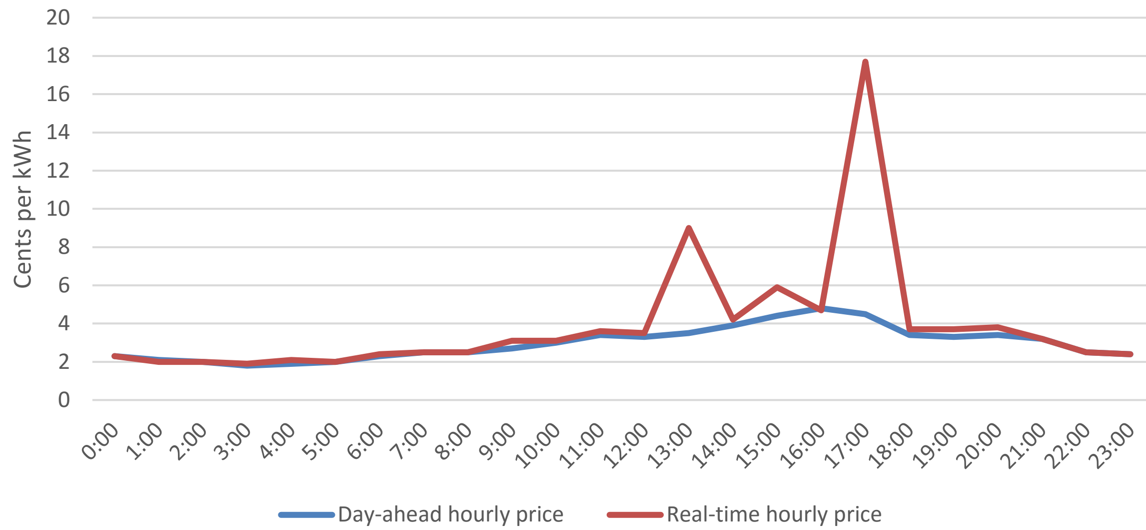

Figure 2. Day-ahead and real-time prices for ComEd hourly pricing customers on August 12, 2015. *Source:* ComEd 2016.

In total, we reviewed four RTP programs. Two of these programs are ongoing (Ameren Illinois and Commonwealth Edison) and two are completed pilot studies (PEPCO PowerCents DC and Community Energy Cooperative Energy-Smart Pricing Plan). A review of these programs shows that customers do respond to higher prices and reduce overall consumption. An evaluation of the Commonwealth Edson residential RTP program showed an annual reduction in overall consumption of 4% from 2007 through 2010. However all four of these programs included only customers choosing to participate, thereby introducing selection bias into these findings.

DEMAND CHARGES

Some utilities are now offering a three-part residential rate consisting of a customer charge, volumetric rate (which can be time based), and a demand charge. The demand charge collects revenue based on a customer's peak demand during a defined time period. Demand charges have a long history of use for commercial and industrial customers, but very little history with residential customers. Table 5 shows select utilities with residential demand charges; this list is not exhaustive.

Table 5. Residential three-part rates for select utilities

Utility	State	Name	Customer charge ($/month)	Demand charge ($/kW)	Demand charge billing period	Volumetric rate
Alabama Power	AL	Time Advantage-Demand	$14.50	$1.50	All hours, all days	Varies, TOU
Arizona Public Service	AZ	Combined Advantage	$16.68	$13.50 (summer) $9.30 (winter)	Weekdays, 12–7 pm	Varies, TOU
UNS Electric	AZ	Residential Service Demand	$15.00	$5.10 (up to 7 kW) $7.10 (more than 7 kW)	Weekdays, 3–7 pm (summer); 6–9 am and 6–9 pm (winter)	6.61¢/kWh
Black Hills Energy	SD	Demand Service	$13.00	$8.10	All hours, all days	2.26¢/kWh
Black Hills Energy	WY	Demand Service	$15.50	$8.25	All hours, all days	6.43¢/kWh
Xcel Energy	CO	Demand Service	$12.25	$8.57 (summer) $6.59 (winter)	All hours, all days	1.74¢/kWh
Intermountain Rural Electric Association	CO	Residential Demand Metered	$10.00	$14/kW	All hours, all days	6.59¢/kWh
Glasgow Electric Board	KY	Residential Rate RS	$29.16	$11.33 (summer) $10.37 (winter)	Weekdays excluding holidays, 1–7 pm (summer); 6–10 am (winter)	Varies, TOU

The design of a residential three-part rate with demand charges can vary significantly. While these rates include a customer charge and a volumetric rate, the structure of the demand charge varies. The most significant differences are the time period in which the demand charge is assessed (peak or all hours) and the length of time peak demand is measured (often 60 minutes, but can be 15 or 30 minutes). Demand charges are intended to collect demand- or capacity-related costs of distribution, generation, and/or transmission.[11]

Cost Basis for Demand Charges

The differences in how a demand charge might be designed raises questions about the cost causation of such a charge. For example, if a demand charge is billed based on noncoincident peak (the customer's individual highest demand for a month, regardless of when it occurs relative to the utility system peak), the charge may not align with costs driving system peak. Also, if the demand charge is based on noncoincident peak, it may not recognize the diversity of usage from residential customers. Distribution system

[11] For a more detailed explanation on how demand charges can be designed to recover different categories of cost, see RMI 2015 and Chernick et al. 2016.

transformers and other localized distribution infrastructure are designed to meet combined and diverse loads (Chernick et al. 2016). A noncoincident peak demand charge may over-recover costs associated with that specific investment because customers sharing the capacity likely have individual peak demands at different times of the day; as a result, the sum of their noncoincident demands might exceed actual total capacity.

A cost-based coincident peak demand charge is difficult to design. Utility system peaks vary by year, often based on weather. Therefore utilities do not know when the monthly system peak is until month's end. Utilities could design a coincident peak demand charge based on expected hours during the day, but then risk a rate design that does not actually align with costs when the system peak falls outside of predetermined time periods. Many demand charges are also based on a 15-, 30-, or 60-minute time period in a single month. This single hour (or less) is not the only driver—and might not be even the primary driver—of a customer's contribution to costs associated with generation, transmission, and distribution capacity (Bornstein 2016).

The National Association of Regulatory Utility Commissioners (NARUC) *1949 Cost Allocation Handbook* identified several criteria for evaluating the equity of capacity cost recovery in rates; these were expressed succinctly in *Public Utility Economics* (Garfield and Lovejoy 1964). Table 6 compares the three types of rate design and how each achieves the criteria summarized by Garfield and Lovejoy (Lazar 2016). The table shows that the TOU energy charge is superior to coincident peak and noncoincident peak demand charges in terms of capacity cost recovery.

Table 6. Garfield and Lovejoy criteria for capacity cost recovery

Garfield and Lovejoy criteria	Coincident peak demand charge	Noncoincident peak demand charge	TOU energy charge
All customers should contribute to the recovery of capacity costs	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant costs	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something	Y	N	Y

Evidence of Demand Charge Impacts on Customer Behavior

Little evidence exists on how demand charges impact annual consumption or peak demand reduction, and few pilot studies focus on residential demand charges. A review of three pilots—two from the late 1970s and one from Norway in 2009—provide evidence of demand reductions, but the reductions varied widely within the studies (Hledik 2014). Further, because the two US studies are very old, they do not include the potential impact of modern technology.

The Brattle Group developed a model to simulate customer response to a three-part rate using an extensive library of customer price elasticity estimates found in previous pricing pilots. The model includes results for both load shifting and conservation effects (Hledik 2015). It predicts reductions in demand for the individual customer, the class peak, and the system peak, but also shows an increase in annual consumption. Table 7 shows the results of this analysis.

Table 7. Simulated average change in residential load metrics due to price response to a three-part rate

Metric	Average change
Customer max demand	–5.3%
Class peak demand	–1.7%
System peak-coincident demand	–1.5%
Annual consumption	0.2%

Source: Hledik 2015

Arizona Public Service (APS) also recently published a review of customer price response to demand charges (Snook and Grabel 2016). APS has more than 117,000 customers subscribed to its TOU demand rate. The study reviews usage changes for 977 customers who opted to move from the traditional energy TOU to the demand TOU rate. It demonstrates that these customers reduced summer peak demand by 0.3 kW or 3.9% on average and that residential customers reduced summer consumption by 2.9%, likely because of higher summer energy prices. However the annual consumption impacts are unclear because the study does not include changes in winter consumption. It is also unclear what information or technology customers received on reducing consumption and how much influence education or technology had on the reductions. The demographic characteristics of the treatment group are unknown; further, the customers opted into this rate, increasing the potential for selection bias in the study. Finally, it is unclear if the customers are responding to the demand charge or the TOU energy rate. Therefore it is difficult to draw definitive conclusions from this study.

The introduction of demand charges for solar customers has negatively affected rooftop solar installations as well. Salt River Project in Arizona was among the first electric utilities to implement a mandatory demand charge for rooftop solar customers. Following the rate design's approval in 2015, applications for rooftop solar permits dropped more than 95% (Magill 2015). A study one year after the rate's implementation showed that only 14% of rooftop solar customers were saving money on electric bills (Randazzo 2016). The Intermountain Rural Electric Association also experienced a similar decline in rooftop solar installations following the introduction of demand charges for its customers (Jaffe 2015).

Conclusions for Demand Charges

Current utility experience with residential demand charges demonstrates a lack of data and information on how customers respond to these rates. In the studies we reviewed, demand charges demonstrated smaller reductions in peak demand compared to other rate options, including TOU, CPP, and PTR. The APS study and the Brattle simulated price response produced contradictory results in terms of changes in annual consumption. The Glasgow, Kentucky, experience—which was an early instance of mandatory demand charges for the entire residential customer class—indicated that some customers faced much higher bills and may have had difficulty responding to the new rate structure. Given the results of the studies we reviewed, more research is needed to fully understand customer response and understanding, as well as the impact on low-income customers. Research should also evaluate the effect of the demand charge relative to any energy rate included in the rate design.

HIGHER CUSTOMER CHARGES

In recent years, we have seen a considerable increase in the number of utility proposals to raise the monthly customer charge (also known as the service charge, standing charge, connection fee, or fixed charge). Historically, this charge was designed primarily to collect the customer-specific costs of metering, customer service, billing, and the service drop. Utilities are now proposing to recover more distribution infrastructure costs in this charge.

Assuming revenue neutral rates, increasing the customer charge decreases the volumetric energy rates. Lower volumetric rates reduce the price signal to customers to conserve electricity and engage in energy efficiency. Consider an example based on load research data in the most recent UNS Electric rate case. In this example, we assume a proposed increase in the customer charge of $10 per month (raising it from $10 to $20). As table 8 shows, the proposed increase in the customer charge reduces the revenue collected in the energy rate by 11%, reducing the energy rate in $/kWh by 14%.

Table 8. Changes in volumetric rate based on changes in customer charge

Customer charge ($/month)	Revenue requirement collected in customer charge	Revenue requirement remaining	% of revenue requirement collected in customer charge	Energy rate ($/kWh)
$0	$0	$2,508,500	0%	$0.1139
$5	$138,540	$2,369,960	6%	$0.1076
$10	$277,080	$2,231,420	11%	$0.1013
$15	$415,620	$2,092,880	17%	$0.0950
$20	$554,160	$1,954,340	22%	$0.0887
$25	$692,700	$1,815,800	28%	$0.0824
$30	$831,240	$1,677,260	33%	$0.0761
$35	$969,780	$1,538,720	39%	$0.0699
$40	$1,108,320	$1,400,180	44%	$0.0636
$45	$1,246,860	$1,261,640	50%	$0.0573
$50	$1,385,400	$1,123,100	55%	$0.0510

Values based on load research sample in UNS Electric 2015 rate case

As this example demonstrates, as a utility moves more revenue collection to customer charges, the volumetric rate must correspondingly decrease. In this case, transferring 11% of the revenue requirement from the volumetric energy rate to the customer charge means a reduction in the energy rate of approximately 1.5 cents per kWh.

According to a 2008 study on electric price elasticity, the Electric Power Research Institute (EPRI) found that customers do respond to changes in electric prices (EPRI 2008). Price elasticity is a measure of customer response to changes in prices. The study found that customer response varies based on the time period considered. Customers tend to respond to changes in electric prices at greater levels in the long term (greater than five years) than the short term (between one and five years). Table 9 shows the study's results.

Table 9. EPRI price elasticity estimates

Sector	Short run			Long run		
	Mean	Low	High	Mean	Low	High
Residential	−0.3	−0.2	−0.6	−0.9	−0.7	−1.4
Commercial	−0.3	−0.2	−0.7	−1.1	−0.8	−1.3
Industrial	−0.2	−0.1	−0.3	−1.2	−0.9	−1.4

Source: EPRI 2008

Using the example in table 8 and the elasticities in table 9, we can forecast changes in overall consumption. Assuming the residential sector price elasticity estimates, overall consumption will increase from between 2.8% and 8.5% in the short run, and 9.9% and 19.8% in the long run. Even a conservative estimate using the low short- and long-run elasticity estimates projects increased consumption in our example. Figure 7 shows the results of this analysis.

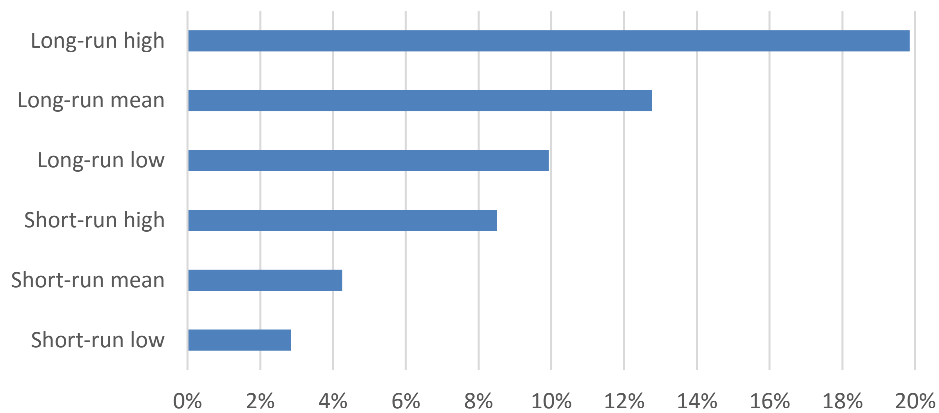

Figure 7. Overall change in consumption when moving from a $10 to a $20 customer charge under EPRI 2008 residential price elasticity estimates

We could not locate any existing pilot studies in which a utility implemented higher customer charges and corresponding lower volumetric rates. While such a study may not exist, research into customer response tells us that consumers will increase consumption of electricity when facing lower rates. Our example demonstrates the potential implications for overall consumption in rate designs with higher customer charges. Increased customer consumption will require additional utility infrastructure in the long term, as utilities will need to meet growing demand. High customer charges are undesirable as they will increase long-term costs for all utility customers.

Conclusions for Customer Charges

When they exceed basic customer costs such as metering, customer service, billing, and the service line drop, higher customer charges are not cost based. Further, high customer charges discourage energy efficiency investments by reducing the volumetric rate price signal. Some research also suggests that higher customer charges—when combined with lower volumetric rates—may increase overall consumption, which would lead to higher utility system costs.

Rate Design and Energy Efficiency Investments

Residential customers reduce electricity usage for a variety of reasons, including to save money on electric or gas bills, increase comfort, reduce environmental impacts, and improve aesthetics. Customers also engage in energy efficiency programs when replacing broken or failing equipment. While nonmonetary benefits are important, recent research indicates customers primarily reduce usage and participate in energy efficiency programs to reduce bills and save money.

For example, a 2010 Accenture survey found that 88% of respondents cited decreases in the amount of an electric bill as a factor that most encouraged the use of electricity management programs (Accenture 2010). Another study conducted in 2014 surveyed residential customers who had previously installed solar systems. When this survey asked customers about factors that motivated their energy efficiency upgrades, 71.8% ranked lower energy bills as most important (Langheim, Arreola, and Reese 2014).

Further, a 2013 focus group study also found that the overwhelming response to why people make energy improvements is to save money and energy. This result was consistent in all six geographic focus group locations; other reasons cited included comfort, reduced noise, improved value, environmental and sustainability concerns, appearance, and health and safety (DOE 2013b).

Another study surveyed 615 people in Vermont not known to have previously participated in statewide home performance or home retrofit programs. The study sought to discover the barriers to participation in these programs. When asked about reasons for completing home energy projects over the past five years, 62% cited lowering electric or heating bills as a reason. This compares to only 18% for improving comfort, 16% for reducing carbon impacts or helping the environment, and 11% for replacing broken or failing equipment (GDS 2013a).

A national survey conducted by the Acadia Consulting Group produced a similar response. In this study, the 1,278 respondents included contractors, energy auditors, weatherization agencies, and other trade groups. The survey's primary objective was to collect information related to challenges facing the home performance industry and how outside organizations can support this industry in the future. When asked what motivates homeowners to make energy efficiency or clean energy improvements in homes, 84% cited saving money and 68% said improving comfort (Acadia 2017).

As these studies clearly show, reducing bills and saving money is the primary driver for customers to engage in energy efficiency. Rate design can alter the payback periods of energy efficiency investments. A payback period analysis determines how many years it will take a customer to break even on their investment. Bill savings repay the customer. The higher the electricity rate avoided, the quicker the payback will occur.

METHODOLOGY

To better understand rate design's effect on payback periods, we reviewed payback periods for 14 energy efficiency measures or programs under 20 rate design scenarios. To conduct this analysis, we used energy efficiency savings and incremental cost data from the Arizona Public Service's *Technical Resource Manual* (APS TRM). This resource is updated annually and approved by the Arizona Corporate Commission. Table 10 shows the 14 programs, including data on annual energy savings, coincident peak demand reduction, and incremental cost (the cost of a measure or program above the baseline investment). Appendix D provides detailed descriptions of each program and measure.

Table 10. Measures and programs used in the analysis

Measure or program	Annual energy savings (kWh)	Coincident peak demand savings (kW)	Incremental cost ($)
LED 40-watt replacement	27.17	0.00139	$4.04
LED 60-watt replacement	36.87	0.00189	$6.02
LED 75-watt replacement	42.69	0.00219	$9.91
Variable-speed pool pump	1,725	0.19600	$437
Duct test and repair	865	0.81282	$907
Prescriptive duct repair	421	0.39572	$300
Advanced diagnostic tune-up	492	0.27232	$157
Equipment replacement with quality installation	576	0.62160	$330
New construction ESTAR Homes v. 3.0	2,156	0.86000	$2,132
New construction ESTAR Homes v. 3.0—Tier 2	3,247	1.31000	$2,830
New construction total program	2,593	1.04000	$2,411
Attic insulation	787	0.28000	$922
Air sealing and attic insulation	1,235	0.36000	$1,610
Smart strip	96	0.02532	$22.49

We calculated payback periods for these measures using the hourly load shape data in table 11 for 20 iterations of rate design. All 20 iterations are *revenue neutral*, that is, they produce the same revenue outcomes for the utility. The first three scenarios are simple two-part rates with different levels of customer charge and corresponding flat volumetric charges. The second set of scenarios involves a tiered rate structure under two different potential customer charges: $5 and $25. The next six scenarios are iterations of TOU rates based on different combinations of customer charges ($5 and $25) and corresponding volumetric rates based on different on- to off-peak ratios. The final nine scenarios are iterations of three-part rates consisting of customer, demand, and volumetric charges at various levels. Appendix E shows the specific rates for each scenario.

We relied on hourly load profile data from the Open Energy Information (Open EI) database.[12] Our analysis focuses on residential measures only, although the APS TRM and Open EI database contain relevant data on commercial and industrial measures as well. The hourly load data is for the Phoenix region. We normalized these data and created bins based on a four-hour peak time period from 3–8 pm on weekdays.[13] To do this, we summed the

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[12] This dataset contains hourly load profile data for residential buildings based on the Building America House Simulation Protocols (Hendron and Engebrecht 2010). This dataset also uses the Residential Energy Consumption Survey (RECS) for statistical references of building types by location (Open EI 2016).

[13] We did not remove holidays for this analysis.

load in each hour and then divided each bin by the number of hours in each bin. Table 11 shows the load shape bins used for this analysis.

Table 11. Load shapes used for payback analysis (percentage of hours in each time period)

Load shape	Summer off-peak	Summer on-peak	Winter off-peak	Winter on-peak
Whole facility	52%	13%	28%	6%
HVAC	72%	23%	3%	1%
Interior lights	36%	5%	49%	10%
Interior equipment	41%	9%	41%	9%

LIMITATIONS OF ANALYSIS

This analysis has several limitations. First, it is limited to one utility service territory. Each utility service territory is different in terms of weather, geographic scope, and demographics. Weather differences will alter payback periods for different measures. Second, the analysis focuses on a five-hour peak window. Using a longer or shorter peak period will alter the payback periods. Finally, this analysis did not assume any customer response (changes in usage patterns and consumption) to the changes in rate design, which would likely occur for most customers.

FLAT AND TIERED RATE RESULTS

The first five scenarios are based on iterations of flat rates. Table 12 shows the assumptions for each scenario. The tiered rates were constructed using three tiers. We assumed energy savings from each measure occurred in the highest tier, shown as the energy rate in table 12. All rate scenarios are revenue-neutral based on the same test year sales levels.

Table 12. Assumptions for flat-rate scenarios

Scenario	Customer charge ($/month)	Energy rate type	Effective energy rate ($/kWh)
1	$5	3 tiers	0.1504
2	$25	3 tiers	0.1101
3	$5	Flat	0.1076
4	$25	Flat	0.0824
5	$50	Flat	0.0510

Table 13 shows the assumptions for the two scenarios with tiered rates.

Table 13. Tiered rate structure price assumptions

Scenario	Customer charge	Tier 1 $/kWh	Tier 1 Usage	Tier 2 $/kWh	Tier 2 Usage	Tier 3 $/kWh	Tier 3 Usage
1	$5	$0.0800	0–500	$0.1204	501–1,000	$0.1504	>1,000
2	$25	$0.0702	0–500	$0.0803	501–1,000	$0.1101	>1,000

Table 14 shows the differences in payback periods in years under the five scenarios shown in table 12.

Table 14. Payback periods for measures and programs under Scenarios 1–5

Measure/program	Tiered $5 CC	Tiered $25 CC	Flat $5 CC	Flat $25 CC	Flat $50 CC
LED 40-watt replacement	0.99	1.35	1.38	1.80	2.92
LED 60-watt replacement	1.09	1.48	1.52	1.98	3.20
LED 75-watt replacement	1.54	2.11	2.16	2.82	4.55
Smart strip	1.56	2.14	2.18	2.85	4.61
Variable-speed pool pump	1.69	2.30	2.36	3.08	4.97
Advanced diagnostic tune-up	2.12	2.90	2.97	3.87	6.26
Equipment replacement with quality installation	3.81	5.20	5.32	6.95	11.23
Prescriptive duct repair	4.74	6.47	6.62	8.65	13.97
New construction ESTAR Homes v3.0—Tier 2	5.80	7.92	8.10	10.58	17.09
New construction total program	6.18	8.45	8.64	11.28	18.23
New construction ESTAR Homes v3.0	6.57	8.98	9.19	12.00	19.39
Duct test and repair	6.97	9.52	9.74	12.72	20.56
Attic insulation	7.79	10.64	10.89	14.22	22.97
Air sealing and attic insulation	8.67	11.84	12.12	15.82	25.56

CC = Customer charge

As table 14 shows, the changes in rate design significantly alter payback periods, especially for measures with higher incremental costs. Of the five scenarios, the low customer charge ($5 per month) and three-tiered rate structure (with either level of customer charge) offer the shortest payback periods. Payback periods more than doubled when customer charges moved from $5 to $50. Moving from a $5 to $25 monthly customer charge produced payback periods that were 31% longer; going from a $25 to $50 customer charge increases payback periods by 62%.

TIME-OF-USE RATE RESULTS

The next six scenarios are based on iterations of TOU rates using various levels of customer charges and differing ratios of on-to-off peak rates. Our TOU rate analysis used a five-hour on-peak time period of 3–8 pm on weekdays. Table 15 outlines the details of each scenario.

Table 15. TOU rate scenarios

Scenario	Customer charge ($/month)	On- to off-peak ratio	Summer off-peak ($/kWh)	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)
6	$5	2	$0.090	$0.181	$0.091	$0.181
7	$25	2	$0.073	$0.145	$0.065	$0.129
8	$5	3	$0.077	$0.232	$0.079	$0.238
9	$25	3	$0.062	$0.186	$0.057	$0.170
10	$5	4	$0.068	$0.270	$0.071	$0.283
11	$25	4	$0.054	$0.217	$0.050	$0.201

Table 16 shows the differences in payback periods under the six scenarios in table 15.

Table 16. Payback periods (years) for TOU rate design scenarios for various measures

Program/measure	$5 CC 2:1 ratio	$25 CC 2:1 ratio	$5 CC 3:1 ratio	$25 CC 3:1 ratio	$5 CC 4:1 ratio	$25 CC 4:1 ratio
LED 40-watt replacement	1.43	1.91	1.45	1.94	1.47	1.97
LED 60-watt replacement	1.57	2.09	1.59	2.13	1.62	2.17
LED 75-watt replacement	2.23	2.97	2.27	3.03	2.30	3.08
Smart strip	2.20	2.91	2.21	2.91	2.21	2.92
Variable-speed pool pump	2.26	2.83	2.21	2.76	2.17	2.72
Advanced diagnostic tune-up	2.84	3.56	2.78	3.48	2.73	3.42
Equipment replacement with quality installation	5.10	6.38	4.99	6.24	4.90	6.14
Prescriptive duct repair	6.34	7.94	6.20	7.76	6.10	7.64
New construction ESTAR Homes v3.0—Tier 2	8.08	10.46	8.08	10.44	8.08	10.46
New construction total program	8.62	11.16	8.62	11.14	8.62	11.16
New construction ESTAR Homes v3.0	9.17	11.87	9.17	11.85	9.17	11.87
Duct test and repair	9.34	11.68	9.13	11.42	8.98	11.24
Attic insulation	10.43	13.05	10.20	12.76	10.03	12.56
Air sealing and attic insulation	11.61	14.53	11.35	14.20	11.16	13.98

CC = Customer charge

Payback periods for TOU rate scenarios varied by measure. For some measures, such as LED lighting, payback periods increased when moving to higher on- to off-peak ratio rates. For other measures, such as attic insulation and duct test and repair, the payback periods declined when moving from 2:1 to 4:1 on- to off-peak ratio rates because large amounts of usage occurred outside the peak window. However the changes in payback periods were small when changing the on- to off-peak ratios. The largest shifts in payback periods were caused by higher customer monthly charges. Moving from a $5 to $25 customer charge increased payback periods by 25–34%, depending on the measure.

DEMAND CHARGE RATE RESULTS

The final set of scenarios we considered include a customer charge, demand charge, and volumetric energy rate. We constructed rates using three different customer charges ($5, $15, and $25) and three demand rates ($5, $7.50, and $10 per kW). Determining payback periods for demand charge rates is complicated by the way in which demand charges are billed. These charges are typically based on the customer peak demand in a 15- to 60-minute period of the month. The peak demand period typically must fall within a specified time window—such as noon to 7 pm on weekdays. The demand savings in the APS TRM are coincident peak savings, meaning that the demand reduction is what you could expect during the utility's system peak. Therefore it is very difficult to know whether or not the specific measure's demand savings will occur at that time and produce bill savings. For the purpose of this analysis, we assumed coincident peak demand reductions would amount to customer bill savings 50% of the time. We based this assumption on discussions with internal staff and other industry experts and believe it to be conservative.

Table 17 outlines the demand charge rate scenarios.

Table 17.Demand charge rate scenarios

Scenario	Customer charge ($/month)	Demand charge ($/kW)	Energy rate ($/kWh)
12	$5	$5	$0.0815
13	$15	$5	$0.0690
14	$25	$5	$0.0564
15	$5	$7.50	$0.0685
16	$15	$7.50	$0.0559
17	$25	$7.50	$0.0434
18	$5	$10	$0.0555
19	$15	$10	$0.0429
20	$25	$10	$0.0303

Table 18 shows the differences in payback periods under the nine scenarios in table 17.

Table 18. Payback periods (years) for demand charge rate design scenarios for various measures

Program/measure	$5 CC $5/kW	$15 CC $5/kW	$25 CC $5/kW	$5 CC $7.50/kW	$15 CC $7.50/kW	$25 CC $7.50/kW	$5 CC $10/kW	$15 CC $10/kW	$25 CC $10/kW
LED 40-watt replacement	1.79	2.11	2.57	2.10	2.55	3.26	2.54	3.23	4.45
LED 60-watt replacement	1.97	2.32	2.82	2.31	2.80	3.58	2.79	3.55	4.89
LED 75-watt replacement	2.79	3.29	4.01	3.28	3.99	5.08	3.96	5.05	6.95
Smart strip	2.63	3.06	3.65	2.92	3.46	4.25	3.29	4.00	5.09
Variable-speed pool pump	2.99	3.50	4.24	3.44	4.15	5.23	4.07	5.10	6.83
Advanced diagnostic tune-up	3.25	3.73	4.37	3.42	3.95	4.68	3.60	4.19	5.02
Equipment replacement with quality installation	5.03	5.65	6.45	4.89	5.48	6.23	4.76	5.32	6.02
Prescriptive duct repair	6.49	7.33	8.42	6.43	7.25	8.32	6.37	7.17	8.21
New construction ESTAR Homes v3.0—Tier 2	9.31	10.75	12.73	10.06	11.76	14.17	10.94	12.98	15.98
New construction total program	9.94	11.48	13.59	10.74	12.57	15.14	11.69	13.88	17.09
New construction ESTAR Homes v3.0	10.58	12.22	14.47	11.44	13.38	16.13	12.45	14.79	18.22
Duct test and repair	9.56	10.79	12.40	9.46	10.68	12.24	9.37	10.56	12.09
Attic insulation	12.70	14.71	17.47	13.86	16.28	19.73	15.25	18.23	22.67
Air sealing and attic insulation	14.44	16.78	20.02	15.97	18.88	23.08	17.86	21.58	27.26

Energy charges for these scenarios are shown in table 17.

Payback periods increase under demand rates for all measures when compared to flat, tiered, or TOU rates, especially when combined with a high monthly customer charge of $25. Even under a low customer charge, payback periods increase by 42% on average moving from a $5 to $10 per kW demand charge. Shifting cost recovery from volumetric to demand rates increased the payback period for all measures we reviewed. For measures with higher incremental costs, the increase in payback periods was substantial. For example, in a scenario with a $5 per kW demand charge, moving from a $5 to $25 customer charge increased payback periods for air sealing and attic insulation from 14.5 to 20 years. For a higher demand charge ($10 per kW), the result increased a 17-year payback to more than 27 years.

PAYBACK ANALYSIS CONCLUSIONS

Our analysis shows that changes in residential rate design alter payback periods for the measures we reviewed. As an example, figure 8 shows the payback periods for the residential new construction total program.

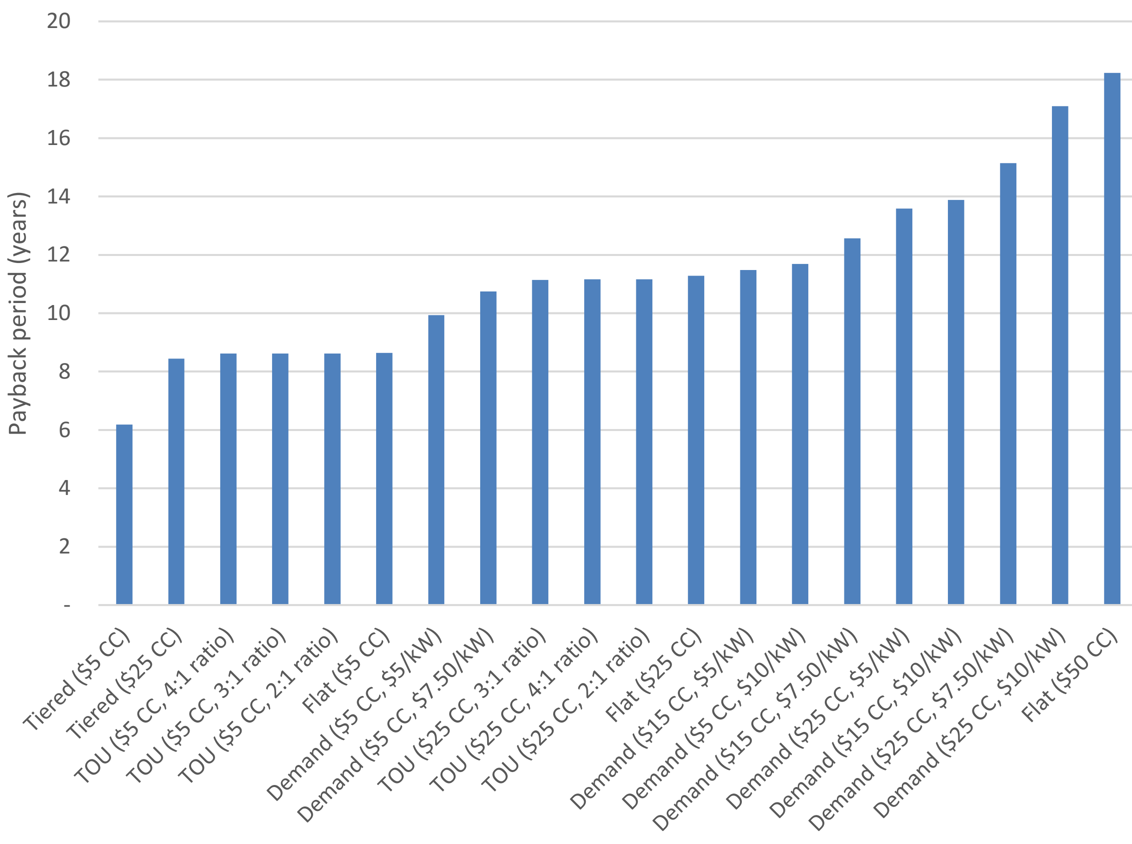

Figure 8. Residential new construction total program payback periods for various rate design scenarios

As the figure shows, the scenarios with the longest payback periods are those with higher customer charges (more than $25 per month) and demand charges. The scenarios with the lowest payback periods tended to be those with lower customer charges, tiered or flat rates, and TOU rates. Moving from a TOU or flat rate with a $5 customer charge to a demand rate with a $25 customer charge and a demand charge of $7.50 or $10 per kW doubled the payback period for this program. Moving from an inclining tiered rate with three tiers and a $5 customer charge to a flat rate with a $50 customer charge tripled the payback period.

Figure 9 shows the payback periods for replacing a 60-watt lamp with an LED.

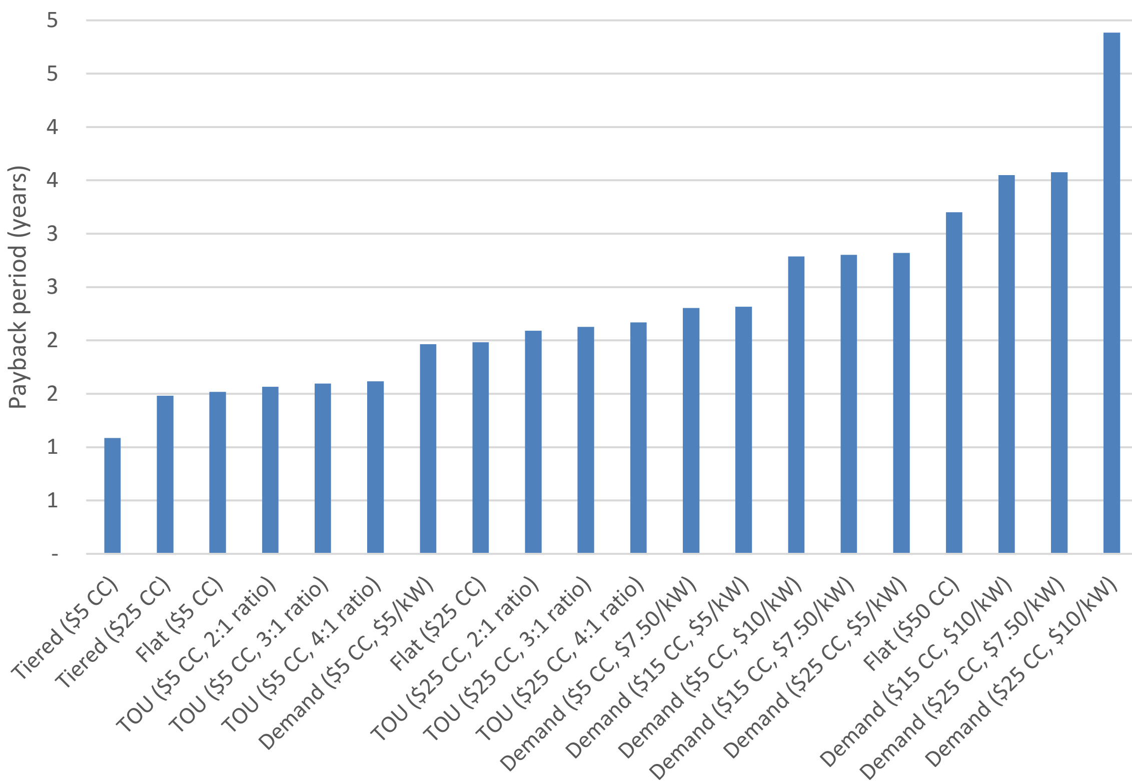

Figure 9. LED 60-watt replacement measure payback periods under various rate design scenarios

As figure 9 shows, the results here are similar: the rate designs with low monthly customer charges and tiered rates produce the shortest payback periods. TOU rates coupled with any level of customer charges performed well, with payback periods of approximately two years or less. Scenarios with demand charges performed poorly in payback periods; only the demand rate with a $5 monthly customer charge and $5 per kW demand charge fell under a two-year payback.

In all, rate design scenarios utilizing demand charges showed large increases in payback periods—often more than 30%—compared to flat or TOU rates. Scenarios focused on tiered rates showed the shortest payback periods, even when combined with a higher monthly customer charge. Scenarios with higher customer charges often increased payback periods, especially when combined with demand charges.

Rate Design Implications for Low-Income Customers

One policy consideration of ratemaking is the impact of proposed rates on low-income customers. Low-income customers have less ability to invest in energy efficiency and to respond to large rate swings. However low-income customers use relatively less energy during the peak hours, and their load profiles are often flatter than those of the average residential customer (Faruqui, Sergici, and Palmer 2010; Cappers et al. 2016b). Low-income customers may also use less electricity on average when compared with higher-income customers, although this may not be the case for all utilities.[14] In an analysis of 2009 data from the EIA's Residential Energy Consumption Survey, the National Consumer Law Center showed that electric consumption was lower for households under 150% of federal poverty guidelines in 26 of 27 regions nationally (Howat 2016).

If low-income customers tend to have lower usage, rate designs that recover more costs from lower usage customers could disproportionally affect them. In particular, utility proposals that significantly increase the customer charge are one form of rate design that disproportionately affects low-usage customers. Figure 10 shows the distributional impacts of a revenue neutral shift from a $5 monthly customer charge to $25. As the figure illustrates, low-usage customers are adversely affected. Customers using more than 800 kWh per month would see reductions in bills, while customers using less would experience bill increases.

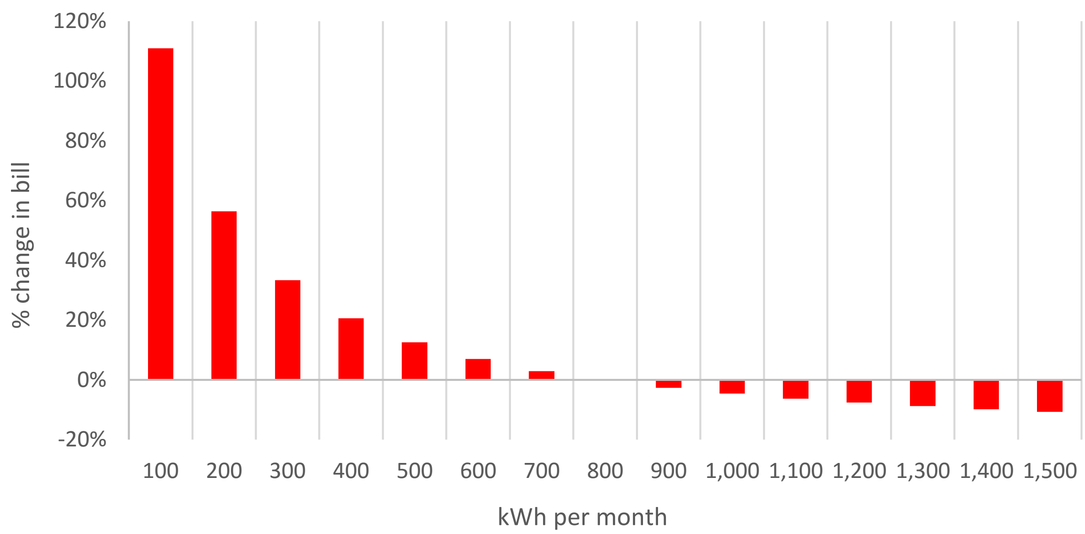

Figure 10. Distributional impacts for usage levels when shifting from a $5 customer charge per month to a $25 charge, based on data from table 8. Both rate options are revenue neutral.

EVIDENCE FROM PRICING PILOTS

Low-income customers often have a flatter usage profile, implying that any rate design structure with higher rates during peak hours could benefit them, even in the absence of behavioral or technological changes. Although most of the rate design pilots we reviewed did not specifically evaluate impacts on low- or limited-income customers, several did consider this issue.

[14] For example, residential customers on the low-income CARE for Pacific Gas and Electric rate use more electricity on average than customers not on CARE rates. Several factors explain this including: low-income customers live in hotter climate zones and have less energy-efficient homes. It is also important to consider that not all low-income customers are enrolled in low-income rates.

A recent Lawrence Berkeley National Laboratory report reviewed the experience of low-income customers with CPP rates using the results of two large pricing pilots in the Green Mountain Power (GMP) and Sacramento Municipal Utility District (SMUD) service territories. The study found that low-income customers in SMUD's service territory who had volunteered for the rate had lower average use levels during CPP events and were less responsive than other customers. However low-income customers under the default enrollment approach demonstrated a similar response to other customers. The study did not present changes on overall consumption, but it found bill impacts to be similar for low-income and higher-income populations. Finally, the study found that low-income customers did not report greater levels of discomfort or hardship while responding to the CPP events (Cappers et al. 2016b).

Under the SMUD SmartPricing Options study, low-income customers (those enrolled in the Energy Assistance Program rate) opted in and dropped out at a lower rate than other customers. Under the default TOU pricing plans, low-income customers showed very similar absolute and percentage load reductions. For default CPP and all opt-in plans, average load reductions for lower-income customers were less than other customers. The evaluation of the SmartPricing Options study also estimated price elasticities for low-income customers.[15] The analysis demonstrated that low-income customers were about 50% less responsive to changes in price than other customers (Jimenez, Potter, and George 2014).

Other studies in California show low-income customers are less responsive to changes in price. The California Statewide Pricing Pilot showed that CARE customers (those qualifying for bill assistance based on income criteria) showed very low price responsiveness (CRA 2005). Another evaluation of Pacific Gas & Electric's 2015 SmartRate CPP program shows that CARE customers demonstrated smaller demand reductions than other customers (Braithwait et al. 2016).

In phase 1 of the Oklahoma Gas & Electric Smart Study Together pilot, low-income participants demonstrated a higher percentage savings and higher demand savings than other income segments in some cases (GEP 2011). During the PECO Smart Time Pricing Pilot, low-income customers on TOU rates responded at a much higher rate than average accounts. Low-income customers—those with a household income under $34,000—had an average peak-load reduction of 7.3%, compared to 5.7% for all accounts (Bade 2015).

CONCLUSIONS ON LOW-INCOME CUSTOMERS AND RATE DESIGN

If low-income customers do have flatter load profiles than other customer groups, they could be favorably affected by TOU rates. Although some of these customers may still see increased bills, they could see lower bills than other customers with higher peak demand. Our review of a few studies documents this possibility, but this may not be the case for all utilities. Low-income customers have limited financial resources and lower levels of discretionary energy usage than other customers, which limits their ability to respond to

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[15] *Price elasticities* measure how much a customer will change consumption in response to a change in price, generally representing the percentage change in consumption based on a 1% change in price.

rate changes. They should be carefully targeted in any transition to new rates and offered programs, tools, and information to help them respond.

Summary of Findings

Large-scale technological shifts are stimulating changes in the electric utility industry. These changes are also driving a wide range of new rate structures for residential customers. Some aspects of recently proposed rate design, such as higher customer charges, diminish the price signal to customers to be energy efficient. This could adversely affect the achievement of energy efficiency goals, including by reducing customer motivation to participate in utility energy efficiency programs or make energy efficiency investments. As we outlined in our rate design principles, a primary objective should be to promote conservation and energy efficiency. Incentivizing energy efficiency offers benefits, and sending customers proper price signals to efficiently use electricity will reduce system costs in the long run by avoiding costly infrastructure investments.

Trends in rate design include increased utility proposals for higher customer charges; implementation of default TOU rates; increased attention to other dynamic rates, such as CPP, PTR, and VPP; and increased prevalence of residential three-part rates with demand charges. We also found strong customer opposition to higher customer charges and residential demand charges for the cases we reviewed.

A review of customer motivations shows that, while customers reduce consumption and participate in energy efficiency program for a variety of reasons, bill savings are the primary motivator. Changes in rate design can dramatically affect the potential bill savings and payback periods for many energy efficiency measures. Our analysis of 14 measures under 20 different rate design scenarios shows that demand charges increase payback periods—often more than 30%—compared with flat or TOU rates. Scenarios focused on tiered rates showed the shortest payback periods, even when combined with a higher monthly customer charge. TOU rates also demonstrated lower payback periods than demand charges or rates with higher customer charges.

Studies have long demonstrated the peak-load reduction effects of dynamic prices (Faruqui, Hledik, and Palmer 2012; Faruqui et al. 2016). While reducing peak demand is a valuable objective, changes in overall consumption are also very important. Our review of eight recent pricing pilots found that customers generally reduce overall consumption under time-varying rates.

A final important consideration of changes to rate design is the potential impact on low-income customers. Although low-income customers may lack the financial resources to invest in energy efficiency measures to avoid potential bill increases from rate changes, these customers have shown some ability to respond to dynamic rates. These customers also often have a flatter load profile, meaning that many could benefit financially from a TOU rate without any behavior change. The vulnerability of low-income customers makes it especially important for utilities to consider adverse impacts for those customers unable to reduce or shift their electricity usage.

Recommendations

ACEEE offers the following recommendations on energy efficiency and residential rate design options.

CUSTOMER CHARGES AND VOLUMETRIC RATES

ACEEE recommends limiting customer charges to include only costs associated with billing, customer service, meters, and service drops (also known as the *basic customer method*). This approach simplifies calculation of the customer charge, ensures equity, and provides a stronger price signal to conserve.

Our analysis demonstrates that, other things being equal, higher customer charges necessitate reduced volumetric rates. Lower volumetric rates can cause increases to overall consumption in the long term, thereby increasing the need for utility infrastructure to meet new demand. Higher customer charges also discourage the price signal for customers to engage in energy efficiency programs or make other energy efficiency investments. Finally, our payback period analysis showed that increased customer charges often adversely impacted payback periods for energy efficiency measures.

TIME-OF-USE RATES

ACEEE supports the implementation of TOU rates for residential customers as an alternative to higher customer charges and demand charges. TOU rates offer many advantages and send more accurate price signals to customers about the cost of electricity at specific times.

TOU rates provide many benefits, including reducing peak demand and more accurately collecting utility costs at the time they are incurred than most other rate options. TOU rates are also well understood by residential customers. Our review of recent pricing pilots shows that customers on TOU rates do not increase their overall consumption. The SMUD pricing pilot also indicated that customers who were defaulted into TOU rates were satisfied with the rates, did not opt out at high levels, and reduced peak demand at statistically significant levels. Low-income customers also seem to respond to TOU rates and, if these customers have a flatter load profile, they could benefit through lower bills. Finally, several states—including California, Massachusetts, and Arizona—are implementing default TOU rates for new customers.[16]

[16] For California, see California Public Utilities Commission Final Decision in Rulemaking 12-06-013 issued July 13, 2015 at docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF. For Massachusetts, see Massachusetts Department of Public Utilities Anticipated Framework for Time Varying Rates in D.P.U. 14-04-B on June 12, 2014 at 170.63.40.34/DPU/FileroomAPI//api/Attachments/Get/?path=14-04%2fOrder_1404B.pdf. For Arizona, see Arizona Corporate Commission Decision Number 75697 (Docket no. E-04204A-15-0142) Opinion and Order in UNS Electric General Rate Case, August 18, 2016 at docket.images.azcc.gov/0000172763.pdf.

DEMAND CHARGES

ACEEE strongly urges further analysis of residential customer response to and understanding of demand charges, potentially in the form of pilot studies.

The use of default or mandatory demand charges for residential customers should be approached with caution. As our review shows, little evidence exists on the implications of demand charges for overall customer consumption. Demand charges also seem to offer the smallest peak demand reductions among the rate designs we reviewed. Our research further demonstrates that demand charges produce the longest payback periods among all the energy efficiency measures we reviewed.[17] Finally, noncoincident demand charges are not cost based and do not align with customer cost of service, while coincident peak demand charges are virtually impossible to implement equitably. Unlike other dynamic price approaches, demand charges have yet to undergo rigorous pilots or pricing studies.

REVENUE DECOUPLING

ACEEE recommends the use of revenue decoupling as a policy to reduce the utility disincentive to promote efficiency and promote reduced sales, and also as a way to stabilize revenue.

While it is not a focus of this report, ACEEE has strongly supported revenue decoupling in the past and continues to recommend it. Many utility proposals for alterative rate design (especially higher customer charges) are responses to concerns about fixed cost recovery and revenue stability. Decoupling guarantees that utilities will recover commission-authorized revenues, thereby ensuring fixed cost recovery and stabilizing revenues. With this assurance, utilities can pursue rate design options that are more beneficial to customer interests.

[17] See the direct testimony of William Perea Marcus, filed on December 11, 2015 in PUC Docket No. 44941, Application of El Paso Electric Company to Change Rates. Also see Chernick et al. 2016 and Borenstein 2016 for a more detailed discussion of why demand charges are not cost based.

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Appendix A. Residential Customer Charge Results from Selected Rate Cases

Table A1 shows residential customer charge results for 87 selected rate cases from 2013 to the present, sorted by decision date. This list is not exhaustive.

Table A1. Residential customer charge results

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
NJ	Jersey Central Power and Light	$1.92	$2.99	$2.98	56%	55%	Dec-16
MD	Delmarva Power & Light	$7.94	$12.00	$9.43	51%	19%	Feb-17
KS	Empire District Electric	$14.00	$19.60	$14.00	40%	0%	Jan-17
MI	DTE Electric Company	$6.00	$9.00	$7.50	50%	25%	Jan-17
PA	Pennsylvania Power	$10.85	$13.41	$11.00	24%	1%	Jan-17
PA	West Penn Power	$5.81	$13.98	$7.44	141%	28%	Jan-17
PA	Metropolitan Edison	$10.25	$17.42	$11.25	70%	10%	Jan-17
PA	Pennsylvania Electric	$9.99	$17.10	$11.25	71%	13%	Jan-17
TX	Southwestern Public Service	$9.50	$10.50	$10.00	11%	5%	Jan-17
CA	Liberty Utilities	$7.10	$7.67	$6.56	8%	–8%	Dec-16
CT	United Illuminating Company	$17.25	$17.25	$9.67	0%	–44%	Dec-16
FL	Florida Light and Power	$7.87	$10.00	$7.87	27%	0%	Dec-16
ID	Avista Utilities	$5.25	$6.25	$5.75	19%	10%	Dec-16
ME	Emera Maine	$5.82	$6.31	$6.75	8%	16%	Dec-16
NC	Dominion North Carolina Power	$10.96	$13.48	$10.96	23%	0%	Dec-16
NV	Sierra Pacific Power Company	$15.25	$20.75	$15.25	36%	0%	Dec-16
SC	Duke Energy Progress	$6.50	$9.25	$9.06	42%	39%	Dec-16
WA	Avista Utilities	$8.50	$9.50	$8.50	12%	0%	Dec-16
CO	Xcel Energy CO	$7.71	$5.78	$5.39	–25%	–30%	Nov-16
CO	Black Hills Energy	$16.50	$18.62	$16.50	13%	0%	Nov-16
MD	PEPCO	$7.39	$12.00	$7.60	62%	3%	Nov-16
WI	Wisconsin Power and Light	$7.67	$18.00	$15.00	135%	96%	Nov-16
TN	Kingsport Power Company	$7.30	$11.00	$12.63	51%	73%	Oct-16
MA	Massachusetts Electric Co	$4.00	$20.00	$5.50	400%	38%	Sep-16
MI	Upper Peninsula Power	$12.00	$15.00	$15.00	25%	25%	Sep-16
MO	KCP&L MO	$9.54	$14.50	$10.43	52%	9%	Sep-16
NM	Public Service Co. of New Mexico	$5.00	$13.00	$7.00	160%	40%	Sep-16
AZ	UNS Electric	$10.00	$20.00	$15.00	100%	50%	Aug-16

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
MO	Empire District Electric	$12.52	$14.47	$13.00	16%	4%	Aug-16
NJ	Atlantic City Electric Company	$4.00	$6.00	$4.44	50%	11%	Aug-16
NM	Southwestern Public Service	$7.90	$9.95	$8.50	26%	8%	Aug-16
TX	El Paso Electric	$5.00	$10.00	$6.90	100%	38%	Aug-16
IN	NIPSCO	$11.00	$20.00	$14.00	82%	27%	Jul-16
TN	Entergy Arkansas	$6.96	$8.40	$8.40	21%	21%	Jul-16
MD	Baltimore Gas & Electric	$7.50	$12.00	$7.90	60%	5%	Jun-16
NM	El Paso Electric	$7.00	$10.00	$7.00	43%	0%	Jun-16
NY	New York State Electric and Gas	$15.11	$18.89	$15.11	25%	0%	Jun-16
NY	Rochester Gas & Electric	$21.38	$26.73	$21.38	25%	0%	Jun-16
IN	Indianapolis Power & Light	$11.00	$17.00	$17.00	55%	55%	Mar-16
MT	Montana-Dakota Utilities	$5.40	$7.50	$5.40	39%	0%	Mar-16
AR	Entergy Arkansas	$6.95	$9.00	$8.43	29%	21%	Feb-16
WA	Avista Utilities	$8.50	$14.00	$8.50	65%	0%	Jan-16
ID	Avista Utilities	$5.25	$8.50	$5.25	62%	0%	Dec-15
MI	DTE Electric Company	$6.00	$10.00	$6.00	67%	0%	Dec-15
PA	PECO	$7.09	$12.00	$8.45	69%	19%	Dec-15
TX	Southwestern Public Service	$7.50	$9.50	$9.50	27%	27%	Dec-15
WI	Xcel Energy	$8.00	$18.00	$14.00	113%	87%	Dec-15
MI	Consumers Energy	$7.00	$7.50	$7.00	7%	0%	Nov-15
OR	Portland General Electric	$10.00	$11.00	$10.50	10%	5%	Nov-15
PA	PPL	$14.09	$20.00	$14.09	42%	0%	Nov-15
SD	NorthWestern Energy	$5.00	$9.00	$6.00	80%	20%	Nov-15
WI	Wisconsin Public Service	$19.00	$25.00	$21.00	140%	83%	Nov-15
NY	Orange & Rockland	$20.00	$25.00	$20.00	25%	0%	Oct-15
KS	KCP&L	$10.71	$19.00	$14.00	77%	31%	Sep-15
KS	Westar	$12.00	$27.00	$14.50	125%	21%	Sep-15
MO	KCP&L	$9.00	$25.00	$11.88	178%	32%	Sep-15
MI	Indiana Michigan Power	$7.25	$9.10	$7.25	26%	0%	Aug-15
CA	Pacific Gas & Electric Company	$-	$10.00	$-	0%	0%	Jul-15
CA	San Diego Gas & Electric	$-	$10.00	$-	0%	0%	Jul-15
CA	Southern California Edison	$0.95	$10.00	$0.95	953%	0%	Jul-15
SD	MidAmerican	$7.00	$8.50	$8.00	21%	14%	Jul-15

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
KY	Kentucky Utilities Company	$10.75	$18.00	$10.75	67%	0%	Jun-15
KY	Louisville Gas-Electric	$10.75	$18.00	$10.75	67%	0%	Jun-15
KY	Kentucky Power	$8.00	$16.00	$11.00	100%	38%	Jun-15
MO	Empire District Electric	$12.52	$18.75	$12.52	50%	0%	Jun-15
NY	Central Hudson Gas & Electric	$24.00	$30.00	$24.00	25%	0%	Jun-15
NY	Consolidated Edison	$15.76	$18.00	$15.76	14%	0%	Jun-15
MN	Xcel Energy	$8.00	$9.25	$8.00	16%	0%	May-15
WV	Appalachian Power/Wheeling	$5.00	$10.00	$8.00	100%	60%	May-15
MI	Xcel Energy	$8.65	$8.75	$8.75	1%	1%	Apr-15
MI	Wisconsin Public Service	$9.00	$12.00	$12.00	33%	33%	Apr-15
MO	Ameren	$8.00	$8.77	$8.00	10%	0%	Apr-15
OK	Public Service Co. of Oklahoma	$16.16	$20.00	$20.00	24%	24%	Apr-15
PA	Pennsylvania Power	$8.89	$12.71	$10.85	43%	22%	Apr-15
PA	West Penn Power	$5.00	$7.35	$5.81	47%	16%	Apr-15
PA	Metropolitan Edison	$8.11	$13.29	$10.25	64%	26%	Apr-15
PA	Pennsylvania Electric	$7.98	$11.92	$9.99	49%	25%	Apr-15
WA	PacifiCorp	$7.75	$14.00	$7.75	81%	0%	Mar-15
CT	Connecticut Light & Power	$16.00	$25.50	$19.25	59%	20%	Dec-14
MD	Baltimore Gas & Electric	$7.50	$10.50	$7.50	40%	0%	Dec-14
WI	Madison Gas and Electric	$10.29	$68.00	$19.00	113%	87%	Dec-14
VA	Appalachian Power Co	$8.35	$16.00	$8.35	92%	0%	Nov-14
WI	We Energies	$9.13	$16.00	$16.00	75%	75%	Nov-14
WI	Wisconsin Public Service	$10.40	$25.00	$19.00	140%	83%	Nov-14
NV	Nevada Power	$10.00	$15.25	$12.75	53%	28%	Oct-14
ME	Central Maine Power Company	$5.71	$20.00	$10.00	250%	75%	Aug-14
UT	Rocky Mountain Power	$5.00	$8.00	$6.00	60%	20%	Aug-14
	Average	**$9.09**	**$14.64**	**$10.48**	**61%**	**15%**	
	Median	**$8.00**	**$13.00**	**$9.67**	**63%**	**21%**	

Appendix B. Pricing Study Details

This appendix describes the pricing pilot studies we reviewed. Table B1 gives a brief overview of each pilot or pricing program.

Table B1. Pricing studies reviewed

Pricing study	Years	Utility	State / province	Rates
myPower Pricing Pilot	2006–2007	PSEG	NJ	TOU, CPP
SmartGridCity™	2010–2013	Xcel	CO	TOU, CPP, PTR
SmartPricing Options	2011–2103	SMUD	CA	TOU, CPP
Ontario Smart Price Pilot	2006–2007	OEB	ON	TOU, CPP, PTR
Consumer Behavior Study	2012–2013	GMP	VT	CPP, PTR
EnergySense CPP Pilot	2011–2012	MMLD	MA	CPP
Smart Energy Pricing Pilot	2008	BGE	MD	CPP, PTR
Consumer Behavior Study	2010–2012	OG&E	OK	VPP, TOU+CPP
Energy Smart Pricing Plan	2003–2005	CEC	IL	RTP
Power Smart Pricing	2007–current	Ameren	IL	RTP
Res Real-time Pricing	2007–current	ComEd	IL	RTP
PowerCents DC	2007	PEPCO	DC	CPP, PTR, RTP

PSEG myPower Pricing Pilot Program, 2006–2007

This pricing pilot targeted residential customers with a TOU rate combined with CPP. One group received educational materials (education group), while the other received education and a programmable thermostat (technology group). Within the education group, the treatment groups were split between those with and without central air-conditioning. The study also relied on hourly data from a control group to estimate energy and peak demand savings. Several CPP events were called during the pilot timeframe including: two in summer 2006, five in summer 2007, and three in non-summer months of 2007. The impact analysis for this pilot estimated peak demand and energy savings impacts from both the TOU and CPP. Table B2 shows the pilot's demand savings results. Peak demand reductions did occur in the winter months, but at a much smaller rate than in the summer.

Table B2. myPower Pricing Pilot demand reduction results by rate type

	TOU only		CPP only		Total	
Customer group	kW	%	kW	%	kW	%
Technology	0.59	21%	0.74	26%	1.33	47%
Education w/central AC	0.07	3%	0.36	14%	0.43	17%
Education w/o central AC	0.09	6%	0.23	14%	0.32	20%

The program evaluation also demonstrated energy savings from the TOU rate. The most significant savings occurred in the summer months, but minimal savings were also shown in the winter months. Table B3 shows the savings from the summer months.

Table B3. myPower Pricing Pilot summer energy savings

Customer group	Summer energy savings from TOU	
	kWh per customer	%
Technology	139	3.3%
Education w/central AC	144	3.7%
Education w/o central AC	127	4.3%

The study also evaluated winter and shoulder period changes in consumption. The evaluation demonstrated very little kWh shifting or energy savings for any customer groups during winter months and shoulder periods. The only significant change was a 1.65% decrease in energy use during winter months by the myPower Sense group with central air-conditioning (statistically significant at the 90% confidence level).

Xcel SmartGridCity™ Pricing Pilot (Boulder), 2010–2013

Xcel Energy conducted this pricing pilot in Boulder, Colorado, from October 2010 to September 2013 to better understand how customers responded to various rate structures. Customers were able to opt in to three different rate options: PTR, CPP, or TOU. The program was targeted to customers with AMI meters installed in the City of Boulder in two phases during the three-year period. Each phase represented a different group of customers. A small subset of program participants was given in-home smart devices, but not enough customers received the devices to generalize results to a broader population. Evaluation of the pilot showed that customers did respond to rates by reducing overall usage and reducing demand during peak hours and events (Enernoc 2013).

Each year, pilot participants enrolled in two phases. Phase 1 participants opted in to the rate. Phase 2 participants were selected at random and then given a choice between three time-varying rates and the standard rate. Although customers were given a choice, if they did not choose, they were ultimately placed on the standard rate, making this option not a true opt-out rate.

Table B4 shows the estimated demand savings from each rate type; results are presented by season or type of customer. Some customers on TOU rates were also enrolled in the Saver's Switch program, an air-conditioning load management program. These customers are noted by "SS" for Saver's Switch or "NSS" for non-Saver's Switch.

Table B4. SmartGridCity peak demand reduction results by rate type

Rate type	Description	2011 Ph. 1	2011 Ph. 2	2012 Ph. 1	2012 Ph. 2	2013 Ph. 1	2013 Ph. 2
CPP	Average summer event day	29%	26%	26%	23%	22%	13%
CPP	Average non-summer event day			24%	14%	16%	8%
PTR	Average summer event day	14%	12%	8%	8%	8%	8%
PTR	Average non-summer event day			5%	3%	5%	2%
TOU	Average summer weekday (SS)	8%	9%	6%	7%	7%	5%
TOU	Average non-summer weekday (SS)	2%		–1%	1%	1%	1%
TOU	Average summer weekday (NSS)	9%	6%	7%	5%	5%	3%
TOU	Average non-summer weekday (NSS)	1%		4%	3%	4%	3%

The table demonstrates the significant peak demand reductions from each rate. Demand reductions decline year to year, indicating a drop off in persistence. Table B5 shows the overall energy savings for each rate type.

Table B5. SmartGridCity annual energy savings results by rate type

Rate Type	2011 Ph. 1	2011 Ph. 2	2012 Ph. 1	2012 Ph. 2	2013 Ph. 1	2013 Ph. 2
CPP	5%		8%	2%	10%	1%
PTR	3%		6%	3%	6%	4%
TOU SS	0%		–1%	0%	0%	0%
TOU NSS	–2%		0%	2%	0%	2%

Negative values show increases in consumption.

Overall decline in energy consumption was present in all three rate types, but it was much smaller in TOU than in CPP and PTR. In two instances, energy consumption increased for customers on TOU rates. TOU SS customers did decrease consumption during peak periods, but increased consumption at off-peak times. Overall, CPP customers demonstrated the strongest price response for demand and energy consumption. PTR customers reduced overall consumption, even during non-event times.

Baltimore Gas & Electric Smart Energy Pricing Pilot, 2008

Baltimore Gas & Electric (BGE) implemented this pilot in summer 2008 to test customer response to TOU+CPP and PTR. The pilot included one TOU+CPP rate and two PTR variations—one awarding a rebate of $1.16/kWh and the other awarding $1.75/kWh. Two technologies were also included in this pilot: the Energy Orb (a device that emits various colors to signal different prices) and an air conditioner switch that allows BGE to cycle the customer's air conditioner during a peak event. These variations produced eight different treatments. All treatment groups were voluntary participants. Evaluation of this pilot estimated hour-specific substitution and daily price elasticities to determine load reductions by period.[18] Table B6 shows the impact evaluation results from all eight treatment groups for critical days peak reduction and total consumption change for the entire month (Faruqui and Sergici 2009).

Table B6. BGE Smart Energy Pricing Pilot impact estimates

Rate design	Enabling technology	Critical days peak reduction	Overall energy savings
TOU+CPP	None	20.11%	–0.94%
TOU+CPP	Energy Orb and AC switch	32.54%	–1.16%
PTRL	None	17.82%	0.50%
PTRL	Energy Orb only	23.03%	0.50%
PTRL	Energy Orb and A/C switch	28.48%	0.50%
PTRH	None	20.94%	0.63%
PTRH	Energy Orb only	26.83%	0.63%
PTRH	Energy Orb and A/C switch	32.95%	0.63%

PTRL = Peak-time rebate low. PTRH = peak-time rebate high.

The evaluation demonstrated substantial reductions in use during peak events, but also increased usage during off-peak hours. It is unclear in the evaluation how much of the increased consumption in off-peak hours was "snapback"—that is, a spike in usage following an event. Total consumption changes were positive for CPP+TOU rates, meaning that customers increased usage overall. Finally, the evaluation demonstrated that the rates produced a stronger response to price when combined with technology.

Sacramento Municipal Utility District Smart Pricing Options Study, 2011–2013

The SMUD Smart Pricing Options consumer behavior pilot is one of the most well-known recent pricing experiments. SMUD implemented this pilot as part of the Department of Energy's Smart Grid Investment Grant program to test both customer response to dynamic pricing and the use of information to induce behavior change (Jimenez, Potter, and George 2013).[19] The SMUD study included seven treatment groups using: three rate design variations (a two-period TOU rate with a 4–7 pm peak period, a CPP combined with an inclining tiered rate, and a CPP price combined with a TOU rate); default or opt-in enrollment; and the offer of an IHD device. The pilot began in October 2011 and was in effect June–September in 2012 and 2013. Attrition from the pilot was higher than expected

[18] The evaluation also determined load reductions for three weather scenarios (mild, average, and extreme). For this report, we show only impacts based on average weather.

[19] A total of 11 utilities participated in consumer behavior studies focused on the integration of smart grid technologies and price response. More details of this initiative can be found at smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html.

due to more people moving than expected; the actual dropout rates were low at 4–9% over the two-year pilot (Jimenez, Potter, and George 2014).

Table B7 shows the load impacts and energy savings changes for the seven treatments. Each estimate is for all evaluation periods.

Table B7. SMUD Smart Pricing Options load reductions and energy savings estimates

Treatment group	CPP day impact	Average weekday impacts	Energy savings
Opt-in TOU/IHD offer	13.1%	11.9%	0.9%
Opt-in TOU/no IHD offer	10.1%	9.4%	1.1%
Opt-in CPP/IHD offer	25.1%	n/a	3.5%
Opt-in CPP/no IHD offer	20.9%	n/a	–1.0%
Default TOU/IHD offer	5.9%	5.8%	1.3%
Default CPP/IHD offer	14.0%	n/a	2.6%
Default TOU+CPP/IHD offer	12.3%	8.7%	1.3%

Evaluation of the pilot showed measurable load impacts from all seven treatment groups. The results also show energy savings from all seven treatments. The TOU treatment group energy savings were not statistically significant at the 95% confidence level. However the insignificant energy savings values in table B7 are evidence of savings because of a demonstrated lack of load shifting from peak to off-peak hours. These values also show no increase in consumption in off-peak hours during lower prices. For the CPP treatment group, both the opt-in CPP IHD offer and default CPP IHD offer groups demonstrated large reductions during peak periods but also statistically significant reductions in the pre-event period (Jimenez, Potter, and George 2014).

The study also focused on persistence of usage reductions. For most pricing options, the change in demand reduction from one summer to another was not statistically significant. Two pricing plans showed statistically significant changes in persistence from year to year: the opt-in TOU with IHD showed a decline in demand reduction, while the default CPP pricing plan showed an increase. This may suggest an initial learning curve, and that customers come to better understand the pricing and develop strategies to respond over time. More education and recommended strategies up front might shorten the learning curve.

The SMUD Smart Pricing Options produced several key findings. According to an LBNL study, enrollment rates were five times higher under the default enrollment, and once customers were enrolled, dropout rates were very low. Also, when considering the demand reductions for the default treatment groups, 20% of the entire consumer population was highly unengaged and inattentive (these customers did not provide any measurable energy savings in response to the TOU rate). These are the customers who need the most attention to not be worse off with this rate. Utilities should target these customers in a default TOU rollout. Finally, LBNL found no evidence of dramatic dissatisfaction between default and opt-in customers (Cappers et al. 2016a).

Ontario Energy Board Smart Price Pilot (Ontario, Canada), 2006–2007

The Ontario Energy Board, the electricity regulator of the Ontario province, conducted a pilot between August 2006 and March 2007 to better understand how residential customers responded to three different pricing structures: an existing TOU rate, a TOU with a CPP, and a TOU with a PTR. This pilot utilized AMI meters, but did not use any other technological interventions. Customers under all three rate structures responded by shifting load and reducing overall consumption (IBM 2007). Table B8 displays the peak demand and conservation results. These results are for the entire seven-month period.

Table B8. Ontario Energy Board Smart Price Pilot peak-shifting and conservation results

Program	Shift as % of critical-peak hours	Shift as % of all peak hours	% reduction in overall consumption
TOU	5.7%[1]	2.4%[2]	6.0%
TOU+CPP	25.4%	11.9%	4.7%[3]
TOU+PTR	17.5%	8.5%	7.4%

[1,2] Not statistically significant at the 90% level and cannot be generalized to larger population.
[3] Not statistically significant at the 90% level, but is significant at an 88% confidence level.

Green Mountain Power Pilot (Vermont), 2012–2013

Green Mountain Power conducted a pilot from fall of 2012 to summer of 2013 to assess how customers would respond to CPP and PTR. Four events were called in September 2012 and 10 in summer 2013. Each event occurred between 1 pm and 6 pm. Some customers in each treatment group were also given IHDs, which provide customers with real-time information on pricing and usage. Subsequent impact evaluation found that while no treatment group exhibited consistent responses over the 14 events, customers on average did reduce consumption during critical-peak events (5.3–15% for CPP and 3.8–8.1% for PTR) (Blumsack and Hines 2015).

Evaluation results also indicated that customers with IHDs showed a higher price response than other customers. These customers exhibited higher demand reductions during peak events and also reduced overall consumption at a higher rate than those without IHDs, by about 4%. Subsequent surveys of customers with IHDs showed that education in how to use the devices was critical. Finally, the study demonstrated a lack of persistence among customers, questioning the program's ability to serve as a capacity resource for the region (Blumsack and Hines 2015).

Oklahoma Gas & Electric Consumer Behavior Study, 2010–2012

Oklahoma Gas & Electric (OG&E) administered a two-year pricing pilot to evaluate the price response of customers on time-varying rates. The first phase of the pilot was conducted in 2010 and included 3,000 participants. The second phase began in 2011 and added an additional 3,000 customers. Participants were placed on either a VPP rate or a TOU rate with a critical-peak price component. The variable-peak price uses four defined price levels to replace the on-peak rate in the TOU. The variable price signal applies to the five-hour peak period on a weekday and is communicated to customers by 5 pm on the prior day. Participants were also given various technologies, including programmable communicating thermostats (PCTs), IHDs, access to a web portal, or all three (GEP 2011). Table B9 shows the rates used for both rate treatments.

Table B9. OG&E 2010 Phase 1 pricing pilot rates ($ per kWh)

Component	VPP+CPP	TOU+CPP
Off-peak/low	$0.045	$0.042
Standard	$0.113	$0.23
High	$0.23	$0.23
Critical	$0.46	$0.23
Critical price event	$0.46	$0.46

Source: GEP 2011

During Phase 1, both VPP and TOU+CPP rate groups demonstrated statistically significant load reductions under all technology scenarios. During non-event days, the most significant reductions were during peak times, but the TOU+CPP group also reduced usage in peak hours in most technology variations, except for the PCT group on the weekend. This is likely explained by the fact that the PCT group included those with only central air-conditioning. For the first year during off-peak hours, usage dropped for all TOU+CPP and all but PCT VPP+CPP groups on the weekends. Customers with IHD showed the largest decrease in usage. In the second year, off-peak consumption increased for all groups except those with web portal only. The net change in consumption was still negative though because the increase was less than the decrease in on-peak consumption (GEP 2012).

The VPP+CPP group exhibited demand reductions that corresponded with changes in the variable rate. Many technology variations within the VPP+CPP group showed an increase in off-peak consumption, but this was offset by higher on-peak reductions. The average change in off-peak consumption was negative for both rate treatments during non-event days and the decrease in energy usage was strongest for those with IHDs. Weather during event days was mild and savings were smaller, but still statistically significant for most groups (GEP 2011). Table B10 shows the changes in on- and off-peak consumption during year 1 for non-event days.

Table B10. Non-event day residential changes in consumption

Rate design	On-peak reduction in consumption	Off-peak reduction in consumption
TOU+CPP weekend		0.51% to 6.93%
TOU+CPP weekday	10.03% to 25.73%	5% to –3.42%
VPP+CPP weekend		1.32% to –1.31%
VPP+CPP low weekday	12.94% to 14.85%	11.75% to –2.01%
VPP+CPP standard weekday	6.37% to 23.97%	0.16% to –5.43%
VPP+CPP medium weekday	7.92% to 31.41%	–1.41% to –8.85%
VPP+CPP high weekday	10.99% to 34.95%	–0.97% to –8.39%

Range represents the four technology treatments. Negative numbers show an increase in consumption.

During Phase II, OG&E added an additional 3,000 residential participants and included small commercial customers. The TOU+CPP customers recruited in the second year showed statistically significant load reductions only for the PCT and three-technologies groups; in Phase I, load reductions were present for all technology groups. The VPP+CPP group exhibited similar behavior in year two, showing a strong positive relationship between price and load reduction. Finally, the evaluation found that the three-technologies group demonstrated load reductions throughout the day and during peak periods, showing potential behavior changes from the web portal and IHD in addition to automated savings from PCT (GEP 2012).

This pilot was so successful that, in 2016, OG&E rolled out time-varying rates to more than 120,000 customers (20% of its total customers) to defer investment in 170 MW of new generating capacity (DOE 2013a).

Marblehead ENERGYSENSE CPP Pilot, 2011–2012

Marblehead Municipal Light Department conducted a two-year CPP pilot in 2011 and 2012. This pilot, called EnergySense, relied on a pricing structure of a flat rate of $0.09/kWh and a CPP rate of $1.05/kWh. The control group in this study was charged a flat rate of $0.14/kWh. All CPP events were six hours in duration and called only during the summer months of June, July, and August. All participants were given access to a web portal containing information related to real-time consumption, historical usage, and current monthly bill estimates. In the second year, customers with central air-conditioning were given Wi-Fi-enabled programmable thermostats, customers with electric water heaters were given load switches, and customers with both were given both (GDS 2013b). Table B11 shows the evaluated estimates of the pilot's effect.

Table B11. EnergySense CPP Pilot results 2011–2012

Year	Average reduction in consumption over all summer months	Average hourly reduction in consumption during events	Program reduction in consumption on system coincident peak demand
2011	0.3%	36.7%	0.8%
2012	0.3%	21.3%	0.9%

The table shows a strong response from customers during peak events. The evaluation also demonstrated a reduction in overall usage during summer months and a decline in the system coincident peak demand. The program evaluation also documented a statistically significant difference between the response in year one and year two, but did not infer the participants suffered from program fatigue.[20] Finally, while technologies were offered as part of the program, difficulty with customer installations prevented a sample size large enough for worthwhile analysis (GDS 2013b).

Community Energy Cooperative Energy-Smart Pricing Plan (Illinois), 2003–2005

The Energy-Smart Pricing Plan (ESPP) began in 2003 with 750 customers, growing to 1,400 participants at the end of three years. The real-time price offered is based on the day-ahead wholesale market price. Customers are notified via email or phone if the price exceeds 10 cents/kWh. In the first two years of the program, customers responded to prices but weather was mild. The most significant response was when prices exceeded 10 cents/kWh, with consumption sometimes decreasing by more than 25% in the first hour. Multifamily customers also exhibited the largest response among residential customers. Lower-income households also exhibited high levels of response (Tholin et al. 2004, Isaacson et al. 2006).[21] The trend of lower-income households responding at greater levels than high-income households was consistent throughout the first three years. At the end of year three, independent evaluation also demonstrated that participants reduced overall usage in the summer months by 3% (Summit Blue 2006). Table B12 shows price elasticities for the program annually. Negative elasticities represent a reduction in usage in response to the program.

[20] Program fatigue is a reduced response from year to year or event to event.

[21] The details of high price response by low-income customers in this study were unclear because it is not certain whether low-income customers were curtailing use of essential energy services in response to price signals.

Table B12. ESPP annual elasticities 2003–2006

Year	Overall elasticity	Other key elasticities
2003	−0.042	
2004	−0.080	
2005	−0.047	−0.067 for air-conditioning cycling
2006	−0.047 when prices below $0.13/kWh −0.082 when prices above $0.13/kWh	−0.098 for air-conditioning cycling −0.067 for PriceLight

PriceLight is an IHD device that changes colors as energy prices change to alert customers to modify behavior. *Source:* Summit Blue 2006, p. 10.

Ameren Illinois Power Smart Pricing (Illinois), 2007–current

Ameren Illinois has offered an RTP program since 2007. This program, administered by Elevate Energy, sends participants high-price alerts the evening before a day where hourly electricity prices are at or above 9 cents/kWh. These alerts are sent through email, phone call, or text message. Prices are based on the day-ahead hourly Midcontinent Independent System Operator (MISO) market prices. At the end of 2015, this program had more than 10,500 participants (Elevate Energy 2016).

The 2015 Annual Report presented several key findings for program year 2014. When asked what actions were taken to reduce or shift energy usage, 12% of customers responded that they invested in whole home energy efficiency. A large percentage (27–32%) also reported behavioral changes, such as turning off the lights or adjusting the temperature setting. Program participants were able to save money on bills in nearly every year of this program. The evidence of changes to overall consumption are mixed. There were no average annual energy savings from 2008–2010. Instead, customers showed an average increase in annual consumption of 0.2%, with the largest increase during the winter months (9.2%) and a decrease in the other three seasons. For the period 2011–2014, annual usage was reduced 0.7% for regular customers and 0.6% for electric space heating customers (Elevate Energy 2015).[22]

PEPCO PowerCents DC (District of Columbia), 2007

The PowerCents DC program was initiated in 2007 as part of a smart meter pilot program intended to test customer response to dynamic pricing, smart meters, and smart thermostats. The program included nearly 900 resident participants taking service under CPP, critical-peak rebate, or hourly pricing. The program ran from summer 2008 through summer 2009. Changes in overall consumption were not measured as part of this experiment, but peak demand reductions were present in all three pricing structures. The response from hourly pricing was the lowest among the three pricing options, primarily because the prices were much higher under CPP and critical-peak rebates. Market

[22] From the annual report, it is unclear if this result is statistically significant.

conditions reduced the hourly prices, thereby reducing the response. Hourly pricing customers showed the highest bill savings from the program, with an average bill savings of 39%, primarily due to lower wholesale prices resulting from the Great Recession.

Commonwealth Edison Residential Real-Time Pricing Program (Illinois), 2007–present

Commonwealth Edison (ComEd) has offered an hourly RTP program to residential customers since 2007. The program relies on sending customers a day-ahead price alert if energy prices exceed a certain threshold (currently, 14 cents per kWh) through a variety of channels including email, phone, and text. Ten thousand residential customers are currently enrolled in the program.

Since inception, customers have saved money on energy costs, with the exception of 2014. The program has no price caps on the cost of electricity, and extreme weather in the first three months of 2014 caused much higher prices than average. The eight-year supply cost savings average is 19.4%, but in 2014 the annual supply savings was –4.7% (Becker 2015). The program has also undergone regular evaluations. A 2013 evaluation demonstrated price response, showing that, in response to an hourly 10% average price increase, consumption decreased by 0.5–1.5% (Becker 2015). The evaluation also showed a reduction in annual overall usage of 4% from 2007–2010. The reduction in overall usage was higher in the summer and lower in the winter, which was expected because prices were higher in the summer. During the extreme weather events of 2014, the reduction in overall consumption was more than 14% from January 8 through March 31. During this period, there was no significant load shifting, just reductions in overall use (Becker 2015).

Appendix C. Pricing Pilot Observations

Table C1 lists pricing pilot details for the 50-treatment observation used in figure 4, showing the distribution of reduction in overall consumption statistics for the pricing studies reviewed.

Table C1. Pricing pilot details for the 50-treatment observation used in figure 4

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
myPower Pricing Pilot	Technology	TOU CPP	Smart thermostat	Opt in	2007	Summer	47%	3%
myPower Pricing Pilot	Education w/ central AC	TOU CPP	None	Opt in	2007	Summer	17%	4%
myPower Pricing Pilot	Education w/o central AC	TOU CPP	None	Opt in	2007	Summer	20%	4%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2011	Annual	29%	5%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2011	Annual	14%	3%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2011	Annual	8%	0%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2011	Annual	9%	2%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2012	Annual	26%	8%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2012	Annual	8%	6%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2012	Annual	6%	1%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2012	Annual	–1%	0%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2013	Annual	22%	10%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2013	Annual	8%	6%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2013	Annual	7%	0%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2013	Annual	5%	0%
SmartGridCity	CPP Phase II	CPP	None	Opt in	2012	Annual	23%	2%
SmartGridCity	PTR Phase II	PTR	None	Opt in	2012	Annual	8%	3%
SmartGridCity	TOU w/ SS Phase II	TOU	None	Opt in	2012	Annual	7%	0%
SmartGridCity	TOU w/o SS Phase II	TOU	None	Opt in	2012	Annual	5%	2%
SmartGridCity	CPP Phase II	CPP	None	Opt in	2013	Annual	13%	1%
SmartGridCity	PTR Phase II	PTR	None	Opt in	2013	Annual	8%	4%
SmartGridCity	TOU w/ SS Phase II	TOU	None	Opt in	2013	Annual	5%	0%
SmartGridCity	TOU w/o SS Phase II	TOU	None	Opt in	2013	Annual	3%	2%
Smart Energy Pricing Pilot	TOU+CPP	TOU CPP	None	Opt in	2008	Summer	20%	–1%

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
Smart Energy Pricing Pilot	TOU+CPP w/tech	TOU CPP	EnergyOrb, AC switch	Opt in	2008	Summer	33%	–1%
Smart Energy Pricing Pilot	PTR low	PTR	None	Opt in	2008	Summer	18%	1%
Smart Energy Pricing Pilot	PTR low	PTR	EnergyOrb only	Opt in	2008	Summer	23%	1%
Smart Energy Pricing Pilot	PTR low	PTR	EnergyOrb, AC switch	Opt in	2008	Summer	28%	1%
Smart Energy Pricing Pilot	PTR high	PTR	None	Opt in	2008	Summer	21%	1%
Smart Energy Pricing Pilot	PTR high	PTR	EnergyOrb only	Opt in	2008	Summer	27%	1%
Smart Energy Pricing Pilot	PTR high	PTR	EnergyOrb, AC switch	Opt in	2008	Summer	33%	1%
SmartPricing Options	Opt-in TOU, IHD offer	TOU	IHD	Opt in	2012	Summer	13%	1%
SmartPricing Options	Opt-in TOU, no IHD offer	TOU	None	Opt in	2012	Summer	10%	1%
SmartPricing Options	Opt-in CPP, IHD offer	CPP	IHD	Opt in	2012	Summer	26%	4%
SmartPricing Options	Opt-in CPP, no IHD offer	CPP	None	Opt in	2012	Summer	22%	–1%
SmartPricing Options	Default TOU, IHD offer	TOU	IHD	Default	2012	Summer	6%	1%
SmartPricing Options	Default CPP, IHD offer	CPP	IHD	Default	2012	Summer	12%	3%
SmartPricing Options	Default TOU-CPP, IHD offer	TOU CPP	None	Default	2012	Summer	8%	1%
SmartPricing Options	Opt-in TOU, IHD offer	TOU	IHD	Opt in	2013	Summer	11%	1%
SmartPricing Options	Opt-in TOU, no IHD offer	TOU	None	Opt in	2013	Summer	9%	1%
SmartPricing Options	Opt-in CPP, IHD offer	CPP	IHD	Opt in	2013	Summer	24%	4%
SmartPricing Options	Opt-in CPP, no IHD offer	CPP	None	Opt in	2013	Summer	21%	–1%
SmartPricing Options	Default TOU, IHD offer	TOU	IHD	Default	2013	Summer	6%	1%
SmartPricing Options	Default CPP, IHD offer	CPP	IHD	Default	2013	Summer	17%	3%
SmartPricing Options	Default TOU-CPP, IHD offer	TOU CPP	None	Default	2013	Summer	10%	1%
Ontario Smart Price Pilot	TOU	TOU	None	Opt in	2006	Fall/winter	6%	6%
Ontario Smart Price Pilot	TOU+CPP	TOU CPP	None	Opt in	2006	Fall/winter	25%	5%
Ontario Smart Price Pilot	TOU+PTR	TOU PTR	None	Opt in	2006	Fall/winter	18%	7%
EnergySense CPP Pilot	CPP	CPP	Web portal	Opt in	2011	Summer	37%	0%

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
EnergySense CPP Pilot	CPP	CPP	Web portal	Opt in	2012	Summer	23%	0%

Appendix D. Measure and Program Description

Table D1. Measure and program descriptions

Measure or program	Applicability	Description
LED 40-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
LED 60-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
LED 75-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
Variable-speed pool pump	Replace on burnout and new construction	Variable-speed pumps enable pool technicians to set a pool pump exactly to the lowest motor speed requirements for both the daily cleaning and daily filtration settings, thus saving wasted energy.
Duct test and repair	Retrofit	The Duct Test and Repair measure consists of testing the ducts for leakage and repairing them as needed. Duct testing includes determining the amount of air leakage, identifying leakage locations, making sure the duct connections are securely fastened, and providing test results to the homeowner. Duct repair includes repairing ductwork, sealing duct connections with long lasting sealant, and repairing any unsealed or poorly fitting grills. The ducts are then retested after the repairs and sealing are completed to verify leakage reduction.
Prescriptive duct repair	Retrofit	Duct repair includes repairing ductwork, sealing duct connections with long lasting sealant, and repairing any unsealed or poorly fitting grills. The ducts are then retested after the repairs and sealing are completed to verify leakage reduction.
Advanced diagnostic tune-up	Retrofit	The Advanced Diagnostic Tune-Up measure is a refrigerant charge and airflow correction for residential air conditioners and heat pumps that are at least three years old and between two and five tons.
Equipment replacement with quality installation	Replace on burnout	The Equipment Replacement with Quality Installation measure gives an incentive for customers to use a participating contractor to replace an air conditioner or heat pump that is at least 10 years old with a new system that is installed in accordance with Arizona Public Service Quality Installation Standards.

Measure or program	Applicability	Description
Res new construction ESTAR Homes v3.0	New construction	This whole house option promotes ENERGY STAR certified new homes designed and built to standards well above most other new homes. An ENERGY STAR certified home has undergone a process of inspections, testing, and verification to meet strict EPA requirements, delivering better quality, better comfort, and better durability.
Res new construction ESTAR Homes v3.0 - Tier 2	New construction	This is the same as 3.0, but with improved efficiency for building envelope, windows, and HVAC, and a better Home Energy Rating System (HERS) rating.
Res new construction total program	New construction	This whole house option promotes ENERGY STAR certified new homes designed and built to standards well above most other new homes. An ENERGY STAR certified home has undergone a process of inspections, testing, and verification to meet strict EPA requirements, delivering better quality, better comfort, and better durability.
Attic insulation	This measure is applicable only to the Home Performance with ENERGY STAR program.	Attic insulation involves repairing and/or adding insulation to existing attics. Insulation must be installed in the right location and without gaps, voids, or compressions. Homes must be properly air sealed prior to increasing attic insulation to achieve maximum performance. Insulation values are based on the measure of a material's thermal resistance, or *R-value*.
Air sealing and attic insulation	This measure is applicable only to the Home Performance with ENERGY STAR program.	This measure includes installation of a combination of air sealing and attic insulation for a single participant home. Air sealing is performed prior to attic insulation for maximum performance.
Smart strip	Retrofit	This measure is for load-based smart strips. The measure should be installed only in the primary entertainment center and primary home office.

Source: APS 2016

Appendix E. Payback Analysis Scenario Detail

Table E1. Payback analysis scenario details

Scenario	Customer charge	Energy tiers	Description	Demand charge ($/kW)	Summer off-peak ($/kWh	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)	No. of times coincident peak hit
1	$5	Yes	Low customer charge, three-tiered rate (0–500, 501–1,000, >1,000)	$-	$0.1504				
2	$25	Yes	High customer charge, three-tiered rate (0–500, 501–1,000, >1,000)	$-	$0.1101				
3	$5	No	Low customer charge, flat energy rate	$-	$0.1076				
4	$25	No	High customer charge, flat energy rate	$-	$0.0824				
5	$50	No	Very high customer charge, flat energy rate	$-	$0.0510				
6	$5	No	Low customer charge, 4:1 ratio TOU	$-	$0.0904	$0.1809	$0.0907	$0.1815	
7	$25	No	High customer charge, 4:1 ratio TOU	$-	$0.0727	$0.1454	$0.0645	$0.1291	
8	$5	No	Low customer charge, 3:1 ratio TOU	$-	$0.0773	$0.2320	$0.0795	$0.2384	
9	$25	No	High customer charge, 3:1 ratio TOU	$-	$0.0622	$0.1865	$0.0570	$0.1696	
10	$5	No	Low customer charge, 2:1 ratio TOU	$-	$0.0676	$0.2702	$0.0707	$0.2828	
11	$25	No	High customer charge, 2:1 ratio TOU	$-	$0.0543	$0.2171	$0.0503	$0.2011	
12	$5	No	Low customer charge, flat mid-demand charge	$5.00	$0.0815				6

Scenario	Customer charge	Energy tiers	Description	Demand charge ($/kW)	Summer off-peak ($/kWh	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)	No. of times coincident peak hit
13	$15	No	Mid customer charge, flat mid-demand charge	$5.00	$0.0690				6
14	$25	No	High customer charge, flat mid-demand charge	$5.00	$0.0564				6
15	$5	No	Low customer charge, flat high-demand charge	$7.50	$0.0685				6
16	$15	No	Mid customer charge, flat high-demand charge	$7.50	$0.0559				6
17	$25	No	High customer charge, flat high-demand charge	$7.50	$0.0434				6
18	$5	No	Low customer charge, tiered demand charge	$10.00	$0.0555				6
19	$15	No	Mid customer charge, tiered demand charge	$10.00	$0.0429				6
20	$25	No	High customer charge, tiered demand charge	$10.00	$0.0303				6

Appendix C

Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers

Paul Chernick, John T. Colgan, Rick Gilliam, Douglas Jester, and Mark LeBel, 2016.

Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

July 18, 2016

Paul Chernick
John T. Colgan
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Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

Introduction & Overview

There has been significant recent attention to the possibility of including demand charges in the electricity rates charged to residents and small businesses. Electric utilities have historically served these 'small customers' under a two-part rate structure comprised of a fixed monthly customer charge that recovers the cost of connecting to the grid and an energy charge (or charges) that recover all other costs. Much of this attention to the issue of demand charges for small customers has been initiated by electric utilities reacting to actual or potential reductions in sales, revenue and cost recovery.

Demand charges are widely familiar to large, commercial and industrial customers, where they are used to base some portion of these customers' bills on their maximum rate of consumption. While a customer charge imposes the same monthly cost for every customer in a rate class, and an energy charge usually imposes the same cost per unit of energy used over a long period of time (e.g. the entire year, a month, or all weekday summer afternoons), most demand charges impose a cost based on usage in a very short period of time, such as 15 minutes or one hour per month. The timing of the specific single maximum demand event in a month that will result in demand charges is generally not known in advance.

The goal of this document is to unpack the key elements of demand charges and explore their effect on fairness, efficiency, customer acceptability and the certainty of utility cost recovery. As will be evident, most applications of demand charges for small customers perform poorly in all categories. Following are five key takeaways:

- Residents and small businesses are very diverse in their use of electricity across the day, month and year — most small consumers' individual peak usage does not actually occur during peak system usage overall. This means that traditional demand charges tend to overcharge the individual small consumer.
- Apartment residents are particularly disadvantaged by demand charges because a particular apartment resident's peak usage isn't actually served by the utility. Utilities only serve the combined diverse demand of multiple apartments in a building or complex rather than the individual apartment unit.
- Demand charges are complex, difficult for small consumers to understand, and not likely to be widely accepted by the small customer groups.
- Very little of utility capacity costs are associated with the demands of individual small consumers. Nearly all capacity is sized to the combined and diverse demand of the entire system, the costs of which are not captured by traditional demand charges. If consumers actually were able to respond to a demand charge by levelizing their electricity usage across broader peak periods, then utilities would incur revenue shortages without any corresponding reduction in system costs.
- Demand charges do not offer actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This results in effectively adding another mandatory fixed fee to residential and small consumer electric bills.

About the Authors

Paul Chernick, President, Resource Insight, Massachusetts. With nearly 40 years of experience in utility planning and regulation, Mr. Chernick has testified in about 300 regulatory and judicial proceedings.

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The authors thank the many colleagues from organizations around the country who offered their technical, legal and policy insights and perspectives on this paper.

Legacy Demand Charges

While there are a large number of variants on the basic theme, the standard demand charge is a fee in dollars per kW times the customer's highest usage in a short (e.g. one-hour) period during the billing month. These charges are nearly universal for industrial and larger commercial customers.

This rate design is a legacy of the 19th century, when utilities imposed demand charges to differentiate between customers with fairly stable loads over the month (mostly industrial loads) from those who used lots of energy in a few hours, but much less the rest of the month. Utilities recognized that the latter customers with peaky loads were more expensive to serve per kWh, and monthly maximum demand was the only other measurement available given existing meter technology at the time.

Beyond the standard design, variants include:

- Billing demand computed as the highest load over 15 or 30 minutes, rather than an hour;
- Charges per kVA rather than per kW, thereby incorporating power factor;
- Charges that are higher in some months and/or some daily periods than in others;
- Ratchets, in which the demand charge can be set by the highest load in the preceding year or peak season, as well as the current month; and
- Hours-use or load-factor rates, where the price per kWh declines as monthly kWh/kW increases, thereby incorporating an effective demand charge within an energy charge framework. For example:

First 200 kWh/kW	$0.15
Next 200 kWh/kW	$0.12
Over 400 kWh/kW	$0.10

For a high load factor customer (e.g. over 400 kWh/kW, or 60%), this works out to a $14/kW demand charge. But, for a low load factor customer with high peak demand at some times but otherwise low usage, like a school stadium lighting system with only 20 hours/month of usage, this rate design example works out to $1/kW (20 hours x .05/kWh built into the first 200 kWh/kW).

Demand-Charge Design Elements

As noted above, the standard demand charge uses the billing demand at the time of the customer's greatest consumption, integrated over a short period such as one hour, measured monthly. Thus, the charge is based on a single hour out of the 720 hours of a 30-day month, with each customer charged for load in whichever hour their maximum demand occurs, regardless of coincidence with the peak demand of the system. Because a customer's individual peak demand can occur at any time of day and not necessarily during the hour when system costs are greatest, the standard demand charge does not generally reflect cost causation. There are three categories of design options for demand charges: the time at which demand is measured, the period over which demand is averaged, and the frequency of its measurement.

Timing of billing demand measurement

The term "peak demand" is used in many different ways in utility jargon. These peaks include the following:

- **Customer peak:** Each customer experiences a non-coincident[1] maximum demand (NCP) at some point in the month. That value is typically used in legacy demand charges. Each customer also experiences a maximum non-coincident demand for the year (i.e. the highest of 12 monthly maximum non-coincident demands). This value is used for demand charges with ratchets.[2]
- **Equipment peak:** Each piece of utility transmission and distribution equipment experiences a maximum load each month and each year. Utilities often have detailed data on the timing of loads on substations, transmission lines, and distribution feeders. They use those data for system planning, but usually not in setting rates. The capacity of equipment varies with weather; when temperatures are cooler, equipment dissipates heat better and has more capacity.
- **Class peak:** Utilities generally estimate a class peak load for each customer class (e.g. residential, small commercial, large commercial), which may occur at different hours, months and seasons. Aggregated class peaks are often used in allocating some distribution costs to classes.
- **System peak:** The entire system experiences a maximum peak in each month, one of which will be the annual maximum peak. Loads of customers or customer classes measured at the time of the maximum monthly or annual system peak are said to be coincident demands for that month or year.
- **Designated or seasonal peak:** Utilities often designate a "peak period" for one or more months, when there is a high probability that the system's highest peak demands will occur, such as 3-7 p.m. from June through September. However, these designated peak times are based on expectations and do not necessarily coincide with actual system peak. Demand charges may measure each customer's highest one-hour demand during these periods. This is sometimes incorrectly referred to as a 'coincident peak demand charge,' or a 'demand time of use rate.'

Because of their diversity in energy usage, customers' individual non-coincident maximum loads usually do not occur at the same time as the peaks on the system as a whole — or even at the same time as peaks on the local distribution system. Thus, in addition to not reflecting the customer's contribution to utility costs, billing on the customer maximum demand does not effectively encourage customers to reduce their contribution to costs, and may actually encourage customers to move load from the times of their individual maximum demands to times of high system loads and costs. Unlike attempting to capture customer coincident demands, billing parameters for customer non-coincident load is relatively easy to measure. However, these loads are difficult to control, and a single brief unusual event (e.g. simultaneous operation of multiple end uses or equipment failure) can set the billing demand for the month and year.

With modern utility metering, utilities have the option of charging for customer loads at times that more closely correspond to cost causation — times when the system (or its various parts) is experiencing its maximum demand. A range of approaches are available:

- **Actual coincident peaks**. Because many cost allocation systems assign at least a portion of generation and transmission costs to customer classes on the basis of customer class contributions to the system peak(s) — the coincident peak or "CP" method — there is some logic behind billing on the basis of the individual customer's contribution to the system peak. A significant challenge with CP billing is there is no way to know that a particular hour will be the system peak, even as it is occurring, since a higher load may occur later in the day, month, season or year. The utility could provide customers with information on current and forecast loads, and each customer could try to respond to the *possibility* of a system peak, spreading out their response across many high load hours,

[1] The term "non-coincident" means not *intentionally* coincident with, i.e. at the same time as, the system peak. Coincidence with the system peak would only be by happenstance.
[2] The sum over customers by class of maximum non-coincident annual peak demands is used by some utilities in allocating some distribution costs.

only one of which will actually be used in computing billing demand. Like Russian Roulette, it is likely to be difficult for many residential and small commercial customers to understand and respond to this type of system.

- **Designated peak hours**. Rather than computing the billing demand for the actual system peak hours, the utility could, on relatively short notice, designate particular hours as potential peak (or potentially critical) hours and compute the billing demand as the average of the customer's load in those hours. This approach is similar to the designation of critical peak periods in some time-of-use rates or peak-time rebates in some load-management programs. Provided that the potential peak hour information can be effectively communicated to all customers subject to the structure, the ability to respond should be somewhat improved over the NCP and CP approaches.
- **Forecast peak periods**. Rather than designating individual hours for computation of billing demand, a utility could designate a peak window, such as noon to 4 p.m., when the system is likely to experience a peak or other critical condition, and set the billing demand as the customer's average consumption during that window. The hours around the system peak hour also tend to experience loads close to the actual peak load and contribute to reliability risk. Shifting load from the peak hour to one hour earlier or later may create a worse situation in that new hour. Here too, customers may be better able to respond to forecast peak periods than to individual hours, even if the period is only designated the day before or a few hours before the event.
- **Standard peak-exposure periods**. In the above examples, customers may only learn about peak periods after-the-fact or just a day or hours before they are set, but utilities could set time periods farther in advance, for instance in a rate case as part of the tariff itself. Especially for small customers, establishing a fixed period in which peaks and resource insufficiency are most likely, such as July and August weekdays or even more narrowly non-holiday summer weekday periods between noon and 4 p.m., may be more acceptable and effective than declaring the demand-charge hours on short notice. This approach trades improved predictability for customers for a diminished relationship to system costs. Customer response, such as limiting their maximum energy demands during the known peak periods, would be similar to the response to time of use rates, but with the consequences of not responding potentially more dire.

Period of billing demand measurement

Measurement of the customer's billing demand can occur over a wide variety of time frames. An instantaneous or short-duration measure of billing demand is possible but would penalize customers with overlapping loads of standard behind the meter technologies. Many residential customers have limited choice or control over when they use appliances. For example, electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively. Air conditioners draw from 2 kW for a one-ton capacity model to 9 kW for a five-ton model. In addition, common hair dryers typically draw 1 kW and often more; the average microwave or toaster oven can draw 1 kW; and an electric kettle can draw 1 kW.

It is easy to see how the typical morning routine for a family would result in an instantaneous peak demand of as much as 18 kW and demand over a one-hour period in excess of 10 kW. A billed demand of 10 kW or more would result in high and hard-to-avoid charges, in addition to a fixed monthly charge, meaning that this household would have little to no control over the bulk of its monthly bill.

While families may be able to understand how this peak demand occurs, school schedules and work schedules may allow little flexibility to do anything about it. Further, many of these devices are designed to be automatically controlled by thermostats that would be difficult to override on a short-term basis to avoid demand charges. Moreover, these overlapping appliance demands do not drive costs on the system.

This example shows the electric demand of a morning schedule, while peak system demands are often later in the day. In addition, customer diversity can spread these demands out, diluting any effect on peak system demand.

At the other extreme, the billing demand measure could be 720 hours, for a 30-day month. This billing period would capture all the loads imposed by the customer to the utility system and requires no new metering. In fact, this billing approach is in common practice today and is known as the two-part rate, which charges customers for demand during each hour of each day of the billing period (a.k.a. energy) on top of the basic flat monthly customer charge.

Within this spectrum, the most common billing demand periods in practice today for commercial and industrial customers (outside of the two-part rate) range from 15 minutes to 60 minutes.[3] Short periods of measured billing demand are more difficult for customers to manage. For example, an apartment dweller who takes a shower and dries their hair while something is in the oven can run up demand of 10 kW or more, even though the average contribution to the system peak across units in the same apartment building is typically no more than 2 or 3 kW. Longer periods of measurement, such as 60 minutes or the average demand over several hours, tend to dilute the impacts of very short-term events.

There is great diversity in maximum loads among residential consumers. As mentioned above, demand charges have historically only been applied to large commercial and industrial customers, with a multitude of loads served through a single meter, and generally a dedicated transformer or transformer bank. For very large industrial customers, there is typically a dedicated distribution circuit or even distribution substation. So for these customers, diversity occurs on the customer's side of the meter, such as when copiers, fans, compressors, and other equipment cycles on and off in a large office building.

For residential consumers, there is also diversity — but it occurs on the utility's side of the meter as customers in different homes and apartments connected to the same transformers and circuits use power at different moments in time. The point is that the type of rate design that is appropriate for industrial customers, who may have a dedicated substation or circuit, is not necessarily appropriate for residential customers who share distribution components down to and including the final line transformer.

Indeed, in the example in the previous section regarding measurement of peak demand during a window designed to capture higher-cost hours (i.e. standard peak-exposure periods), one can envision a peak demand period that covers the entire window. Such an approach may be more closely tied to cost causation, but it would be difficult for the customer to respond unless measurement occurred each day and was averaged for the full billing period.

Frequency of billing demand measurement

By far the most common frequency of measurement is once per month. However, this is not the result of careful study and analysis, but is rather a matter of convenience related to the selection of billing periods approximating one month. Months and billing periods are arbitrary creations, whereas cost variation tends to be more seasonal in nature at the macro-scale, weekly at a mid-scale (workdays vs. weekends and holidays), and daily at a micro-scale.

However, actual generation capacity requirements are driven by many high-load hours, which collectively account for most of the risk of insufficient capacity following a major generation or transmission outage,

[3] A related decision point is specifying whether the billing demand period to be measured is random or clock-based. For example, can a 60-minute billing demand period begin at any time, or should it be restricted to clock hours?

so any single peak customer load is unlikely to provide optimal price signals. Pragmatically, loads of very short duration — the highest 50 hours per year or so — are best served with demand response measures that require no investment whatsoever in generation, transmission, or distribution capacity.

Some commercial and industrial customers are subject to what are called "demand ratchets" which set the minimum billing demand for each month based on a percentage (typically 50% to 100%) of the maximum billing demand for any month in the previous peak season (summer or winter) or previous 11 or 12 months. While ratchets smooth revenue recovery for the utility, they are the antithesis of cost causation in a utility system with diversified loads, and can severely penalize seasonal loads. The resulting unavoidable fixed charges impair the energy conservation price signal to customers. Therefore, billing demands could reflect cost causation more closely by having seasonal elements, and also weekly and daily elements, but this increases the complexity. Alternatively, demands could be measured and averaged over the 100 hours each month that contribute most to system peak loads.[4]

Finally, as discussed relative to the period of measurement, if kW of demand were to be measured in every hour of the month and summed, the result would be the current two part rate with no additional more expensive metering required.

Evaluation of Demand Charges

Loads, load management and load diversity

The costs that utilities typically recover in existing demand charges applied to large customers include those that are usually assigned to customer classes on the basis of a demand allocator.[5] These costs tend to be fixed for a period of more than one year, and usually include one or more of the following:

- Generation capacity costs (cost of peaking generators and all or a portion of the cost of baseload[6] units)
- Transmission costs (all or a portion)
- Distribution costs (all or a portion of distribution circuits and transformer costs)

Some utilities utilize separate demand charges for each major function, or sometimes group functions together, such as generation and transmission, that are allocated to customer classes on similar bases.

Because billing demand is a function of the total load of a customer's on-site electrical equipment operating simultaneously for a relatively short period of time, the demand charge may act as an incentive to levelize demand across the day. The types of large commercial and industrial customers that are currently subject to demand charges are usually sophisticated enough to understand the sources and timing of their electrical equipment and its consequent energy consumption.[7] Many, i.e. over half,[8] have

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[4] Such a system would be more likely to capture high loads and peak demands on the system sub-functions, e.g. transformers, feeders, substations, transmission, and generation.
[5] It should be noted that some jurisdictions allocate a portion of fixed costs on average demand, or energy.
[6] Because baseload units serve all hours, many regulators have used the Peak Credit or Equivalent Peaker method to classify baseload plant costs between Demand and Energy. For example, in Washington, it's about 25% demand, 75% energy. In marginal cost studies, only the cost of a peaker is typically considered demand-related.
[7] Most utilities do not apply demand charges to small commercial customers under 20-50 kW demand.

energy managers whose job in part is to manage that energy consumption in light of the rates and rate structure of their local utility. Monitoring and load management equipment can be employed to maximize profitable industrial processes while avoiding new, higher peak demand charges. In other words, sophisticated large commercial and industrial customers may use energy management systems to restrain demand by scheduling or controlling when different pieces of equipment are used like fans, compressors, electrolytic processes, and other major equipment, in order to levelize the load over the day. Because these large customers have a diversity of uses on their premises, they may be able to manage that diversity to present a relatively stable load to the utility.[9] However, because individual customer demand often does not coincide with system demand, much of the demand management activity by the more sophisticated large customers is essentially pointless and wasteful from a system cost perspective.

Moreover, while it appears utilities believe demand-charge revenues are more stable than energy revenues, the stability of demand charge revenue even for large customers is highly dependent on the size, load factor and weather sensitivity of the large customers.

The sophistication of large customer energy management does not currently exist for most small commercial and residential customers. These customers have a great deal of load diversity, but that diversity is not within a single customer but between different customers using power at different times (see Appendix B). In these classes, because each customer is served through a separate meter, it is unlikely that individual constituents will have much ability to reduce the overall system demand or their own maximum billing demand in any significant way without acquisition and effective use of advanced load monitoring and management technologies. Residential demand controllers are marketed to all-electric customers (e.g. at some rural utilities with limited circuit capacity) that have implemented demand charges. These do enable customers with electric cooking, water heating, clothes dryers, space conditioning, and swimming pools to levelize their demand. But for urban apartment dwellers and other low-usage customers, the natural diversity between customers is much greater than the potential control over the diversity of uses within a household.

Technologies to manage and control this diversity of small customer usage are best deployed as demand response measures, targeted at hours that are key to the system, not to the individual consumer usage pattern. As a result of the small customers' lack of ability to control individual peak demands, a demand charge on small customers acts effectively as a fixed charge and generally provides a more stable and consistent revenue collection vehicle for the utility than volumetric energy charges.

Cost drivers and load alignment

Evidence shows that small residential customers are less likely to have their individual high usage occur at the time of the system peak demand, whereas large residential users are more likely. This is simply because large residential users are more likely to have significant air conditioning and other peak-oriented loads. Large residential users' loads tend to be more coincident with system peak periods and thus more expensive to serve. As a result of these load patterns, on an individual customer basis large residential users have higher individual load factors, meaning they will pay lower average rates if a non-coincident demand charge is imposed.

The figure below shows this relationship, in the context of residential customers:

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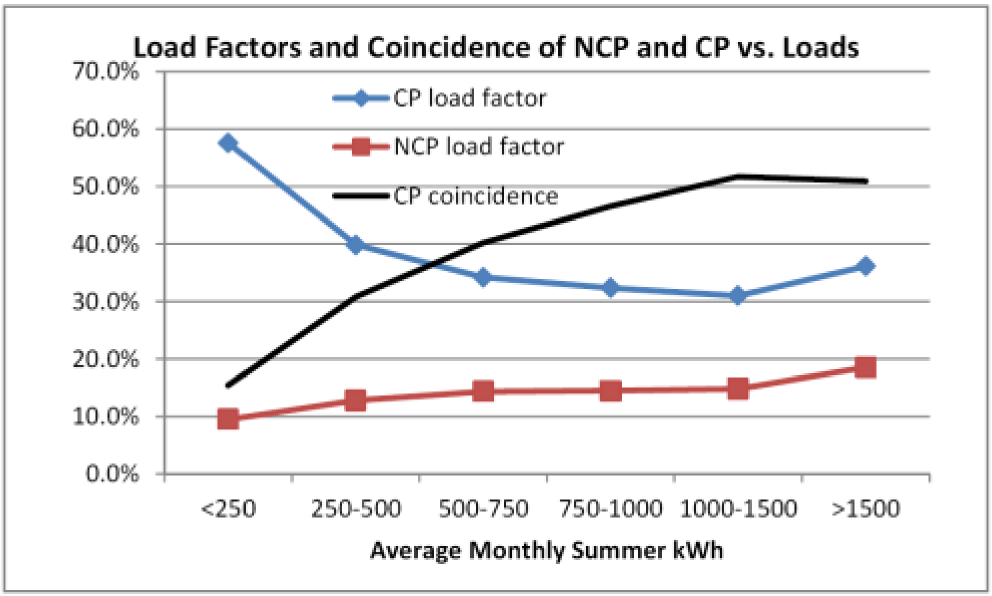
[8] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, p. 76, May 2016 download at: www.rmi.org/alternative_rate_designs

[9] That stable load may not be less expensive to serve than the customer's most efficient load.

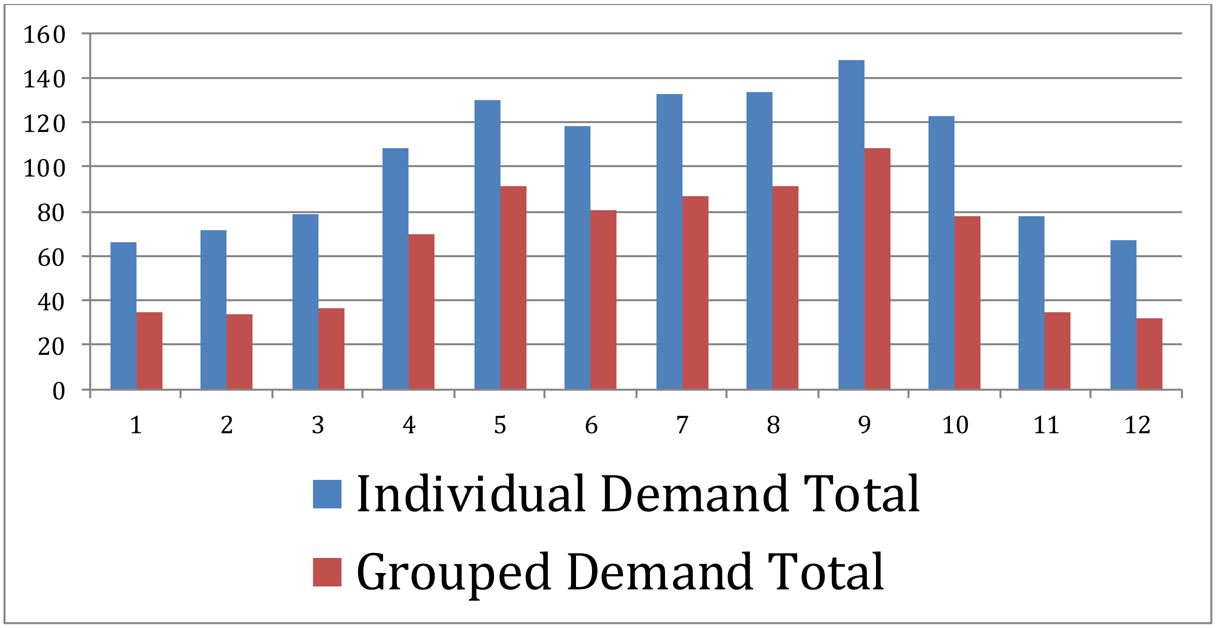


Source: Marcus Presentation to WCPSC, June 2015

The black line shows customers whose individual peak demand coincides with system peak tend to have both higher monthly energy use (kWh) and higher metered individual load factors. The red line shows that larger-use customers have higher individual metered non-coincident load factors. The blue line shows that smaller-use customers have higher "group" collective load factors, measured relative to the system coincident peak.

As described above, the breadth of equipment on a large commercial or industrial customer's site results in load diversity behind the meter allowing for a fairly smooth load pattern for these larger customers. Smaller customers without the same degree of behind the meter load diversity have many small appliances that often operate for short periods of time. It takes but a few operating simultaneously to establish a peak demand. For a large group of 100,000 to one million customers or so, there is a general pattern for the class load and in many cases it tends to drive the utility's peak demand towards later in the day, but on an individual customer basis, peak loads can occur at any time during the month depending on the lifestyle, ages of family members, work situation, and other factors.

Apartments are particularly affected. About three-quarters of apartments in the US have electric water heaters. An electric water heater draws 4.4 kW when charging, but only operates about two hours per day, for a total of about 9 kWh of consumption per day. But each apartment has its own water-heating unit. Combined with hair dryer, range, clothes dryer, and other appliances, an apartment unit may draw 10-15 kW for short periods, but only about 0.5 to 1.0 kW on average (360-720 kWh per apartment per month). Because many apartments are served through a single transformer and meter bank, what actually matters to system design is not the individual demands of apartments, but the combined (diverse) demand of the building or complex. The illustration below shows how the sum of individual apartments' maximum hourly demands in one apartment building (in the Los Angeles area) compares to the combined maximum hourly demand for the complex:



Source: RAP Demand Charge Webinar, December 2015

The equity of rates and bills for apartment residents, where each household has few residents, but the entire building is connected to the utility through a single transformer bank, must also be addressed because the utility does not actually serve the consumption of individual customers, but only their collective needs. Finally, if customers do respond and levelize their consumption across the day or across the peak hours to minimize their demand charges, then the rates designed will not produce the revenue expected but any impacts on system costs (e.g. avoided upgrades or expansions) would likely not occur for years.

Appendix B contains residential load curves for customers in New Mexico and Colorado covering the four summer peak days for the utility providing service. It is clear from these charts that individual residential customer load is volatile, and not subject to consistent patterns that the customer would be in a position to manage. Each customer experienced its individual peak at a unique time. The collective group peak was not at the time of each individual customer's peak in any of the months. The bottom line is no discernible cost causation relationship with individual customers' peak demand.

Metering costs and allocation

Finally, demand charges also require more complex, and expensive, metering technologies than conventional two-part tariffs. The cost-effectiveness of these upgrades should be analyzed on their own merits, and where the costs are justified by energy savings or peak load reduction, they should be treated in the same fashion as the costs that are avoided, with only the portion justified by customer-related benefits (e.g. reduced meter reading expense) treated as customer-related. The remainder would be attributed to such drivers as energy costs and coincident peaks. For more information, see Smart Rate Design for a Smart Future for a discussion of how Smart Grid costs should be classified and allocated in the rate design process.[10]

[10] Regulatory Assistance Project, Smart Rate Design for a Smart Future, 2015.

Demand charges as a price signal

Imposition of demand charges runs counter to the ratemaking principles of simplicity, understandability, public acceptability, and feasibility of application. It's a formidable task to try to train millions of customers in the meaning of billing demand, the factors driving it, and how to control and manage it. Indeed, RMI (2016, p. 76) notes "[w]hile it's possible that, if customers are sufficiently educated about a demand charge rate, they will reduce peak demand in response, no reliable studies have evaluated the potential for peak reduction as a result of demand charges." The same RMI report indicates that time-varying energy charges are more effective at reducing peak demands than are demand charges.[11] Additionally, the Brattle Group reported a peak load reduction of less than **2%** for residential demand charges, compared with reductions as great as **40%** for critical peak pricing energy rates.[12]

The examples given in Appendix B show no pattern that a customer might be able to manage in advance — which is the knowledge required in order to control a peak demand occurrence. In part this is due to a mix of appliances that are set to turn on and off automatically as needed (e.g. air conditioning, hot water heaters, refrigerator) and others that are under the control of the home or small business owner (e.g. lighting, hair dryers, kitchen appliances, television). Without sophisticated load control and automation devices, it is unclear how small customers could manage peak loads. Without installation of such load control technology, a demand charge is not an effective price signal. Importantly, a charge like a demand charge is only a price signal if the customer can respond to it. If not, it becomes an unmanageable fixed charge with a substantially random character.

Indeed, large residential customers with many appliances (e.g. swimming pool heaters and pumps) that have higher load factors may benefit from demand charges as cost recovery is shifted to a charge based on a single peak demand from demand-related costs being applied against every kWh. This has been true with the larger commercial and industrial class as well. Conversely, low usage customers — including low-income customers — would likely pay more on average.

The Bonbright Criteria

Professor Bonbright's famous 1961 work, Principles of Public Utility Rates, outlined eight criteria of a sound rate structure. It is useful to consider how demand charges fare under these criteria and the following summary addresses each criteria.

1. **The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.**

   Simplicity: While the demand rate itself can be viewed as simple — a single charge applied to a single parameter — the concept of demand integrated over a short time frame (e.g. 15 minutes or one hour) is not simple and requires customer education.

   Understandability: The application and management of demand rates is likely to be difficult because customers cannot easily manage the demand in the short time intervals typically applied to demand charge rate design.

[11] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, May 2016 download at: www.rmi.org/alternative_rate_designs
[12] Presentations of Ahmad Faruqui and Ryan Hledik, EUCI Residential Demand Charge Summit, 2015.

Public acceptability: Demand charges are not likely to be readily accepted by small customers for the reasons outlined above. Indeed, for most consumers they will just seem like another fixed charge. (See Arizona Public Service Company case study below.)

Feasibility of application: While technically feasible, new metering is required. The likely metering technology is smart meters that can also be used for more appropriate time-varying rates (although some claim the smart meter only estimates the peak demand). As noted above, it is not clear that customers can respond to demand charges; for many utilities, the attraction of demand charges for small customers may be that customers will not be able to avoid them.

2. Freedom from controversies as to proper interpretation.

Proper interpretation of demand charges will be difficult for customers who don't have the behavioral or technological ability to understand, prepare for and manage peak demands in advance. This may result in misunderstandings, frustration and increasing complaints. A utility should be able to demonstrate that the smallest customers currently on demand rates understand their bills, before applying demand charges to still smaller customers.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

Rate structures that establish an effective relationship between billing parameters and cost causation are reasonably likely to yield total revenue requirements following implementation. However, it is clear that individual maximum demands for small customers are very diverse and rarely occur at the time of maximum system demand. To the extent small customers are able to respond to the demand price signal, they may move their peak load from a less costly time of day to a more costly time of day, and their measured demand (and the associated revenue) may vary sharply from month to month as different appliances happen to be used simultaneously generating the measured demand upon which the charge is based. Thus the link with cost causation is weak, and achieving total revenue requirements is more at risk.

4. Revenue stability from year to year.

Similarly, the weak cost causation link can cause instability as a significant portion (often 60% or more) of a small customer's revenue is dependent on the relative stability of a single 15 minute or one hour period during the entire month. Customer peak demand, particularly for air conditioning customers, is highly temperature sensitive, so mild summers may result in severe undercollection of revenues.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

Here, too, it is unclear whether demand charges for small customers will be stable over time, but given the volatility of small customer loads, bills may lack stability. If small customers are unable to respond to the demand charge price signal, then the demand charge will act as a fixed charge and the *rate* would likely be stable. If over time small customers are able to use technologies or behavioral changes to reduce maximum demands, utility revenue may drop significantly and the rate will need to be increased to recover allowed revenues, and thus will be less stable. This paradoxical situation results in the shifting of costs from those able to manage peak loads to those who are unable.

6. Fairness of the specific rates in the apportionment of total costs of service among the different customers.

As pointed out above in comparing customers of different sizes (see for example the apartment dwellers discussion), small customers tend to have lower individual load factors, i.e. higher peak demands relative to their energy consumption, but higher collective group load factors (which drive utility capacity needs). In fact, lower use customers tend to have less coincidence of their individual peak demands with the system peak demand. As a result, demand charges paid by these customers would be associated with a time period that is not correlated with cost causation. This would place an unfair burden on small customers.

7. **Avoidance of "undue discrimination" in rate relationships.**

   As above, the lower coincidence of individual peak demands of lower use customers with system peak loads should lead to lower charges or bills, but applying the same demand charges to the customer's peak demand whenever it occurs would generate high charges and bills, thus discriminating against low use customers.

8. **Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:**

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

As noted in the body of this paper, in addition to a lack of coincidence with cost-causing system peak loads, demand charges (particularly NCP demand charges) are generally not actionable for small customers. Thus the small customer cannot respond to this "signal" in any meaningful way that might result in lower utility costs.

More importantly, there is evidence that small customers can and do respond to price signals based on energy charges that vary by time or usage. Shifting cost recovery from energy charges to demand charges reduces the customer's incentive to reduce consumption, and results in an inefficient use of resources.

Finally, the authors of this paper support the concept of **customer agency.** In other words, the customer should have choice, control, and the right of energy self-determination. Demand charges without associated technology to control demand tend to act as fixed and unavoidable charges, and will have the effect of reducing the variable energy rate. These rate changes can significantly diminish the incentive for customers to reduce energy consumption through behavioral changes, energy efficiency technologies, or distributed generation resources and result in increased fossil fuel emissions.

Arizona Case Study

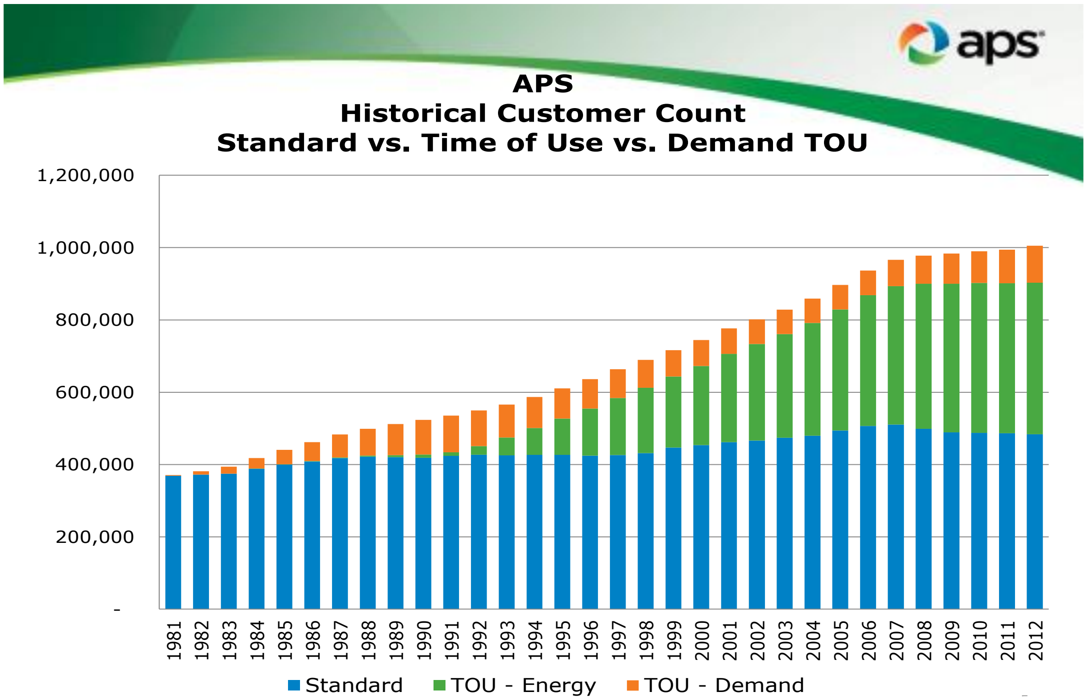
While no regulatory Commission has approved mandatory demand charges for residential customers in recent memory, this has not always been the case. A real world example is Arizona Public Service Company's (APS) residential demand rate. APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has about 10% enrollment. The customers who self-select onto this rate design are those whose usage patterns benefit from this rate option; others choose a TOU rate or an inclining block rate. The Company assists customers in identifying the lowest cost rate option for their individual usage patterns.

In a 2015 case study performed by APS, the utility explains that its optional residential demand rate "helps customers select the best rate at time of new service through [its] website rate comparison tool."[13] An examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption nearly three times the average monthly consumption of customers on the default rate.[14]

There is important history here. In the late 1980's, as the Palo Verde nuclear plants came into service and APS rates increased sharply, the ACC implemented inclining block default rates. The company opposed this at the time, but found a work-around for large-use customers, the demand and TOU rates. The demand and TOU rates have no inclining blocks (there are no barriers to implementing both together, but Arizona has not done so), so it is a way for large-use customers to avoid the higher per-unit price for higher unit that the Arizona Corporation Commission (ACC) created in with the inclining block rate design. The Company markets the demand rate only to large-use customers who they think will benefit. Many of these customers have diverse loads behind the meter, and can benefit from a demand charge if they have (or can shape) load to take advantage of the rate design, and evade the inclining block rate. Some install demand controllers to ensure their water heaters or swimming pool pumps turn off when the air conditioning turns on.[15] So it is a self-selected subclass of customers with above-average usage, and above-average diversity. Results from this subset should not be presumed to reflect behavior or experience of other subclasses.

Use of the rate comparison tool for self-selection infers that those APS residential customers who have chosen to take service on the demand rate did so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. Indeed, since the customer has no way of knowing when they have hit their peak demand, it is unclear if there is even a price signal being sent. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

[13] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.
[14] *Id.* at 7.
[15] See, for example, http://www.apsloadcontroller.com/ or www.energysentry.com for examples of devices that cost



In a recent rate proceeding, APS revealed that as many as 40% of its customers that recently switched from a two part rate to the optional demand charge rate actually increased their maximum on-peak demand. This means that even among the customers that self-selected onto the demand charge rate (mostly to save money relative to the inclining block standard rate), 40% did not respond to the demand charge price signal in their optional tariff.

It should be noted that APS's current optional residential demand charge tariff was originally approved by the ACC in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning. However, the Commission removed the mandatory requirement less than three years later, noting the change was "in response to complaints that the mandatory nature of the EC-l rate produced unfair results for low volume users." In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-l rate."

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- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- Use Great Caution in the Design of Residential Demand Charges: http://www.raponline.org/document/download/id/7844
- *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs: http://www.raponline.org/document/download/id/7361*
- *Time-Varying and Dynamic Rate Design: http://www.raponline.org/document/download/id/5131*

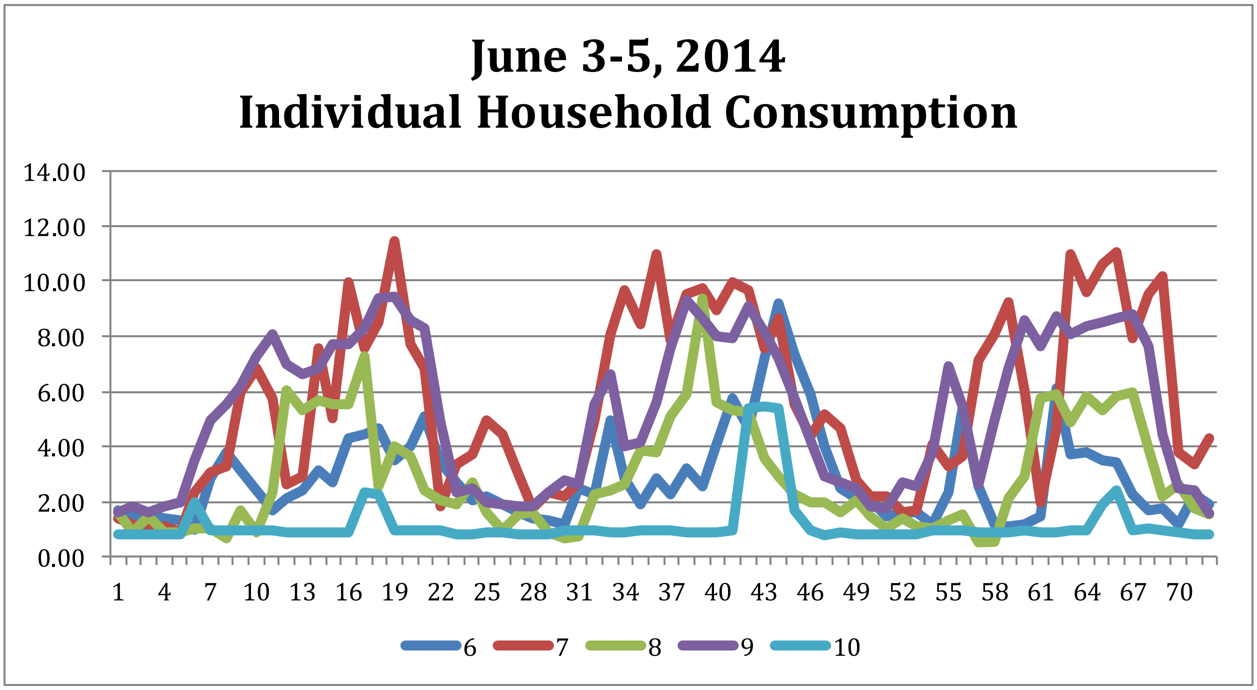
Rocky Mountain Institute
- A Review of Rate Design Alternatives: http://www.rmi.org/alternative_rate_designs

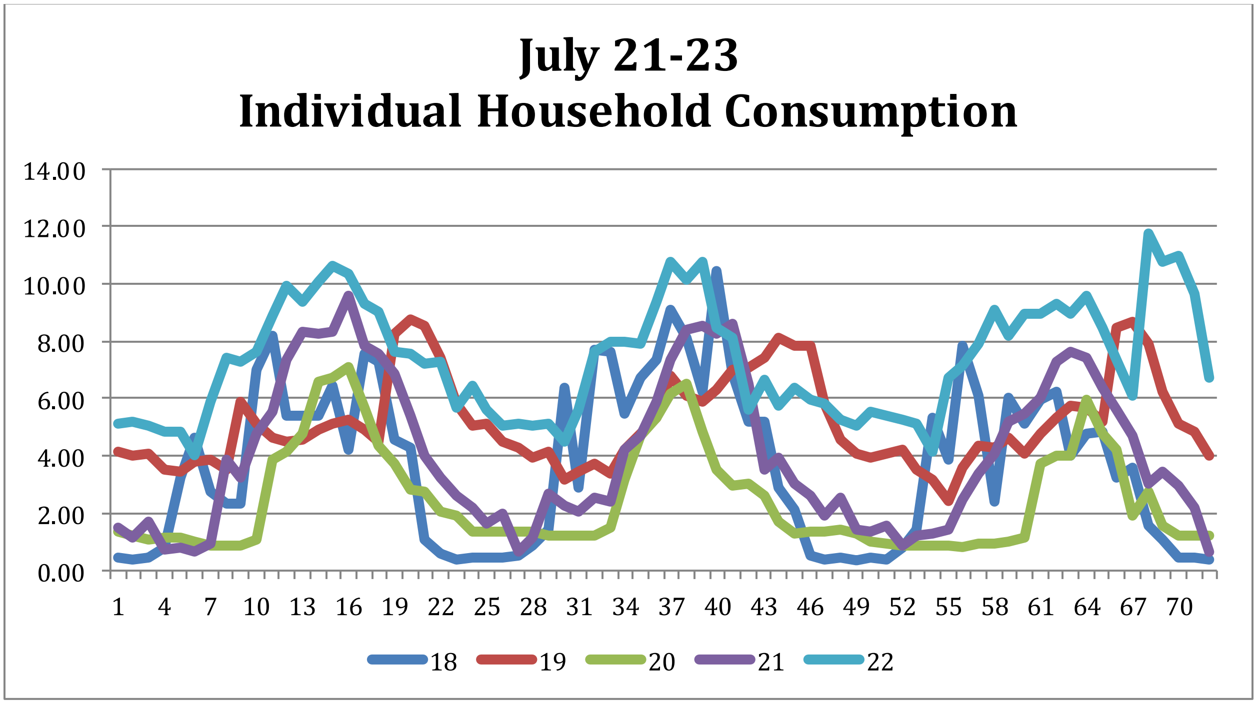
Appendix B: Sample Individual Residential Customer Loads

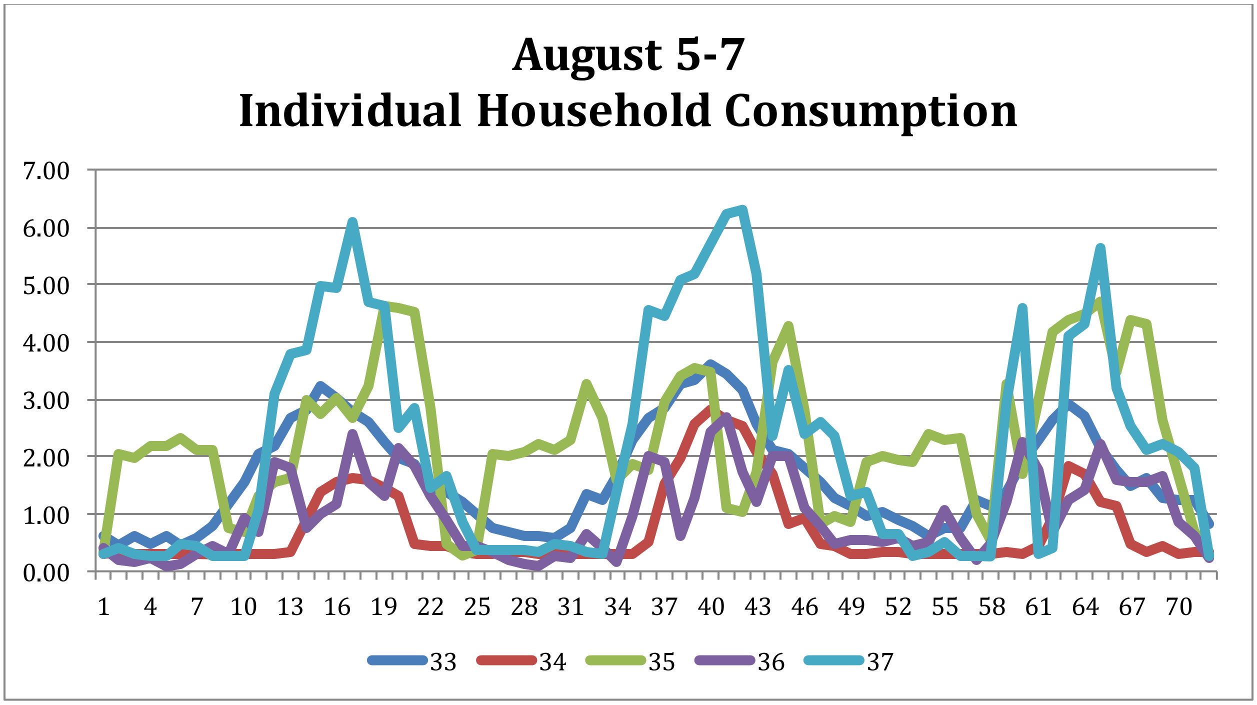
New Mexico

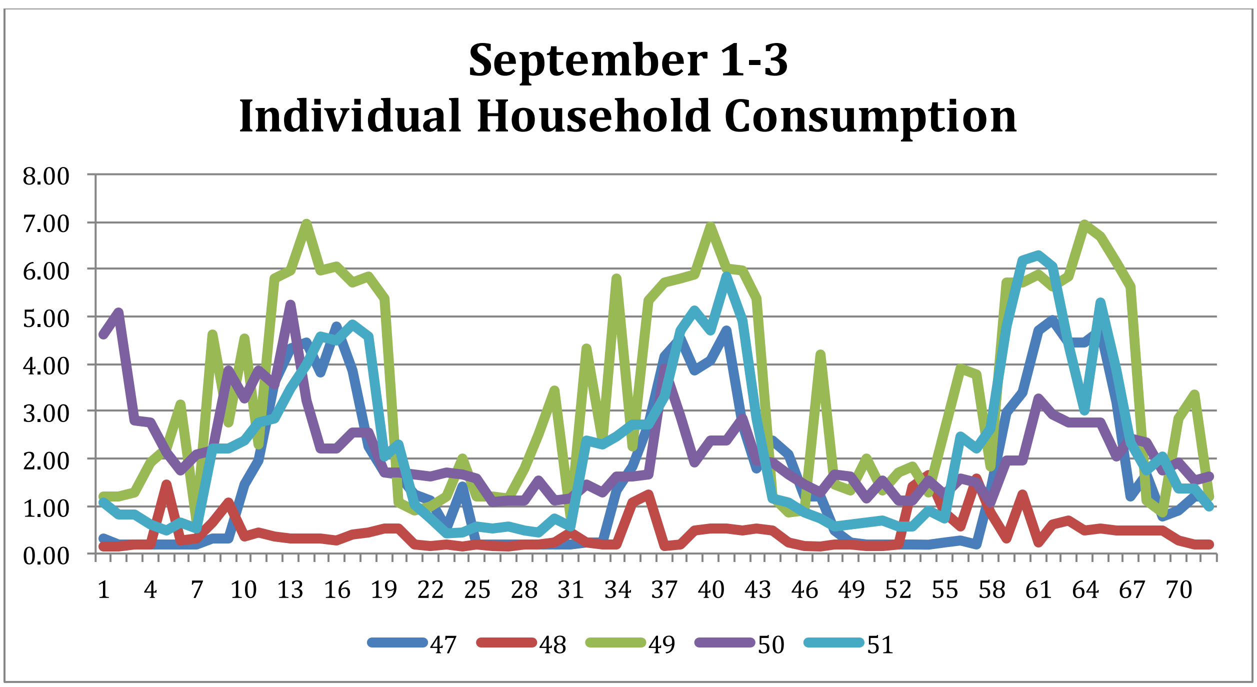
Four summer peak periods; three days and five customers per chart

(middle day is system peak day)





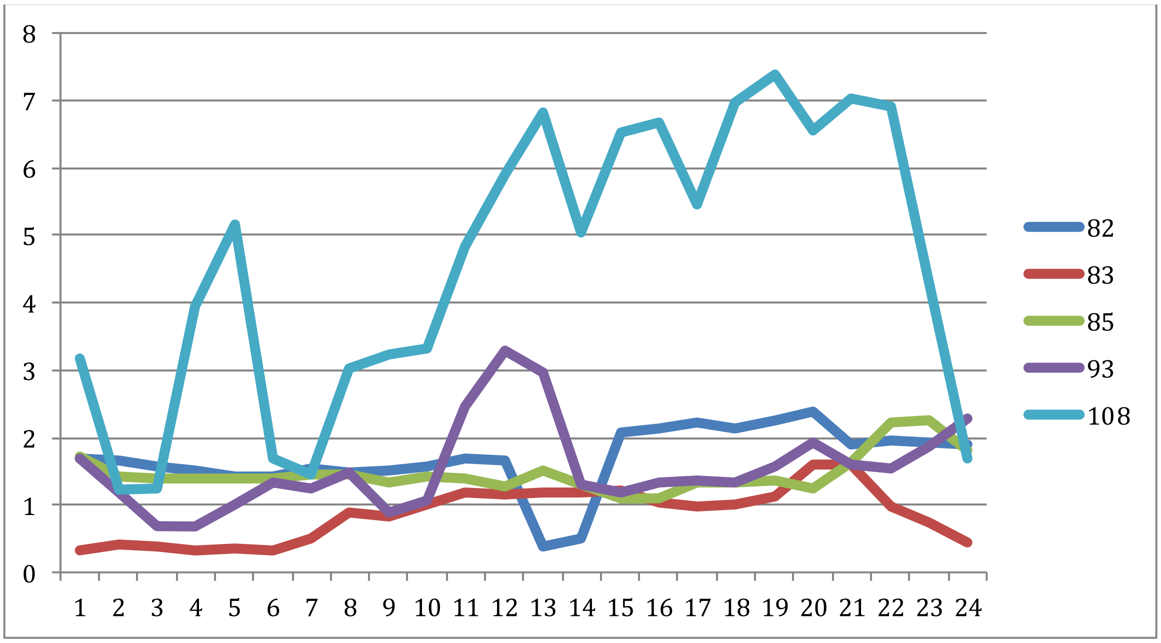

August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33
34
35
36
37


September 1-3
Individual Household Consumption
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
47
48
49
50
51

Colorado

Four summer peak days; five customers per chart

June 27, 2013



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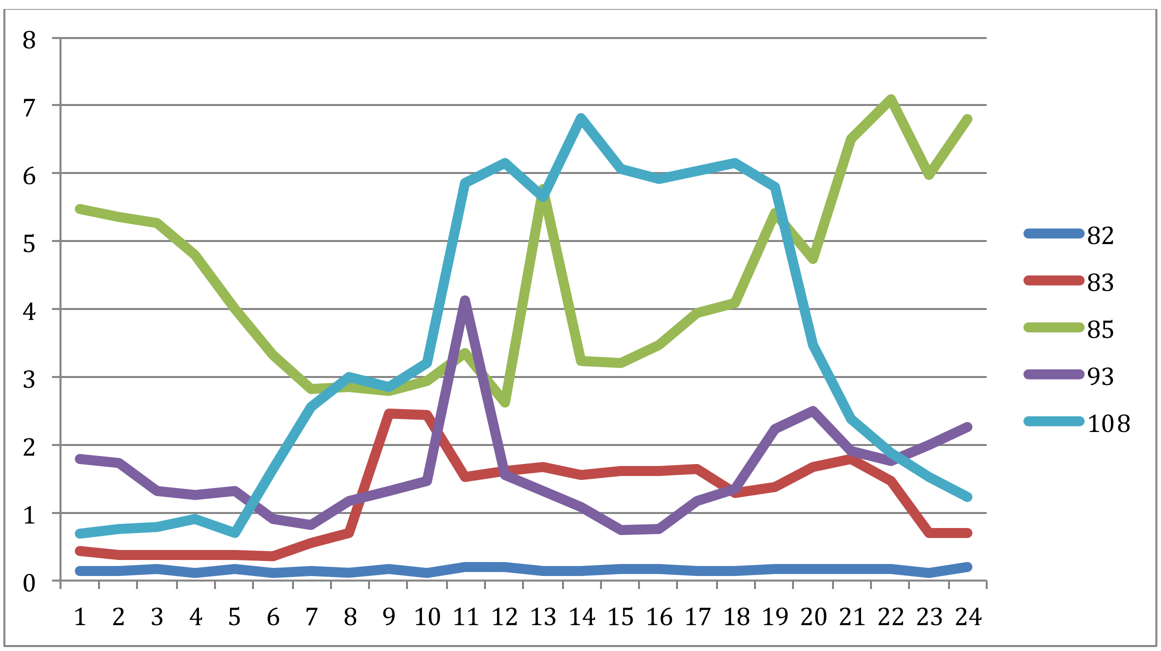

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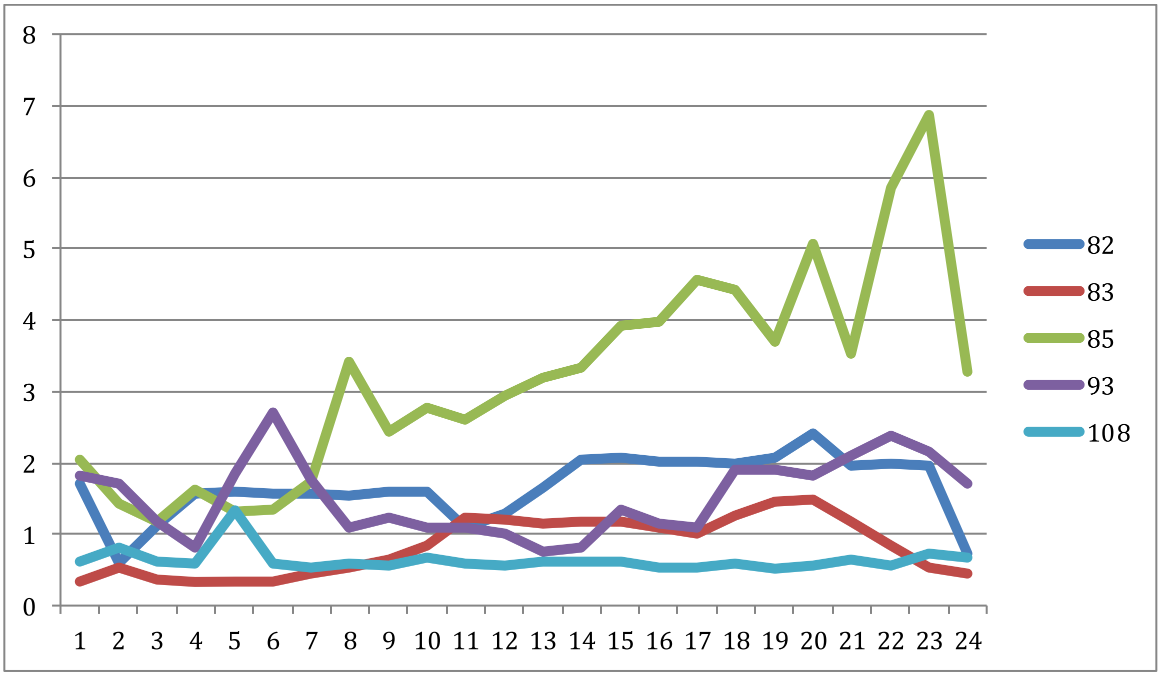
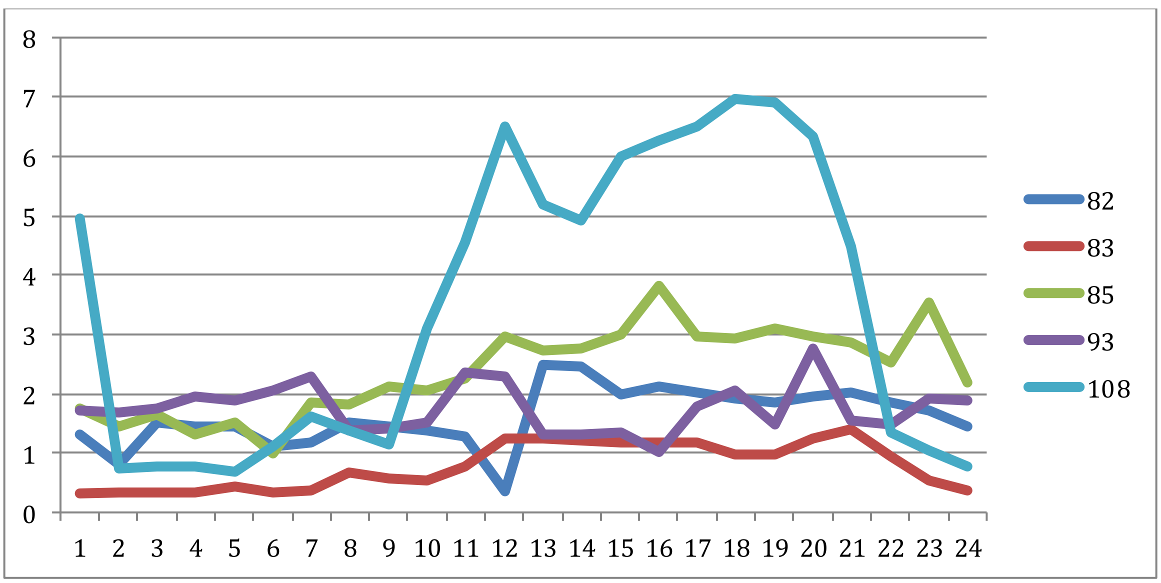


September 6, 2013



Appendix D

Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency

American Council for an Energy-Efficient Economy, 2015.

Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency

Seth Nowak, Brendon Baatz, Annie Gilleo, Martin Kushler,
Maggie Molina, and Dan York

May 2015

Report U1504

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Dan York has more than 20 years of experience in researching, analyzing, and implementing energy efficiency policies and programs. He is widely recognized for his work tracking and analyzing trends and emerging issues in utility-sector energy efficiency programs. His entire educational and professional experience has focused on energy efficiency and conservation as the foundations for a sustainable economy. He joined ACEEE in 2001.

Acknowledgments

This report was made possible through the generous support of the Energy Foundation, N-Star, National Grid, United States Environmental Protection Agency, Pacific Gas and Electric Company, and Connecticut Light and Power/United Illuminating Company. The authors gratefully acknowledge external reviewers, internal reviewers, colleagues, and sponsors who supported this report. External expert reviewers included Janine Migden-Ostrander from Regulatory Assistance Project, Sierra Martinez from Natural Resources Defense Council, and Bryce Gilleland from Pacific Gas and Electric Company. Internal reviewers included Brendon Baatz, Jim Barrett, Neal Elliott, Annie Gilleo, Martin Kushler, Maggie Molina, Steven Nadel, and Dan York. External review and support does not imply affiliation or endorsement. The authors also gratefully acknowledge the assistance of dozens of commission, agency, and utility staff people who generously shared their expertise for interviews, questionnaires, and reviewing case studies. We would also like to thank Fred Grossberg for his assistance throughout the writing and editing process, Kate Hayes and Roxanna Usher for copy editing, and Patrick Kiker and Glee Murray for their help in launching this report.

Executive Summary

Performance incentives for gas and electric energy efficiency play an increasing role in the expansion of energy efficiency programs in the utility sector. These mechanisms address economic disincentives to energy efficiency traditionally faced by regulated utilities. Performance incentives provide financial rewards or earnings opportunities to program administrators, utilities, and shareholders in return for energy savings.

Incentive policies are ripe for examination as major shifts reshape the natural gas and electric utility industry and its regulation, and as efficiency performance incentive policies become more prevalent. This study accordingly updates and expands ACEEE's 2011 report, *Carrots for Utilities: Providing Financial Returns for Utility Investments for Energy Efficiency* (Hayes et al. 2011).

We asked states to submit qualitative information on energy efficiency performance incentives, as well as quantitative information on incentives in the two most recent program years. We analyzed data across all of these states, and also prepared several in-depth case studies. Our findings include the following:

- Twenty-seven states have now adopted incentives based on cost-effective achievement of energy savings targets, of which 25 are currently implementing them, and 2 states' implementation is pending. In 2011, there were 20.
- Fourteen states report having modified or fundamentally changed their incentive mechanisms in recent years.
- Regulated utilities and third-party administrators have achieved savings goals and earned incentive payments in all the states currently implementing incentive mechanisms for which we obtained complete data.
- States with performance incentives in place in 2013 budgeted $23.50 per capita on average for electric energy efficiency programs, 50% more than states with no incentive policy. We found positive correlation in 2011 as well.
- Interviewees indicated that performance incentives influence utility behavior and decision making regarding energy efficiency programs.

Based on our review, we identified four types of performance incentives:

1. *Shared net benefits incentives* provide utilities the opportunity to earn an amount equivalent to some portion of the benefits of a successful energy efficiency program. The amount is usually a percentage of the positive difference between program spending and the dollar valuation of energy savings achieved. (13 states)
2. *Energy savings-based incentives* reward utilities for achieving pre-established energy savings goals measured in kWh or therms. For example, if the utility energy efficiency programs save 100% of target, they are eligible for some particular amount of an incentive payment, often expressed as a percentage of total program spending or budget in a tiered structure. (6 states)
3. *Multifactor incentives* are those in which the calculation of performance incentive amounts include multiple metrics, not only energy savings or energy savings net benefits. For example, financial incentives may be tied to demand savings, job creation, or measures of customer service quality. (5 states)

4. *Rate of return incentives* allow utilities to earn a rate of return based on efficiency spending. This creates a correspondence between demand-side (energy efficiency) spending and supply-side (generation and transmission) investments. (1 state)

As it was in 2011, the trend continues to be for states to adopt mechanisms that incentivize cost-effective achievement of energy savings targets, and to encourage more comprehensive, longer-term performance criteria. The majority of new mechanisms adopted fall into the shared net benefits category. Among states that have modified their incentive mechanism policies, several have adjusted quantitative aspects. These include incremental changes to minimum savings levels and award amount percentages. Others have changed the type of mechanism altogether. The common intention of these changes is to enhance energy efficiency program performance by having the incentive mechanism do a better job of guiding utility and program administrator leadership to meet program goals.

The industry experts we interviewed generally agreed that performance incentives influence utility behavior and decision making regarding energy efficiency programs. Their views are in close alignment with ACEEE's 2011 findings that the ability to assign a dollar value to efficiency investments significantly contributes to utility management's commitment to pursuing energy efficiency.

Since multiple economic and policy factors influence the performance of energy efficiency programs, it can be challenging to isolate and measure the specific impacts of performance incentive mechanisms. This report shows how mechanisms have been effective in various contexts by including twelve case studies providing background, policy details, and performance results on state experience with performance incentives. We conclude that performance incentives are working in combination with other supportive regulatory policies to encourage effective energy efficiency program performance.

Introduction

Utility business models and their regulatory environment are in the midst of historic change. Performance incentives for energy efficiency are part of this change in a growing number of states. These important regulatory tools give financial rewards or earnings opportunities to program administrators, utility companies, and their shareholders for meeting energy efficiency goals.

Utility investments in energy efficiency have greatly increased since the mid-2000s. Whereas utilities invested slightly less than $1.5 billion in energy efficiency programs in 2004, investments had jumped to $7.7 billion per year by 2014 (Gilleo et al. 2014). A number of policy drivers and other factors spurred this investment. Consumers wanted to reduce their utility bills, utilities were being asked to find more economical ways to meet rising demand, and states were looking for cleaner options to meet the energy needs of businesses and residents. Investments in energy efficiency can also create jobs, put more control into the hands of consumers when it comes to how and when they use energy, and help utilities build better relationships with customers.

This increased push to include energy efficiency in utility portfolios did not happen in a vacuum. Many states have adopted regulatory mechanisms to encourage utilities to establish long-term energy efficiency programs. Replacing regulatory practices that impeded the use of energy efficiency as a resource, these new mechanisms have played a crucial role in the expansion of customer energy efficiency programs.

BACKGROUND FOR THIS RESEARCH

Effective regulatory business models are increasingly important as energy savings from utility program portfolios continue to grow. Under traditional business models, cost-effective energy savings involved negative financial impacts and lost opportunities. Now states are increasingly trying to remove the disincentive for utilities to invest in efficiency. As this report will discuss, performance incentive policies have been one of their most effective tools.

This study builds on prior ACEEE research reported in *Carrots for Utilities: Providing Financial Returns for Utility Investments for Energy Efficiency* (Hayes et al. 2011). Since the publication of that report, states providing incentives have gained more experience with them, several new states and utilities have implemented incentives, and many have refined incentive structures already in place. This new report is an updated look at performance incentive mechanisms in states that have implemented or enacted them. We set out to find answers to the following questions:

- What types of performance incentives are being used, and how many states are implementing each type?
- How much money is being invested in each type of mechanism, and how does this compare to total utility energy efficiency budgets and spending?
- Do they work? Do knowledgeable experts at commissions and in the field see the incentives influencing utility behavior?
- What elements should be considered in designing energy efficiency performance incentives in various circumstances?

In answering these questions, we describe incentive structures, report recent data on the dollar amounts awarded, and examine outcomes and lessons learned.[1] We also summarize the insights of regulatory staff and other stakeholders into how performance incentives motivate utilities and other program administrators to institute high-performing energy efficiency programs.

UTILITY ECONOMIC DISINCENTIVES REGARDING CUSTOMER ENERGY EFFICIENCY PROGRAMS

The objective of reducing sales through customer energy efficiency measures is in conflict with the traditional US utility business model. Under this model, regulators set revenue requirements for a utility by aggregating all of its costs of providing service. They then calculate the rates necessary to recover that amount plus some acceptable return to the utility. As noted by the Regulatory Assistance Project (RAP 2011), regulators traditionally rely on two formulas:

Revenue requirement = Expenses + Return + Taxes
Rate = Revenue requirement / Units sold

In the first formula, "Expenses" refers to items such as fuel costs, operations, and maintenance. For the purposes of this explanation, "Return" may be thought of as the utility's profit. The utility is allowed to earn a set rate of return on its capital investments in assets including pipelines, electric generation facilities, and transmission lines.

The traditional business model linking cost recovery to volumetric sales of energy gives utilities the incentive to sell more electricity or gas, which increases revenues and associated profits. Rates are determined by a test year. If the utility can subsequently sell more units of energy than were used to calculate its rate in the test year, it can earn more than its revenue requirement.

This model has worked well for decades to meet its primary goal: to attract the enormous amount of capital needed to build the transmission, distribution, and generation infrastructure for a vast and growing system. Today, however, the model is being challenged by new realities such as slow or no growth in sales, competition from nonutility players, changing business models, and larger roles for energy efficiency and distributed generation (Nadel and Herndon 2014).

The traditional regulatory approach involves a number of disincentives to utility investment in energy efficiency (York et al. 2013). First, the costs of efficiency programs constitute financial losses to utilities unless they can recover those costs through rates or fees. Second, these programs drive down energy use and so reduce utility revenues without lowering the short-term fixed costs of providing service. This goes counter to utilities' incentive to sell more energy and earn more profits—often called the throughput incentive. Third, utilities normally realize a return on their investment when they fund capital assets like power

[1] Some state energy efficiency programs are run by third-party administrators, which we sometimes refer to as utilities. We also call Washington, DC a state for simplicity.

plants. Although efficiency programs reduce the need for this capital spending, they do not provide a comparable return.

REGULATORY APPROACHES TO ADDRESSING DISINCENTIVES

While there are clear disincentives for utilities to invest in energy efficiency under the traditional business model, there are strategies to address these disincentives as a means of encouraging more energy efficiency. Many states have adopted some or all of the following adjustments to the utility regulatory structure, thanks in part to a diverse set of stakeholders who can all agree that energy efficiency presents opportunities to both utilities and the public.

Program cost recovery allows utilities to recover the cost of energy efficiency programs through rates. It is widely accepted and not controversial. Typically, regulators allow utilities to treat efficiency program costs as expenses and to recover them through rate increases. Investments in energy efficiency program are also sometimes capitalized rather than treated as expenses. If capitalized, then the utility may raise rates to earn a return on the funds it invested in efficiency.

Finding a solution to the throughput incentive is a more complicated task. The most straightforward solution is *decoupling*.[2] Decoupling breaks the link between the amount of energy a utility sells and the revenue it can collect (RAP 2011). Rates are adjusted upward or downward as actual sales come in below or above forecast. Thus the utility is able to recover its investment and operating costs independent of actual electricity or gas sales. Conversely, the utility cannot exceed its revenue requirement no matter how much energy it sells. Its revenue is decoupled from the amount of energy its customers use.

Decoupling is in place in 24 states for electric or natural gas utilities or both (Morgan 2012). Three states have electric-only decoupling, 11 states only gas, and there are 10 states with decoupling for both (Gilleo et al. 2014). We count a state as having decoupling if at least one electric or gas utility is decoupled.

As an alternative to decoupling, many states have opted to address the throughput incentive with a slightly different regulatory tool—a *lost revenue adjustment mechanism (LRAM)*. Unlike decoupling, an LRAM does not completely break the link between a utility's sales and its revenues. Instead, an LRAM allows a utility to recover revenues that were reduced, not just due to any cause, but specifically as a result of energy efficiency programs.

There are two other distinctions between decoupling and LRAM. First, LRAM requires a calculation of energy efficiency program energy savings over a given period of time.[3] Decoupling does not require this calculation; it simply compares the volume of total sales to forecasted levels. Second, unlike decoupling, LRAM is generally not symmetrical. As

[2] Decoupling is recommended by ACEEE and numerous industry, nonprofit, and policy groups including the Natural Resources Defense Council, Regulatory Assistance Project, American Gas Association, and others.

[3] In practice, states estimate energy savings to varying degrees, with some putting greater focus on evaluated savings than others.

discussed above, decoupling can result in either refunds or surcharges, depending on whether actual sales are above or below forecast. With LRAM, a utility can recover lost revenues from efficiency programs (under the rationale that it is under-collecting revenues due to reduced sales). However rates are not adjusted downward if the utility experiences a higher volume of sales than predicted in the rate case forecast.[4] LRAM is addressed in detail in a companion report to this one, *Review of Lost Revenue Adjustment Mechanisms* (Gilleo et al. 2015).

While decoupling potentially removes the disincentive to pursue energy efficiency, utilities with only decoupling in place still lack a positive incentive for efficiency, something that utilities and their investors would prefer to have as well.[5] Decoupling may provide a financial benefit to utilities by reducing the risk that efficiency efforts will lower utility returns, and it may make utilities modestly safer investments and more secure borrowers. However benefits are less direct than the ones offered by the traditional model of selling electricity or natural gas for a guaranteed rate. For this reason, utilities, regulators, and other stakeholders have looked for a more direct way to incentivize efficiency investments. Performance incentives can provide that way.

Performance incentives, the subject of this report, offer a utility financial rewards for saving energy through efficiency programs. Incentives allow the utility's energy efficiency activity to be a source of earnings rather than just a pass-through expense. This puts energy efficiency investments on the same footing as other types of utility investments (e.g., in new power plants or transmission and distribution) that are allowed to earn a rate of return. Incentives help compensate the utility for the earnings opportunities it forgoes when it does not have to invest as much in its supply infrastructure because of reduced demand.

PERFORMANCE INCENTIVES

Four Ways to Calculate Incentives

While energy efficiency performance incentive mechanisms vary from state to state, they fall into four general categories of ways to calculate incentives: 1) as a share of net benefits, 2) energy savings-based incentives, 3) multifactor, and 4) rate of return.[6] Virtually all of these performance incentive mechanisms have a threshold level set as the achievement of a minimum amount of energy savings. Some incentive policies may fall under more than one category. Each incentive calculation type is described below.

Shared net benefits. Shared net benefits mechanisms provide utilities the opportunity to earn some portion of the benefits of a successful energy efficiency program that otherwise would all go to the ratepayers. The incentive payment amount is usually a percentage of the positive difference between the costs (efficiency program spending) and the benefits (the

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[4] Some states do have requirements in place meant to prevent utilities from over-earning under an LRAM.

[5] Decoupling approaches vary from state to state, and sometimes differ by utility in the same state. For more information, see RAP 2011. The relationship between a utility's cost of capital and the rate of return allowed by regulators is a determining factor concerning whether the disincentive for efficiency has been effectively removed or not. Also see Kihm 2009.

[6] There are many ways to categorize incentive mechanisms. See also the similar but not identical categorization in Cappers et al. 2009.

dollar valuation of energy savings achieved as a result the program). This category has a savings-based element, in that most of them have a threshold level set as the achievement of a minimum percentage of the energy savings performance goal for the utility. We call it shared net benefits because the incentive amounts are driven by net benefits; the greater the net benefits, the higher the incentive payment amount.

Energy savings-based. Savings-based incentives reward utilities for achieving, and sometimes for exceeding, pre-established energy savings goals, measured in kWh or therms. Often, these energy savings targets for utilities may be tied to or derived from statewide energy efficiency resource standard (EERS) policies. For example, if the utility energy efficiency programs save 100% of target, they are eligible for some particular amount of an incentive payment. Five of the six states with savings-based incentives have EERS. The amount of the financial incentive the utility earns is often calculated as a percentage of total program spending or budget in a tiered structure (e.g., achieve 100% of the savings target, receive an amount equivalent to 6% of the program spending; achieve 110% and receive 8%; and so on), but driven by the program energy savings achieved.

Multifactor mechanisms are those in which the calculation of performance incentive amounts are more complex and include multiple metrics. Energy savings are just one of several metrics that are used to determine the amount of incentive earned. This type of approach is found in a handful of states where the mechanism is used to forward the achievement of several regulatory and public policy goals at the same time. For example, financial incentives may be tied to demand savings, job creation, or measures of customer service quality.

Rate of return incentives are a fourth approach and are far less common. Rate of return incentives allow utilities to earn a rate of return based on efficiency spending. This creates a correspondence between demand-side (energy efficiency) spending and supply-side (generation and transmission) investments. For example, a utility may earn a rate of return for efficiency investments equivalent to or comparable to the rate it earns for new energy supply capacity investments.[7]

The Special Case of Non-Utility Program Administrators

An additional special category of performance incentives applies to situations where states have non-utility program administrators for their utility ratepayer-funded energy efficiency programs. These companies are contracted third parties that administer and implement energy efficiency program portfolios. Many of the concerns about utility earnings opportunities do not apply in these circumstances. As a class, the contract administrators in these cases differ from investor-owned utilities in their organizational and financial structures and the regulatory and policy frameworks in which they operate.[8] Examples include Efficiency Vermont, Wisconsin Focus on Energy, and Hawaii Energy. The common

[7] Amortizing the recovery by the utility of the cost of programs over multiple years may also be considered a rate of return incentive in some instances, if the utility earns a return on the balance after the first year.

[8] Municipal utilities, a third category of energy efficiency program administrator in addition to investor-owned utilities and third-party administrators, will be the topic of upcoming ACEEE research.

element for the purposes of this study is the desire to incentivize good performance by whoever is administering the programs. Third-party administrators have argued that performance incentives motivate excellence and maximize savings and cost-effective performance.

Therefore we have included non-utility program administrators along with the investor-owned utilities in our discussion of the four ways of calculating incentives. As it turns out, all of the currently operating independent administrators that have incentive mechanisms also have multifactor performance incentives. However the structures and calculation methods of the incentive mechanisms vary substantially from state to state. We discuss the details later in this report.

Methodology

We sent research questionnaires to public utility commission staff in each state that our records indicated had implemented performance incentive policies or where policies were pending. We only reached out to states for which our previous research had identified energy efficiency performance incentives.[9] Commission staff were asked to submit both qualitative and quantitative data on the incentive structures in place for electric utilities, gas utilities, or both. In total, we emailed questionnaires to 43 individuals, almost all of whom are public service commission staff members, in 29 states. We found that in some states performance incentives were no longer in effect or had not yet been implemented. In those cases, we did not make any further attempts to include them in our analysis or discussion in this report.

The questionnaires requested qualitative and quantitative data. We asked respondents about the nature and structure of the performance incentive mechanism or mechanisms in their state, and requested them to provide citations and documentation. The quantitative data we asked for (on two utilities, for two program years, for up to two mechanisms) was the incentive amount, total energy efficiency program costs (spending or budget), and energy savings achieved in kWh or therms. See Appendix B for a copy of the questionnaire.

In instances where we did not obtain a completed research questionnaire, we collected some of the data through phone interviews, regulatory filings, or other documents. Some of our state contacts returned the questionnaire but indicated that at least some of the data we had requested was unavailable or unclear. In particular, some states did not have the numbers ready for recent program years due to the length of their regulatory processes. For example, procedures for estimating energy savings or conducting evaluation, measurement, and verification of those results, and then having finalizing the amounts of the performance incentive, may take years in some cases.

[9] Our previous research includes Hayes et al. 2011 and Gilleo et al. 2014. It is possible that we missed additional states with utility incentives policies in those projects, in particular if they use a rate of return approach to amortize program costs and may not have categorized it as a performance incentive. For a recent listing of performance incentive policies by state, see IEI 2014.

Next we identified states representing a diversity of types of incentive mechanisms for additional research, making an effort to include those states leading the nation with the most extensive or exemplary energy efficiency portfolios and policies, states with geographic diversity, and a diversity of program-administrator types. For these, we conducted more extensive phone interviews with our contacts to get a deeper understanding of how the incentives function in practice, how they were intended to work in those states, and lessons learned. We then chose a group of these states to examine more closely for case studies. Case studies of Arizona, Arkansas, California, Indiana, Massachusetts, Michigan, Minnesota, Missouri, Oklahoma, Rhode Island, Texas, and Vermont are in Appendix A. The last steps in the data-gathering process were telephone interviews with other key stakeholders in this smaller subset of states, including utility representatives, consumer counsels, and advocates, and follow-up documentary research for the case studies.

Results

Our research identified 27 states with performance incentives for electric energy efficiency and 16 for natural gas energy efficiency. All states with incentives for gas efficiency also have incentives for electric efficiency. A few state respondents indicated that their states have performance incentives established for all regulated utilities. In other cases incentives for energy efficiency only apply to a subset of utilities in the state. Many energy efficiency performance incentives have been in place for a decade or more; most have been revised or reformed via legislation or new regulation in a series of iterations. Mississippi and West Virginia have not implemented their mechanisms yet.

Figure 1 shows the primary incentive mechanism type by state.

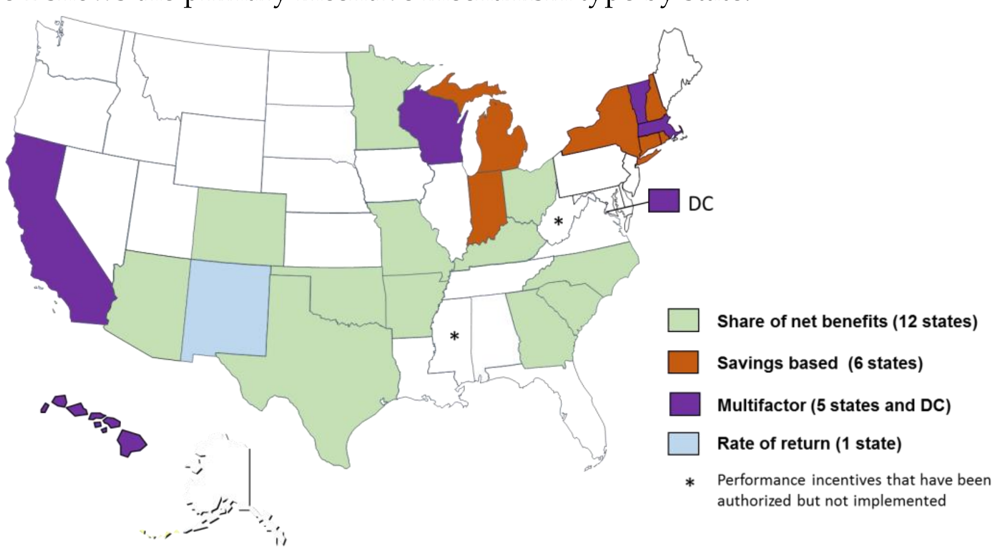

Figure 1. Primary incentive mechanism type by state. Incentive may apply to one or more regulated utilities, or to a statewide program implementer. Individual state information on performance incentives for electric and natural gas energy efficiency may be found on the ACEEE state energy efficiency policy database at http://aceee.org/sector/state-policy.

Shared net benefits energy efficiency performance incentives are the most common, seen in 13 states. We count Massachusetts in this group, although until the end of 2014 the calculation of incentives included additional performance indicators. Energy savings-based incentives are the second-most prevalent mechanism type, with six states employing this approach. Washington, DC and four states use multifactor approaches. One state, New Mexico, pays a rate-of-return incentive on energy efficiency program investments paid by the utilities.

Of the 16 states with both gas and electric energy efficiency performance incentives available, none indicated that there are significant differences between the incentive mechanisms as applied to electric versus gas utilities.

Performance Incentives: Historical Background

The historical origins of performance incentives and their rationales vary from state to state. While there are some common themes, the regulatory, policy, and economic circumstances differ enough to defy generalization, as seen in these examples.

Massachusetts' first incentives were for New England Electric in the early 1990s. The state lowered the level of performance incentives and introduced decoupling during the mid-1990s. The primary motivation for having performance incentives has been to achieve energy savings goals. The ability of the utilities to earn a return on energy efficiency spending persuades them to align their goals with public policy goals.

Since the 1980s California had decoupling in place. However, in an effort to move toward deregulation during the late 1990s, California suspended decoupling. After the 2001 electricity crisis occurred, the state then reinstated decoupling over the next three years and moved to expand energy efficiency. In 2005, the California Public Utilities Commission added performance incentives in the form of the Risk Reward Incentive Mechanism to encourage greater efficiency. Unlike many states, the regulations at that time also included financial penalties if program performance results were not sufficiently in line with energy savings goals.

Oklahoma's utility performance incentives arose from an investor-owned utility approaching the Corporation Commission in a rate case, resulting in a commission order requiring the development of quick-start energy efficiency programs. The utility came back with a proposal including programs, a rider for cost recovery, lost revenue recovery, and a 25% shared-savings performance incentive mechanism. When it came time for full compliance programs, i.e., no longer only quick-start, the utilities were still allowed to seek lost revenues attributable to energy efficiency through an LRAM. The incentive was reduced from 25% to 15%. Oklahoma has decoupling for gas, but not electric utilities.

In Rhode Island, energy efficiency programs and utility performance incentives were both instituted years prior to decoupling. Performance incentives for energy efficiency were viewed at that time as one factor that allowed the utilities to support least-cost procurement.

Vermont's statewide energy efficiency utility, Efficiency Vermont, has had quantitative performance indicators to determine the financial incentives since 2000. Vermont Energy Investment Corporation (VEIC) was hired explicitly on a performance-based three-year contract basis, so having incentives was a logical element. In 2011 VEIC was engaged as an efficiency utility via a long-term order of appointment, but the performance incentive continued.

DESCRIPTIVE RESULTS

While the circumstances in which energy efficiency performance incentive mechanisms arose vary considerably from state to state, there are common aspects to how the mechanisms themselves are structured. Almost all have a threshold, or minimum percentage of an energy savings goal, which the utility must exceed in order to be eligible for earning any incentive. Similarly, almost all incentive mechanisms have a cap, or maximum limit, on the amount. Some caps are absolute dollar amounts, such as in those states that budget a set pool of funds from which incentives may be awarded. Other caps are relative, expressed as a maximum percentage of program budgets or percentage of total net benefits. A third near-universal characteristic is that they all provide greater rewards for additional energy savings up to the level of the maximum incentive.

The following three tables summarize three aspects of the mechanisms: threshold, structure, and cap. The first table provides information on states with shared net benefits incentives, the second is for savings-based incentives, and the third is for multifactor incentives. Some of these state policies have elements of more than one type of incentive. In those cases, we list the state in the category with which it shares the main characteristics.

Reading the Tables

Threshold requirements. The left-hand column shows threshold requirements, i.e., minimum requirements for the incentive to be awarded. These are most frequently expressed as a minimum energy-savings performance measure that must be met for the utility or program administrator to be eligible, or potentially eligible, for financial incentives. For energy savings as a percentage of the utility goal or target, the minimum ranges from 50% to 100% of goal for those that have a minimum.

Overall incentive structure. The center column, overall incentive structure, briefly summarizes distinguishing elements of the incentive mechanism basis or calculation.

Cap or maximum incentive. The right-hand column, the cap or maximum incentive, indicates if there is a limit on how much a utility or administrator may earn for extraordinary energy efficiency program portfolio performance, and if so, how the limit is described or determined. Some of the caps are statewide or for all regulated utilities rather than on a by-utility basis. For example, a statewide pool of funds may be allocated to utilities based on their relative performance to each other, or their performance may be independently considered against a predetermined energy savings goal.

Shared Net Benefits

As shown in table 1, the most common thresholds for shared net benefits mechanisms are in the range of 70–85% of energy savings targets. Typically the amount of the incentive itself is calculated as percentage of the net benefits of energy savings achieved. The types of caps vary.

Table 1. Shared net benefits utility performance mechanisms overview: threshold, structure, and cap

State	Threshold requirements	Overall incentive structure	Cap or max incentive
AR	80% of net energy savings target	10% of net benefits with cap	Range from 4% to 8% program budgets
AZ	85% of gross savings goal	For 2013, 6–8 % of net benefits; capped based on percent of program costs. For 2014, $0.0125 per kWh saved.	$0.0125 per first-year kWh saved starting in 2014
CO	80% of net energy savings goal	1% net benefits for 80% of savings goals, 5% at 100%. 1% more for each 5% to max 15% at 150%. $5 million pretax disincentive offset for > 100% of electric savings goals; $3.2 million if 80-99%.	$30 million max performance incentive and disincentive offset
GA	50% of projected net energy savings	8.5% NPV actual net benefits of verified kWh savings. If annual incremental kWh savings is less than 50% of projected, will be 0.5% for demand response (DR) measures and 3% for energy efficiency (EE) measures.	No cap
KY	None	From 10% to 15% of net benefits for EE programs, excluding public education and pilot programs.	No cap
MN	Energy savings = lesser of 0.4% of retail sales or 50% of last five years' average gross savings	As energy savings levels increase to 1.5% of retail sales, utilities receive an increasing share of net benefits, up to an incentive level of and average of 7 cents per first year kWh saved. Varies by cost effectiveness of implemented projects.	Average incentive may not exceed $0.0875/first-year kWh saved or $6.875/MCF, nor exceed 20% of net benefits
MO	70% of approved three-year net savings target	Tiered or graduated scale, ranging from 70% to 130% of cumulative three-year savings target. Specifics vary by utility. For example, achieving 70% of savings goal pays 4.6% of net benefits, up to 6.19% for 130% or more, for Ameren Missouri. Others similar.	Percentage shared net benefits capped per utility; no cap on dollar amount
NC		Data not available	
OH		Data not available	
OK	2015 will be pass cost-effectiveness test and 80% of net goal savings	15% of net benefits	Previously no cap; in 2015 the cap will be 15% of net benefit
SC	Programs as a whole must pass the UCT	(6% SCE&G; 11.5% DEC) * [(net kWh and kW savings over measure life * avoided costs) – program costs] Amortized over five years for SCE&G	No cap
TX	100% of gross savings goal	1% of the net benefits for every 2% that the demand reduction goal has been exceeded	Max of 10% of a utility's total net benefits

Source: Public utility commission staff responses to questionnaires

Savings-Based

For savings-based mechanisms, shown in table 2, all the threshold requirements include achieving a minimum percentage of energy savings goals. The most frequent method of calculating incentive amounts is a tiered percentage of energy efficiency spending that increases as energy savings performance does relative to savings targets. Caps are also typically calculated as a percentage of energy efficiency spending.

Table 2. Savings-based utility performance mechanisms overview: threshold, structure, and cap

State	Threshold requirements	Overall incentive structure	Cap or max incentive
CT[1]	75% of net savings goals for 2014; for 2015, threshold is 80%	In 2014, 2% of program spending at 75% of saving goals. At 135% or more of a goal, max is 8% of program spending. Awarded on a scale. 80% of savings goals earns 2.5%.	8% of program costs
IN	60% or 65% annual gross kWh savings target achieved	IPL, Vectren, and Duke have tiered structures tied to program costs. I&M has a shared savings mechanism. Structure ties level of kWh achieved relative to set target to a percentage of program costs that the utility may receive as performance incentive.	15% of program costs
MI[2]	Utility System Resource Cost Test (USRCT) of 1.25 and minimum 100% target savings	Sliding-scale incentive awarded when net savings exceed 100% of target, starting at 5% of spending; varies by utility. Highest rate of incentive for savings performance is 10%.	Lesser of 25% of net benefits or 15% of program costs
NH	Benefit-cost ratio of 1.0 and 55% of plan savings. Apply separately to residential and commercial and industrial sectors.	Electric utilities: 7.5% at and above 55% total lifetime energy savings; 6.0% applies below 55% total lifetime energy savings. Natural gas utilities: baseline incentive of 8%.	Electric: max 10% at 55% savings and up; 8% under 55%. 5% cap each on kWh and cost effectiveness components. Gas: 12% of costs
RI	75% of target net savings	Target incentive is 5% of spending budget.	Max incentive 6.25% of approved spending budget

State	Threshold requirements	Overall incentive structure	Cap or max incentive
NY[3]	80% of the utility's net savings goal	Linear increase from 80% to 100% of each utility's share of statewide total. Step 1 incentive: 90% of maximum possible award if utility achieves 100% of its savings goal. Step 2 incentive: remaining 10% share of statewide maximum as bonus if statewide savings goal achieved.	100% of utility share of statewide $50 million pool for gas and electric over four years based on percentage savings goals

[1] One respondent in Connecticut summarized its performance incentive mechanism type as rate of return, although many of its features are of the savings-based type. [2] Michigan performance incentives for energy efficiency vary by utility and may reward multiple performance outcomes including minimum numbers of low-income customers served, demand savings, and participation in certain multi-measure programs. While predominantly saving-based, they might also be reasonably grouped with multifactor incentives. [3] New York has expressed the maximum amount of the incentive pool both as a percentage of total program costs and in terms number of basis points of the return on equity of an investor-owned utility. *Source:* Public utility commission staff responses to questionnaires.

Multifactor

The multifactor mechanisms are more varied from state to state, as shown in table 3. Where the energy efficiency programs are run by third-party administrators, the performance incentives accrue to those companies, not the electric and gas utilities.

Table 3. Multifactor performance mechanisms overview: threshold, structure, and cap

State	Threshold requirements	Overall incentive structure	Cap or max incentive
CA	No minimum level of energy savings specified in the CPUC order. Incentive amounts are a linear function of net lifecycle savings in kWh, MW, and MMTherms multiplied by an earnings rate coefficient.	Energy savings performance award, 9% of resource program budget (minus codes and standards [C&S]) used to determine lifecycle savings coefficients; ex ante review performance award, 3% of budget times Engineering Compliance Score; C&S program management fee, 12% of C&S program budget spending; non-resource program management fee, 3% of non-resource program budget spending.	Now: up to percentages listed for each area. Was: risk/reward incentive mechanism, capped at $150 million/year for all IOUs.
DC	Reduce per-capita energy use, add renewable generating capacity, reduce peak electricity demand growth, improve low-income housing EE, reduce largest energy users' energy demand growth, add green jobs	Contractor gets 25% of at-risk compensation allocated per benchmark for electricity consumption reduction = 0.5% annual reduction in 2009 weather-normalized electricity consumption in DC. Each 0.25% beyond initial 0.5% contractor gets additional 12.5% of incentive allocated to this benchmark.	Maximum at-risk compensation in Year 1 of $300,000, increasing up to $800,000 in program years four through seven
HI	75% of target for each indicator, including first-year kWh savings, peak demand reduction, total resource benefit, inter-island equity, and others	The contract administrator proposes targets for each indicator (e.g., XX GWH in energy savings). Each target includes 75% minimum and 125% maximum achievement amount. Financial incentives are based on percentages allocated to each indicator.	Yes. Incentive amount is flat $700,000; may earn extra $133,000 for performance 25% above target.

State	Threshold requirements	Overall incentive structure	Cap or max incentive
MA *	Statewide threshold 76.72% of savings goal; adjustments for each program administrator.	Statewide incentive pool allocated to: (1) 56% savings mechanism, (2) 35% value mechanism, (3) 9% performance metrics; set payout rates for savings and value components, incentive thresholds, and caps	125% of incentive amount related to the achievement of target savings for each utility.
VT	Efficiency Vermont (EVT) has a number of quantifiable performance indicators (QPIs). Each has a different threshold. Some are minimums, where EVT loses some fraction of incentive if it fails to reach threshold. Others scale down, with no minimum.	EVT has QPIs. Some are minimums that result in reductions to EVT's compensation if not met. Others scale up with increased performance. Incentive structure was based on prior three-year performance period. QPIs for 2015–2017 period include performance indicators (PIs) and minimum performance requirements (MPRs).	For 2015–2017, cap is 4.5% of implementation budgets. Of that, split is 40% operations fee, 60% incentives. For some QPIs, cap varies by indicator.
WI	Based on annual gross life-cycle energy savings and demand reduction of 6 million MWh, 288,000 thousand therms, and 83.77 MW.	Set amounts (not sliding scale) available for performance more than 120% of annual savings goal and for customer service measures; includes penalties for under-achievement on all metrics.	$750,000 total maximum for the four-year period

* Current Massachusetts regulation has removed the 9% for performance metrics, meaning that the performance incentive mechanism going forward may no longer be best categorized as multifactor incentive. The description here applies to the mechanism as it was in 2014. *Source:* Public utility commission staff responses to questionnaires.

The diversity of incentive mechanism structures and methods of calculation in the multifactor incentive group reflects both the intended performance outcomes (i.e., those components in addition to cost-effective energy savings) and the types of organizations (i.e., not only utilities). See examples of multifactor incentives in table 4.

Table 4. Multifactor performance incentives components and type of program administrator by state

State	Administrator or program name	Multifactor mechanism components (abbreviated list, illustrative only)	Administrator organization type
DC	DC Sustainable Energy Utility	Contract includes benchmarks for per-capita energy consumption, renewable energy generating capacity, growth of peak electricity demand, energy efficiency of low-income housing, growth of the energy demand of DC's largest energy users; and the number of green-collar jobs	Third-party administrator: nonprofit energy services organization
HI	Hawaii Energy Efficiency Program	Energy savings, net benefit, demand reduction, island, and other factors	Third-party administrator: for-profit private contractor

State	Administrator or program name	Multifactor mechanism components (abbreviated list, illustrative only)	Administrator organization type
MA *	Regulated utilities	56% savings mechanism (total benefits), 35% value (net benefits) mechanism, and 9% to performance metrics. Metrics include number of correct installations, market penetration, and others.	For-profit investor-owned utilities
WI	Wisconsin Focus on Energy	Annual gross energy savings targets. Key performance indicators (KPIs), customer satisfaction measured versus baseline and days incentives outstanding (a measure of how quickly participants get financial incentive payments).	Third-party administrator: For-profit private contractor

* Current Massachusetts regulation has removed the 9% for performance metrics, meaning that the performance incentive mechanism going forward may no longer be best categorized as multifactor incentive. The description here applies to the mechanism as it was in 2014. *Source:* Public utility commission staff responses to questionnaires.

Rate of Return

We do not include a table displaying rate-of-return incentives, because New Mexico is the only state we surveyed to have a rate-of-return mechanism in place. We define rate-of-return mechanisms as those that provide a financial return on energy efficiency spending without tying the financial award directly to energy savings.[10] This is in marked contrast to other states that pay incentives for energy efficiency portfolio performance, whether as measured by energy savings, the net benefits of energy savings, or those metrics combined with additional quantified performance outcomes, as is the case with multifactor incentive mechanisms.

There is no minimum energy savings threshold for New Mexico's regulated investor-owned electric and gas utilities to be eligible for the financial incentive. However there is an indirect performance threshold because program spending is budgeted to be 3% of utility retail sales, evaluated programs must meet cost-effectiveness criteria, and there is a statewide energy efficiency resource standard. By stipulation, regulators have established an annual incentive for calendar years 2014–2016 that is equal to 7% of program expenditures; both efficiency spending and incentives are budgeted by utility and then trued up annually. Utilities must demonstrate that the energy efficiency programs they propose to the New Mexico Public Regulation Commission are cost effective using the total resource cost test (TRC) and the utility cost test (UCT).

[10] Kentucky statute also allows the commission to approve a financial return on efficiency spending; in practice, they have used a shared net benefits approach. Amortizing the recovery of the cost of programs over multiple years may also be considered a rate of return incentive in cases in which the utility earns a return on the balance after the first year. This is the case in Maryland. Vermont Gas Systems (VGS) receives a return on approved energy efficiency spending and their recovery of energy efficiency costs is amortized over three years. This was not considered to be a performance incentive by those we spoke with in Vermont.

COMPARATIVE RESULTS

To provide a quantifiable basis for analysis of these types of incentives, we examined incentive amounts relative to energy efficiency program costs. We recognize that there are many differences among jurisdictions in terms of policies and performance. Comparing ratios of incentive amounts to program costs is still a useful and straightforward means of comparison. Note that the following data are not normalized by the extent to which energy savings goals were achieved or exceeded, nor are these organized into tiers by the absolute levels of energy-efficiency spending or savings.

To make these comparisons, we collected data on the dollar amounts of performance incentive financial awards by utility for the two most recent program years or program cycles for which these amounts were readily available. Most states submitted data for the largest one or two regulated investor-owned utilities, as we had requested. In most cases these were electric utilities. As one means of normalizing the data across states, we calculated the ratio of incentive amount to energy efficiency program cost by utility or program administrator. For energy efficiency cost, we used either total annual program spending or budget, as provided by regulatory staff contacts.

Next we sorted the utilities into groups by type of incentive mechanism employed in their respective states applicable to the reported utilities. This provided us with data for the ratio of performance incentive amounts to annual energy efficiency costs. For years in which both data points were available, there were 24 instances of shared net benefits, 14 of utilities with savings-based incentives, 12 of administrators or utilities with multifactor incentives, and 1 rate of return mechanism, for a total of 51 data points. These data are presented as reported by respondents and therefore may vary in their methods of calculation across states. Our aim is to provide a relative basis for comparison and contrast, not to claim a definitive measure.

In figure 2, the gray boxes indicate the inter-quartile range of data around the median. The vertical lines indicate the full range from the lowest to highest.

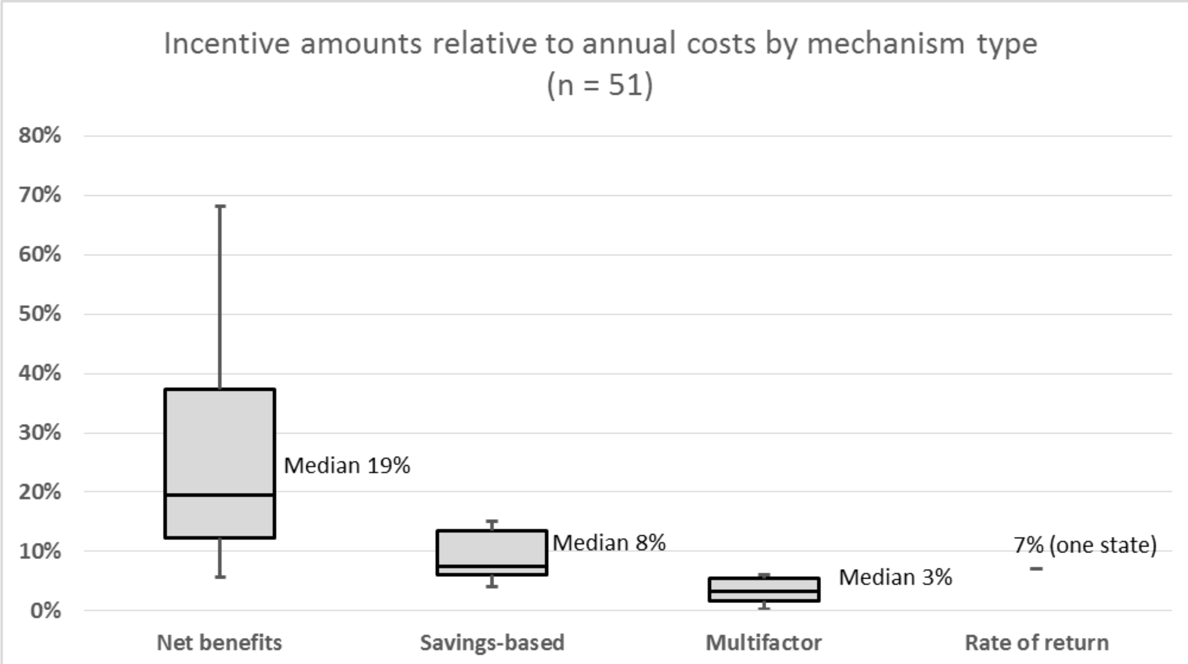

Figure 2. Incentive amounts relative to total annual energy efficiency costs by mechanism type. *Source:* Derived from public utility commission staff responses to questionnaires.

Shared Net Benefits

The eight states reporting performance incentives based on the net benefits provided by energy efficiency pay out, on average, the highest financial awards relative to annual costs. Often, the benefits are calculated over the full measure life and not just for one year. This means the incentive is front-loaded.[11] This may be one reason net benefit incentive amounts are often higher than is the case with other approaches. They are still generally lower than earnings on supply-side investments over the life of those investments, realized in net present value.[12] Of the 24 ratios reported here, the highest is 68%, the lowest is 6%, and the median is 19%. This is significantly higher than the ratios in states using other approaches to calculating incentives. Only 7 of the 26 award amounts reported from states using multifactor or energy savings-based incentive calculation methods were 8% of energy efficiency program costs or higher. The highest ratios in the data set in the chart are from 2011 and 2012 for two Minnesota electric utilities and are not representative of incentive amounts for the majority of shared net benefits mechanisms. These utilities had neither LRAM nor decoupling mechanisms in place during those years, which may partially explain the higher ratios. For further discussion, see the Minnesota case study in Appendix A.

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[11] States have a variety of approaches to how they calculate net benefits and how many years constitute the measure lives. Often measure lives are determined in a technical reference manual (TRM).

[12] See https://www.pge.com/regulation/EnergyEfficiencyRisk-RewardIncentiveMechanismOIR/Pleadings/NRDC/2010/EnergyEfficiencyRisk-RewardIncentiveMechanismOIR_Plea_NRDC_20101206_203020.pdf.

Savings-Based

The savings-based award-to-cost ratios are generally in the middle of the dataset in terms of incentives as percentage of spending, though substantially below net benefits, as seen in figure 2. Of the 14 energy savings-based award amounts included here, relative to energy efficiency costs, the ratios ranged from a low of 4.2% to a high of 15%, with a median of 8%. As defined above, savings-based incentives reward utilities for achieving pre-established energy savings goals, measured in kWh or therms. These may be tied to or derived from statewide energy efficiency resource standards (EERS). For utilities that over-comply with energy savings goals, i.e., achieve more than 100% of their targets, the maximum incentive dollar amounts impose an upper limit on how much energy savings beyond target is eligible as well, since the two are tied together.

While the amount of the financial incentive the utility may be eligible for is generally expressed as a percent of total program spending or budget in a tiered structure or a proportionate scale, we have chosen not to describe these as spending-based incentives, since eligibility is based on savings, not spending. Also, the term "savings-based" distinguishes them from those we are calling rate-of-return incentives.

Multifactor

Multifactor incentive amounts are the lowest when compared per dollar of costs budgeted or spent on efficiency programs. The median for multifactor awards is 3% as a percentage of energy efficiency spending. The highest multifactor ratio is 6.5%. The lowest ratio included here is approximately two-tenths of 1%, for Wisconsin Focus on Energy, a third-party administered portfolio. This ratio is derived from the highest incentive payout possible to the contract administrator under the contract; the actual amount for the first four-year period has yet to be calculated and paid out and is contingent on both energy savings and customer service metrics.

Most multifactor energy efficiency performance incentives are for third-party administrators. This subcategory of multifactor incentives has the lowest awards as a percentage of program costs. The incentives they receive or may be eligible for, for meeting and exceeding energy savings goals, average just 1.8%, ranging from 0.2% up to 3.5%.

Performance incentives for non-utility program administrators generally are structured and perform differently than those for utilities. This is not surprising because third-party administrators are different economic entities than investor-owned utilities. For example, they do not have the revenue-loss disincentive that utilities face with regard to customer energy efficiency. Also, program administrators that are private firms typically would already have some profit margin built into their contract for services, and a performance incentive may simply be a bonus on top of that. These factors could justify a lower performance incentive percentage than might be received by a utility. Conditions and factors that influence setting incentive levels are reviewed in the Discussion section below.

Rate of Return

Since the New Mexico incentive mechanism is relatively new, we do not have data on amounts that will be paid out. However, since it is not dependent on performance outcomes in the same manner as other states, we can predict that the payments will be 7% of actual energy efficiency spending for all the eligible regulated utilities.

In the Commission Order on case 12-00317-UT, *Final Order Partially Adopting Recommended Decision*, the commission determined the following:

> The financial incentive provided by the EUEA [Efficient Use of Energy Act] is the opportunity for a utility "to earn a profit on cost-effective energy efficiency and load management resource development that, with satisfactory program performance, is financially more attractive to the utility than developing supply-side utility resources." NMSA 1978, § 62-17-5(F) (PNM 2013)

With supply-side generation as the frame of reference, the design and description of the rate-of-return incentive follows naturally. The payment of the incentive to the utility may even be included in base rates similar to investments in supply-side resources. The commission states it plainly, citing and repeating state statute verbatim: "This incentive on energy efficiency resources—also referred to as 'demand-side resources'—may be recovered through an approved tariff rider or in base rates, or by a combination of the two."[13]

Some other states permit utilities to capitalize energy efficiency program costs. The difference is that New Mexico gives utilities the choice to recover incentive dollars through base rates, and that those fund amounts derive from spending, not energy savings. In contrast, Michigan utilities, for example, are allowed to request that energy efficiency program costs be capitalized and earn a normal rate of return, but while they may request a performance incentive for shareholders, it is only if the utilities exceed their annual energy savings targets.

HOW ARE PERFORMANCE INCENTIVES WORKING COMPARED TO FOUR YEARS AGO?

ACEEE's research in 2011 shared three key findings in the areas of state policy, utility performance, and expert opinions on the influence of incentives on utility behavior:

1. The states profiled in the report showed a strong preference for designing policy mechanisms that award incentives based on cost-effective achievement of energy savings targets, rather than other metrics such as program spending levels.
2. Where those targets had been established, utilities consistently met or exceeded target savings levels.
3. Industry experts interviewed agreed that shareholder incentives influence utility behavior and decision making. The report noted some of the industry stakeholder observations in that regard. (Hayes et al. 2011)

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13 "A public utility that undertakes cost-effective energy efficiency and load management programs shall have the option of recovering its prudent and reasonable costs along with commission-approved incentives for demand-side resources and load management programs … through an approved tariff rider or in base rates, or by a combination of the two." NMSA 1978, § 62-17-6(A) (2008) (PNM 2013)

The report also charted the energy efficiency spending per capita for the average of the 18 profiled states, which all had performance incentive mechanisms in effect. That average was plotted relative to other states for four years, 2006 to 2009. As presented in table 5, states with incentives invested more per capita in energy efficiency than states with other policies (such as LRAM or decoupling) and more than those with no supportive regulatory policy. These results do not isolate the impact of other important policy drivers such as EERS. Later in this section we provide additional comparative analysis on states with and without performance incentives on energy efficiency impacts.

Table 5. Average per capita investment in energy efficiency programs by state, 2009 and 2013

2009 utility efficiency spending per capita	
Profiled states with energy efficiency performance incentives in effect (n =18)[1]	$15
Policies other[2]	$8
No mechanisms[3]	$5

2013 electric energy efficiency program spending per capita	
States with electric energy efficiency performance incentives in effect (n=25)	$23.5
States with no incentive policy (all other states)	$15.3

[1] Eighteen states identified in 2011 as having shareholder incentive mechanisms for IOUs active prior to 2009. Many of these states have additional mechanisms in place to align incentives such as decoupling or lost revenue recovery mechanisms. [2] These are the states that have made some effort to align utility incentives to encourage efficiency, excluding the profiled states. This group roughly approximates states that have only adopted decoupling or lost revenue recovery mechanisms for either gas or electric utilities. [3] These are the states that have been identified as having adopted no mechanisms for properly aligning incentives to encourage efficiency.

Developments since 2011 include the following:

- More states have adopted incentives based on cost-effective achievement of energy savings targets, and several have modified or fundamentally changed their mechanisms.
- Regulated utilities and third-party administrators have achieved savings goals and earned incentive payments in all states with incentive mechanisms for which we have current data.
- Industry experts continue to find that performance incentives influence utility behavior and decision making.[14]

Policy Design Trends

Over the past four years, performance incentive mechanisms have been spreading to more states. The trend continues to be for states to adopt mechanisms that incentivize cost-effective achievement of energy savings targets, and to encourage more comprehensive performance criteria. For example, five of the eight states that have authorized performance incentives in the past four years chose either multifactor mechanisms or shared net benefits.

[14] See York et al. 2013 for additional recent examples.

ACEEE's 2011 study found 18 states that had shareholder incentive mechanisms available to investor-owned utilities for at least a full year for which there was information available regarding performance results for the incentives in the field (Hayes et al. 2011). Today, there are 21 states meeting all of those criteria (including determination of incentive amounts and verification of energy savings). There are now 25 states with incentive policies in some phase of implementation and a total of 27 states with at least one authorized incentive mechanism for gas or electric utility energy efficiency.

Relatively recent states to have authorized performance incentives are shown in table 6.

Table 6. States authorizing new performance incentive mechanisms

Type of incentive	State	Year authorized or effective
Multifactor	DC	2011 authorized
Shared net benefits	Arkansas	2010 ordered
	Missouri	2013 effective
	North Carolina	2013 authorized
	South Carolina	2010 authorized
Rate of return	New Mexico	2013 effective
Savings-based	Indiana	2009 12 by utility
	New York	2011 authorized

Three states profiled in 2011, which had incentive mechanisms for individual utilities at that time, no longer have performance incentives in place. Washington had a pilot for Puget Sound Energy, Idaho had a savings-based pilot for Idaho Power,[15] and Nevada had a rate-of-return incentive for NV Energy. Puget Sound Energy did not request a continuation when the pilot expired; since then, the Washington Utilities and Transportation Commission (UTC) issued a package of orders on three different Puget Sound Energy cases including decoupling and others. The Idaho Power pilot was ordered discontinued because of declining returns and energy impacts. The Nevada policy allowed for increased rates for efficiency investments in addition to cost recovery, calculated as the utility's authorized return on equity (ROE) plus 5% applied to the rate-based demand-side management (DSM) costs.

Mississippi and West Virginia have authorized incentives but not yet implemented them. Michigan and Vermont both had (and continue to have) performance incentive mechanisms in place but were not selected to be profiled in our previous report. For detailed information on Michigan and Vermont, please see the case studies in Appendix A.

[15] *Performance-Based Demand-Side Management Incentive Pilot 2007 Performance Update.* Filed with the Idaho Public Utilities Commission March 14, 2008. http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0632/company/20080317PB%20DSM%202007%20UPDATE.PDF

The majority of states that have incentive mechanisms have modified or fundamentally changed them over time. Fourteen states reported having authorized a new version more than a year after the initial incentives were established. A few examples in table 7 illustrate this evolution.

Table 7. Examples of evolving performance incentive mechanisms

State	Past practice	Today
Hawaii	Utility-administered programs Hawaiian Electric Company (HECO) eligible for earning incentives up to 5% of net benefits Received as much $4 million some years, which was over 20% of total program spending	Third-party administrator Multifactor incentive mechanism for public benefits fee administrator (PBFA) Average award 2% of total program spending
Massachusetts	From 2010 to 2012, increased percentage of incentive pool for energy savings, decreased for other metrics Total incentives averaged 8% of program costs	Continuing increase in percentage of incentive pool for energy savings and decrease for other metrics Total incentives now approximately 5% of program costs In 2014, eliminated financial incentives for meeting quantitative performance indicators
Rhode Island	2004 increased electric threshold from 45% to 60% Increased allowed incentive from 4.25% to 4.4% of eligible program costs	2012 increased electric threshold from 60% to 75% 2012 increased allowed incentive to 5%
Texas	2008 electric utilities may earn 1% of net benefits for every 2% they exceed goal with cap 20% total program costs	2011 changed cap to 10% net benefits, greatly increasing potential incentive payments
Wisconsin	For one utility only, same rate of return was earned on efficiency investments as for capital projects	Multifactor incentive for third-party administrator

Increasing Evidence Shows Savings Goals Achieved Where There Are Incentives

ACEEE research findings published in *Energy Efficiency Resource Standards: A New Progress Report on State Experience* (Downs and Cui 2014) identified 18 states with both utility performance incentives and EERS in place. A central finding of the research was that overall, states with EERS were substantially achieving their energy savings goals. One of the lessons learned was that those states hitting their targets also generally had complementary policies in place that supported the utility business model to give the utilities stronger motivation to pursue energy efficiency. These included lost revenue adjustment mechanisms (LRAM), revenue decoupling, and performance incentives such as those examined in this report.

The data we collected strongly point to the conclusion that in those states where there are incentives, utilities in each of them are meeting at least the minimum performance thresholds and earning substantial economic incentives. Of the 25 states with performance incentives being implemented, we obtained complete questionnaire responses for 21. Of those, 18 reported performance incentive amounts paid or to be paid for at least 1 utility in the most recent program period; 17 had at least 1 utility for the most recent 2 program years or cycles. The other three states are still in the midst of their processes—the Wisconsin and Missouri performance incentives, for example, are only calculated at the end of a multiyear cycle. Wisconsin just completed a cycle at the end of 2014, and Missouri will at the end of 2016.

COMPARING EFFICIENCY PERFORMANCE AMONG STATES WITH AND WITHOUT INCENTIVES

From a public policy standpoint, the fundamental purpose of a policy for energy efficiency performance incentives for utilities (or third-party administrators) is to facilitate greater energy efficiency effort and achievements. Data available from ACEEE's annual *State Energy Efficiency Scorecard* research allow us to examine whether having an energy efficiency performance incentive policy in place in a state is associated with greater energy efficiency accomplishments.

For this analysis we focused on two key indicator variables regarding electric energy efficiency performance: energy efficiency spending as a percentage of total revenues, and energy efficiency kWh savings as a percentage of retail sales. We examined the most recent year for which complete data are available, i.e., 2013. We compared states that had an energy efficiency performance incentive policy implemented in 2013 with states that had no energy efficiency incentive policy in place on these average statewide metrics. We also compared subgroups of states, including those with EERS policies and those without EERS policies.

It is important to acknowledge that many unique factors in a state or utility will influence utility behavior regarding energy efficiency programs. Therefore this analysis requires several caveats. First, the year of implementation of an efficiency incentive or EERS policy, for example, may be a significant driver of that state's 2013 efficiency commitments. That variable was not controlled in this analysis and therefore is a limitation. Second, we present statewide averages, whereas sometimes efficiency incentive policies may only be implemented for one major utility. Other unique factors across states include historical experience with efficiency policies, electricity prices, and avoided costs, all of which have an indirect impact on the level of efficiency that is deemed cost effective.

Despite these caveats, it is useful to look at how patterns of performance vary across many states under different policy conditions. The results of our analysis are presented in table 8.

Table 8. Energy efficiency spending and energy savings in states with and without electricity performance incentive policies

	Average 2013 electric EE spending as a percentage of utility revenue	Average 2013 electricity EE savings as a percentage of sales
States with EE performance incentive (n=25)	2.0%	0.9%
States without EE performance incentive (n=25)	1.4%	0.5%

We included states that had incentive policies implemented in 2013. We did not include Mississippi and West Virginia because policies are authorized but not yet implemented.

These results showed that states with incentive policies had somewhat higher spending as a percentage of revenues (2.0%) than states without incentive policies (1.4%); and substantially higher savings (0.9%) than states without incentives (0.5%).

These results are a useful comparison. However they are complicated by the fact that the presence or absence of an EERS policy is such a dominant factor in the level of energy efficiency achieved in a state.[16] We went on to control for that factor by restricting the comparison of incentives to no incentives just to EERS states, and then doing a similar analysis just in states without an EERS. There was virtually no difference between states with or without a performance incentive policy in either of those subgroups.[17]

While these findings are obviously not determinative for every state or utility, (e.g., California's savings dramatically increased following the restoration of incentives in the late 2000s) the results indicate that, in aggregate, having an energy efficiency performance incentive policy appears to be at least somewhat associated with higher levels of energy efficiency effort (program spending) and achievement (energy savings) compared to states without an energy efficiency incentive policy.

Another approach to measuring the effectiveness of efficiency performance incentives is to compare an individual state's progress on efficiency over time after adoption of the policy. To account for the impact of an EERS policy, we could examine states with performance incentives but no EERS, which include Georgia, South Carolina, South Dakota, Kentucky, Missouri, New Hampshire, and Oklahoma. Two of these states, Missouri and Oklahoma, were included in case studies and therefore are good candidates for further examination. For more information and details on Missouri and Oklahoma, see Appendix A.

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[16] See the ACEEE Blog post "IRP vs. EERS: There's one clear winner among state energy efficiency policies." December 16, 2014. http://aceee.org/blog/2014/12/irp-vs-eers-there%E2%80%99s-one-clear-winner-.

[17] By comparison, the EERS subgroup of states combined had three times the level of relative savings (savings as a percentage of sales) as the non-EERS subgroup of states, suggesting a very strong relationship between having an EERS policy and higher levels of energy efficiency spending and savings.

Prior to adoption of an incentive policy, one of Missouri's electric utilities, Ameren Missouri, had a portfolio of customer programs totaling about $70 million over a three-year period (2009–2011). A stipulation and agreement, among Ameren Missouri and parties to its 2012 efficiency plan (2013–2015) application, was approved by the commission in 2012. This agreement included both an incentive and LRAM policy. Ameren Missouri then launched a full portfolio of energy efficiency programs totaling $145 million over the three-year program period, more than twice the levels of the prior three-year plan. The story is similar for Kansas City Power & Light (KCP&L), which had limited energy efficiency programs and associated investment in place prior to establishing its own version of an incentive policy late in 2014. Once in place, KCP&L initiated a portfolio of energy efficiency programs totaling $28.6 million over 18 months; after that time the company is expected to file a full three-year plan. More recently, however, Ameren's proposed level of investment in energy efficiency program remains about the same as the existing three-year MEEIA program plan, but expected savings are about half.

In Oklahoma, the general consensus of stakeholders interviewed by ACEEE is that the incentive policy has been effective in encouraging utilities to achieve greater energy efficiency savings. Since the policy was adopted in 2008, statewide electric utility program energy savings have ramped up quickly from 0 to over 100,000 MWh per year. However some observed the utilities could be achieving much greater savings and would be doing so if the state had an energy efficiency resource standard. Others expressed concern that without the incentive policy in place, it is unlikely the utilities would offer any programs at all. Forthcoming changes will modify several aspects of gas and electric utility efficiency rules, which may have an impact on efficiency savings. For example, beginning in 2015, utilities will only be allowed to collect an incentive if the portfolio achieves 80% or more of the individual utility's goal and the portfolio has a TRC score higher than 1.0.

These state examples provide further evidence that efficiency performance incentive policies have been helpful in making the business case for utilities to invest in efficiency. They also demonstrate some key challenges when the policies are not coupled with specific energy efficiency target requirements. The Ameren example demonstrates large swings in savings from one program cycle to the next. It appears the incentive and LRAM alone were not sufficient to lead Ameren to increase its efficiency savings levels. The structure of the incentive may help by making sure its threshold aligns with a higher percentage of savings. In general, however, without clear and steady policy guidance from the commission through specific targets, energy efficiency as a cost-effective utility resource is vulnerable to large swings in commitments.

From our overall experience, we speculate that an important but less quantifiable effect of a performance incentive policy may be in influencing utility management to cooperate with state policies to require energy efficiency programs (such as an EERS) rather than to seek to block their enactment or challenge them in legal proceedings. If that is the case, that would also be an important function for a performance incentive policy.[18]

[18] Nearly three-quarters of states with an EERS policy also have a performance incentive policy in place.

To further refine this comparison among states with performance incentives for energy efficiency in the electric sector, we reviewed the 2013 *State Scorecard* budgets and energy savings data by type of incentive mechanism.

Table 9. Energy efficiency spending and energy savings in states with various types of incentive policy mechanisms

Type	Average 2013 electric EE spending as percentage of utility revenue	Average 2013 electricity EE savings as percentage of sales
Multifactor (CA, HI, MA, VT, WI)	3.4%	1.6%
Savings-based (CT, IN, MI, NH, NY, RI)	3.2%	1.2%
Share of net benefits (AR, AZ, CO, GA, KY, MN, MO, NC, OH, OK, SC, TX)	1.1%	0.6%
Share of net benefits with EERS or similar policy (AR, AZ, CO, MN, NC, OH, TX)	1.5%	0.8%
Share of net benefits, no EERS or similar policy (GA, KY, MO, OK, SC)	0.6%	0.4%

As shown in table 9, the average energy savings achieved as a percentage of energy sales for those states with performance incentive policies based on a share of net benefits approach are significantly lower than those for states with multifactor and savings-based mechanisms. The same basic difference is observed in terms of the relative level of energy efficiency program spending. This is not surprising, since one would expect the level of programs spending and the level of savings to be highly correlated.

Overall, the results suggest that the relative level of effort for energy efficiency appears to be lower in the group of states with a share of net benefits type of incentive mechanism. One possible explanation of the observed results would be that they may also be heavily influenced by the presence or absence, and the relative level, of EERS policies in the states in the various incentive category groups. As shown in the last two rows of table 9, the existence of an EERS policy continues to appear to be an important factor.

Of those states with shared net benefits performance incentives in place, seven of them have EERS and five do not. Those with EERS have twice the energy savings relative to sales, and more than double the electric energy efficiency budgets as a percentage of utility revenue than the states with no EERS or similar policy. In comparison, 10 of the 11 states listed in table 9 with multifactor and savings-based performance incentives also have EERS or similar policies in place, which may help account for the overall higher performance of those groups.

Discussion

Performance incentive mechanism design and implementation have evolved since ACEEE's 2011 report. The high quantitative correlation between energy efficiency budgets and the presence of performance incentive policies persists. However the correlation does not prove anything conclusive about cause and effect. There are too many factors and confounding variables, including differences across states, to isolate the specific effects of performance incentive mechanisms on energy efficiency budgets and spending without significant additional analysis. Whether or not, and to what extent, it is the performance incentives driving utilities to expand programs and achieve greater cost-effective energy savings, is a research question that we discuss below and through the case studies in appendix A.

Incentives and Utility Behavior

ACEEE concluded in the 2011 report *Carrots for Utilities* that incentives influenced utility behavior, motivated utility management, and influenced energy efficiency planning. Specifically, we found the following:

> Utility industry regulators, staff, and stakeholders consistently indicated that shareholder incentives mechanisms implemented in the 18 Profiled States had influenced utility behavior. Respondents indicated that the ability to assign a dollar value to efficiency investments significantly contributed to "buy-in" by corporate management, making efficiency more appealing as an investment option and engaging senior management in efficiency planning and decision-making in a more significant way. Several utilities indicated that the incentive influenced planning at the utility, allowing treatment of efficiency as a long-term investment strategy (Hayes et al. 2011).

Similarly, in 2013, ACEEE published *Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation* (York et al. 2013). The report considered six utilities that provide large customer energy efficiency programs in states with decoupling or shareholder incentives in effect. The research assessed financial and program impacts as well as organizational and managerial impacts, finding that supportive regulatory mechanisms have been critical in elevating the role of energy efficiency.

To update and expand upon our earlier research, we explored current views on the influence of incentives on utility and program administrator behavior through interviews with regulatory staff, utility program representatives, and nonprofit and environmental group contacts. There is broad consensus among those we interviewed that incentives can have a strong and positive affect on utility program performance. The degree of influence depends on the type and amount of incentive mechanism and how its influence is enhanced or restrained by other regulation, regulatory process and timing, and state policies.

Some interviewees relayed very successful experiences in which performance incentives, and the overall incentive process, directly influenced utility behavior regarding energy efficiency program planning, administration, and even measureable energy savings performance results. This is particularly the case for four leading energy efficiency states in New England. Common among each of these are that they have decoupling or LRAM for both gas and electric, have had performance incentives established for 10 years or longer, and have extensive energy efficiency investment and program portfolios.

Connecticut. Connecticut interviewees saw a correlation between incentives and electric and natural gas savings, as well as a diversification of the source of energy savings, reducing the (narrow) focus on energy savings from efficient lighting. Contacts pointed out that Connecticut officials agreed that performance incentives influence investor-owned utility behavior in a positive way. In particular, the 75% minimum energy savings threshold was not an impediment in any way, and in fact, utilities were "always shooting for the moon" in terms of hitting their energy savings targets.

Massachusetts. Our contacts in Massachusetts noted in particular that the process of negotiating the most recent round of performance incentives was instrumental in gaining utility acceptance of increases to statewide annual energy saving requirements through the EERS. The EERS goals are among the highest in the nation and directly impact savings targets of individual utilities. A utility representative emphasized that the particular design of the incentives in Massachusetts plays a big role in how resources are allocated by utilities, including within energy efficiency portfolios. For a more thorough discussion, see the case study in appendix A.

Rhode Island. Everyone we spoke with regarding Rhode Island was unambiguous in their assessment that the incentives positively influenced utility behavior. National Grid, which serves most of the state, creates projections and program tracking in advance to make sure programs achieve 100% of their targets. The mechanism serves to focus utility attention on achieving their goals. When the incentive structure was changed in 2013 to raise the threshold of savings from 60% to 75% of the energy savings goal, and the slope of the increased incentive levels became much steeper, the utility responded. Now as it gets toward the end of the program year, it assesses savings compared to target and considers pushing to complete some projects that might otherwise lag into the next period. It stays aware of its pipeline of upcoming projects to see if it can work with vendors and distributors to acquire energy savings in those programs and measures where there is strong demand. It also aims for the internal flexibility to move budget money around to promote popular projects, measures, and technologies.

An observer outside of National Grid Rhode Island said the incentives influenced the utility in a very positive way, and described their dedicated program staff as "passionate, innovative, do a good job, and have a program to be proud of. With the implementation of decoupling, it made the utility even more willing to promote energy efficiency." These favorable comments describe the last two years since the changes have been made to the incentive mechanism. Prior to that, those interviewed said the utility had not been on a path to achieving savings goals and had undergone a restructuring and changes to middle management. Subsequent to the changes, they have not had problems achieving savings goals and now regularly achieve more than 100%. For more details, see the Rhode Island case study in Appendix A.

Vermont. Vermont experts we interviewed had consistent views on how performance incentives influenced and sometimes directly guided actions of the program administration contractor, Vermont Energy Investment Corporation (VEIC). VEIC runs the "energy efficiency utility" Efficiency Vermont. One expert observed that "they take seriously and respond strongly to the details of the [performance incentive mechanism] design. They . . . reallocate resources where the incentive structure directs them." In fact, the 2015–2017 period includes more challenging targets on many metrics, because almost all the time in the past all the goals had been met or exceeded, leading to the possible interpretation that "either it is working or the goals were too easy." For a more thorough discussion, see the case study in Appendix A.

New England states are not the only examples of incentives influencing utility behavior. Michigan presents a performance incentives success story from the Midwest. Its incentive mechanism was one of several regulations set forth in 2008 in accordance with the state's energy efficiency standard to support its full implementation. The commission has modified the incentive mechanism to incentivize comprehensiveness in addition to a short-term focus on first-year savings. The incentive attracted utility management support for energy efficiency programs and clearly played a key part in the state's overall performance success: every year since inception of the EERS, Michigan has exceeded energy savings goals.

In other states, those we interviewed had generally positive things to say, along with some caveats, and identified areas for improvement where incentives could be made more effective. In Arizona, incentives were viewed as impacting utility behavior, at least in terms of utility personnel effort. Regulatory staff were reluctant to comment on the overall effect on utility performance, relative to other factors (e.g., the general inclination to want to please the commission.) Other observers said the presence of incentives clearly motivated utility program managers and staff to deliver better performance. It helps internally in the company to see their activity as something that can benefit the company financially.

In a few states, incentives were needed to persuade utilities to accept energy efficiency requirements in the first place, and their subsequent implementation has not been as fine-tuned or closely monitored by regulators as in other states. Oklahoma is an illustrative example. The state had no established energy efficiency programs to begin with, so incentives for efficiency came along with them as part of the package. One observer shared that without the incentives, "programs were nonstarters for the utilities," adding that there is a strong pro-business environment in Oklahoma and that "the incentive rules certainly kept energy efficiency going" there.

Importance of Regulatory Process

California has had performance incentives in place for multiple three-year program cycles, and there is widespread support for some form of incentive. However the implementation in reality has taken longer than originally planned to go through the regulatory processes. Viewpoints from those interviewed about California mechanisms varied quite a bit. Since 2008, incentive amounts have generally not been set out until after the efficiency programs have been implemented. The performance incentive mechanism applicable to the 2010–2012 program cycle was not established until 2012. One stakeholder said that the incentive levels for 2015 had not been laid out yet as of the end of 2014. The delays were due to the uncertainty shareholders had about whether or not the utility would get the incentive payments, and if so, how much and when. One respondent stated that "Wall Street does not see it as income." Another expert explained that all along there had been an expectation of incentives, and that did influence utility behavior and cooperation. The fact that factors related to the program evaluation process delayed the incentive decisions did not change that reality.

The experience of regulators and utilities in Missouri is another example that demonstrates the importance of the process, and in particular, of how impact evaluation plays into it. In Missouri the previous lack of an existing strong, consensus-based evaluation approach has led to a contentious process with different parties' evaluation experts providing differing views on which methods and estimates to use. Policymakers and regulators need to establish such strong evaluation frameworks and protocols that are integrated with the performance incentive mechanisms. Both savings-based incentives and shared net benefits incentives amounts are a direct function of impact evaluations, and whether net, gross, or lifetime energy savings are the basis of the amount matters. Those results, therefore, are critically important for their accuracy and acceptance.

How Should an Incentive Mechanism Be Structured?

Considerations for the effective design of performance incentives include the specific intended functions and purposes of the mechanism as well as the economic, policy, and regulatory context. Incentives are one regulatory tool among several under which utilities do business. The presence or absence of decoupling, LRAM, and EERS can have an impact on the effectiveness of the incentive mechanism in influencing utility behavior and program outcomes. Organizational structures matter, too. Vertically integrated utilities, such as an electric utility that owns electric generating plants, have a different economic and capital expense profile relative to distribution-only electric utilities. A high level of avoided costs can lead to greater net benefits of savings, which in turn could result in higher financial incentive payments, with implications for how high the incentive rate should be and whether there should be an upper limit or ceiling.

One area of priority consideration for designing energy efficiency performance incentives is the core characteristics that make them successful. In a presentation at the 2013 ACEEE National Conference on Energy Efficiency as a Resource, Toben Galvin of Navigant Consulting built upon the objectives set forth by California Public Utilities Commission in its 2013 decision adopting the Energy Savings and Performance Incentive Mechanism, highlighting the following five characteristics:

- Clear performance goals representing a short set of the most critical objectives
- Clarity with respect to how performance will be measured
- A timely and transparent process defined for independent measurement and verification of performance results
- Incentive earnings opportunities sufficient to motivate IOU performance, while providing cost-effective value to ratepayers
- Incentive structure that rewards value and results, not just spending (Galvin 2013)

With both contextual factors and these objectives in mind, another policy design choice for states considering performance incentive mechanisms is what type of mechanism to use. There are pros and cons to each. Examples are presented in table 10.

Table 10. Strengths and weaknesses of various types of performance incentive mechanisms

Type	Strengths	Weaknesses
Shared net benefits	Go further to incentivize by multiplying the financial rewards to the utility for the overall maximization of cost-effective energy savings. Higher financial incentives relative to energy efficiency spending (may also be considered a negative aspect).	Administrator could possibly allocate excessive resources to programs or customer classes with the most cost-effective savings opportunities, which could lead to "cream skimming" or potentially significant inequities among customers. May not promote deeper savings, as those tend to be more expensive and hence have fewer net benefits. May be more uncertainty in the measurements used to determine the award, such as measurement of avoided costs.
Savings-based	Ties dollar incentive amounts directly to energy savings achieved. Rewards effective program performance.	Although all states with energy efficiency programs require some minimum level of cost effectiveness, it may be argued that this approach only encourages meeting the minimum, rather than maximizing cost effectiveness for the energy efficiency portfolios as a whole. May lead to disproportionate investment in programs and technologies with largest energy savings opportunities, such as lighting.
Multifactor	Integrates the incentive mechanism more fully with policy goals beyond the bounds of energy efficiency. Can serve to focus utility and administrator attention on specific, targeted objectives.	Mechanism and process may become complicated to plan, administer, and regulate.
Rate of return	Address the fundamental economic interest of the utility to pursue energy efficiency. Conceptually mimic the basic incentive structure that appears on the supply side. Since energy efficiency program plans generally require commission approval and at least some degree of oversight and reporting, if not stringent measurement and verification of energy savings, rate-of-return mechanisms still may be considered to some degree to be performance incentives, rather than shareholder incentives.	Unless they are carefully structured to require savings performance as an eligibility requirement, they essentially reward spending rather than actual savings performance. Do not provide the same direct and focused motivation to achieve particular performance objectives as much as other options.

For a comprehensive look at designing performance incentives to encourage utility energy efficiency programs, see Whited, Woolf, and Napoleon 2015.

Issues and Potential Solutions

States have used varying approaches to address and mitigate the negative aspects of the incentive types described in table 10. One issue that can arise for any type is excessive focus on short-term savings. This may arise if the incentives are tied to first-year savings results, which is a common metric for program evaluation. The problem is that energy efficiency measure lives vary considerably, but what we really want is persistent, long-term energy savings. Some states have successfully dealt with this by incentivizing lifetime savings rather than first-year, or by including both metrics in the calculation of the incentive amounts.

The misallocation problem noted above for shared net benefits approaches, or the all eggs in one basket issue, could be addressed by regulators through the use of carve outs, requiring savings to be distributed more evenly, and by having a maximum incentive pool or amount for each subset (such as customer groups, geographic regions, or program sectors). Several incentive mechanism policies include elements that require or provide for additional incentive dollars for addressing these concerns. For example, Hawaii rewards inter-island equity. Michigan has potential financial incentives for multi-measure residential and multi-measure commercial and industrial sector performance.

A key concern for policymakers to consider is incentive amount. Incentive levels need to be high enough to motivate utility top management and address the basic economic elements of the regulatory business model, but not so high as to appear too rich and engender political opposition. States with demonstrated performance incentive success with broad support have modified the basic structures—minimum savings threshold requirements, percent incentive amounts (the slope of the increase), and caps—over multiple program cycles in order to reach consensus on a balance of the various goals. Perception is important. When Texas changed the mechanism from 20% of program cost to 10% of net benefits, although the percentage was half as much, the actual payments almost doubled. Texas utilities have been meeting and exceeding both demand and energy savings goals every year since 2008, with only one exception for a single year of energy savings.

Other considerations depend on the type of program administrator. Different approaches may be most appropriate for investor-owned utility, third-party administrator, or nonprofit program administrators. Motivations differ by organization. Investor-owned utilities have multiple financial objectives to advance the overall business interests of the company, including profitability, stock price, managing risk, and their long-term corporate strategy. A third-party administrator is likely to have a narrower concern: the contract must be profitable and achieve a high level of performance that will lead to continuation of the contract. Nonprofit administrators are motivated by financial incentives as well, though in the context of fulfilling their mission rather than only for the money. The purposes and specific objectives of the incentive mechanism also vary. For IOUs, the most basic is to persuade management to legitimately pursue energy efficiency. For third-party administrators, the mechanism may be designed to focus administrator attention on implementing programs to satisfy key performance criteria.

When asked for any suggestions they would make to another state that was thinking of adopting a utility energy efficiency performance incentive such as the mechanisms used in their state, respondents shared the points listed below. A frequent theme was the recommendation to adopt an incentive mechanism that balances motivating utilities and program administrators to achieve energy savings goals with achieving cost effectiveness.

Comments from respondents included the following:

- Keep the mechanism simple while fairly aligning the interests of ratepayers and shareholders.
- Choose a shared-benefits-type incentive that rewards the utility both for achieving higher energy savings levels and for doing so cost effectively.
- Establish clear definitions and a standard that applies to all utilities equally. Standardize the reports, how the savings are calculated and adjusted, and what embedded costs are to be included. Failing to do so may cause confusion and results that vary according to the way they are interpreted.
- Be aware of the size of the incentive. In a structure where the incentive is a function of savings or spending, the total incentive can grow quickly as the energy efficiency budget increases. This is particularly true in the current environment where more and more emphasis is being placed on energy efficiency.
- Inform all parties of what the range of potential incentive levels might be so that no one is surprised. Use incentives to encourage utilities to expand their successes beyond the status quo.
- Consider the potential for interactive effects between programs and the potential for competing priorities when implementing multiple programs with different incentive mechanisms. (This recommendation may be most relevant for multifactor performance incentive mechanisms.)

Conclusions

Over the past four years, performance incentives for utilities and administrators of energy efficiency programs have been playing a vital and growing role in supporting the expansion of energy efficiency. These incentives are a critical component of the package of regulatory policies that address and often overcome disincentives utilities face as part of the traditional regulatory model. As energy efficiency programs multiply and expand in terms of dollars invested and energy savings achieved, more states have enacted and are implementing incentive mechanisms. The supportive regulatory policies go hand-in-glove with higher energy efficiency standards and statewide goals.

States continue to favor those mechanisms that drive program administrators toward the longest-lasting and most cost-effective energy savings performance. This is shown by the number of new states adopting various incentive approaches and by the modifications regulators have been making to existing incentives. Simply rewarding IOUs for spending money on basic energy efficiency programs is only a starting point. Regulators now are aiming for the wisest possible use of ratepayer dollars to achieve maximum net benefits while maintaining equity among customer groups.

Incentive mechanisms are working in combination with other regulatory policies to encourage energy efficiency program performance. Experts agree that performance incentives are needed and that they are effective in influencing utility behavior. In states where they are eligible for financial incentives, utilities meet and frequently exceed energy savings targets.

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Appendix A. Case Studies

ARIZONA

Background

Arizona's entry into the arena of large-scale utility energy efficiency programs is relatively recent, precipitated by orders from the Arizona Corporation Commission (ACC) in 2009 and 2010 that created a utility Energy Efficiency Standard (Docket No. RE-00000C-09-0427, Decision No. 71436 and Decision No. 71819). The commission ordered that by 2020, each investor-owned utility must achieve cumulative annual electricity savings of at least 22% of its retail electric sales in calendar year 2019 through cost-effective energy efficiency programs.

Although Arizona is most noteworthy for that Energy Efficiency Standard, the state has actually allowed utility incentives for energy efficiency programs since 2005. The first approach was adopted in a settlement agreement and was designed as an incentive based on a share of net benefits, with a cap equivalent to 10% of energy efficiency program spending. Later that was modified to a sliding scale cap on program spending (up to 16%). For 2014 that was modified to a flat amount per kWh saved. The structure and timing of these changes varied somewhat for the two major investor-owned electric utilities in Arizona (Arizona Public Service and Tucson Electric Power), which accounts for some of the differences observed in the outcomes table.

Incentive Policy Details

After the policy evolution described above, the current incentive policy for each of the two major utilities is very simple. Once a threshold of 85% of the energy efficiency savings goal is reached, the utility qualifies to receive a cash incentive of $0.0125/kWh times the first-year annual kWh saved. There is no cap on the amount of incentive that could be earned based on that incentive per kWh formula.

Other Relevant Regulatory Features

Arizona currently has an EERS requiring investor-owned electric utilities to achieve cumulative annual electricity savings of at least 22% of its retail electric sales by 2020. The state also requires natural gas utilities to obtain 6% cumulative savings by 2020. Lost revenue recovery mechanisms (LRAMs) were approved for both Arizona Public Service Company (APS) in 2012 and Tucson Electric Power Company (TEP) in 2013. Southwest Gas received authorization for full revenue decoupling in 2011.[19]

Energy Savings Outcomes

Figure A1 illustrates the increase in Arizona electric energy efficiency program savings.

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[19] Analysis of Arizona Public Service data by Lawrence Berkeley National Lab considered the potential impacts of incentives combined with decoupling on utility ROE (Satchwell, Cappers, and Goldman 2011).

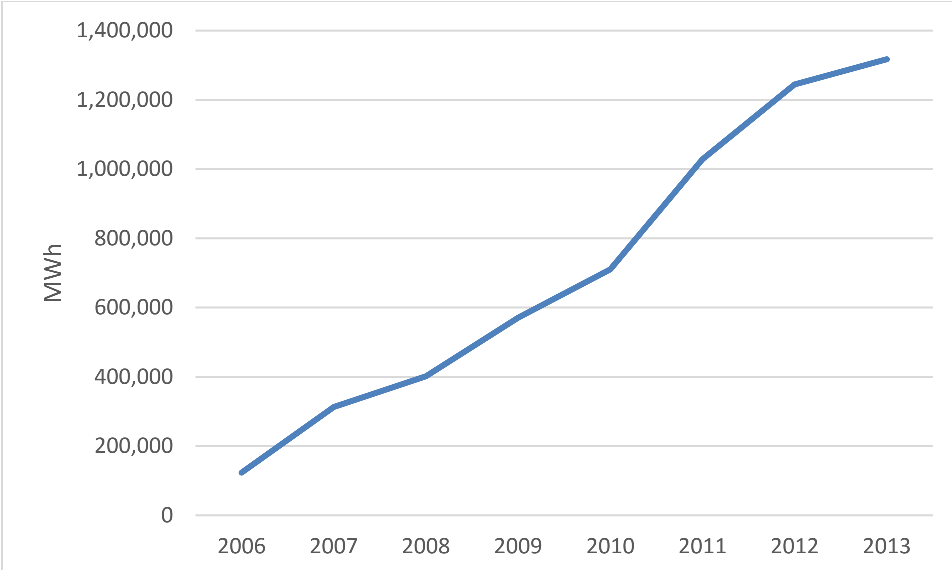

Figure A1. Arizona energy savings 2006–2013. *Source:* ACEEE *State Scorecard* 2007–2014.

Financial Outcomes

Table A1 shows 2012–2013 Arizona performance incentives and savings.

Table A1. Arizona performance incentives and savings 2012–2013

Company	Incentive	Program Cost	Total annual energy savings (MWh)	PI as percentage of program cost
		2013		
Arizona Public Service	$4,529,373	$50,962,754	485,791	8.89%
Tucson Electric Power	$1,879,095	$11,869,205	177,425	15.83%
		2012		
Arizona Public Service	$8,631,364	$61,652,601	551,639	14.00%
Tucson Electric Power	$559,737	$6,224,345	105,655	8.99%

Source: Arizona Corporate Commission

Discussion

The amounts of incentives earned for the most recent two years, under the evolving incentive mechanisms, have been within the mid-range to upper mid-range of typical incentives around the nation (i.e., incentive equivalent to approximately 9–16% of program spending). It is too soon to know how the results of the recently established mechanism ($0.0125/kWh) will compare to those figures.

In general, the basic concept of having some kind of financial incentive for the utility, tied to energy efficiency program performance, has not been particularly controversial. Disagreements have focused on the mechanism and the amounts, rather than the basic principle that the utility could earn an incentive. The most recent change (to move to a flat

$0.0125 per kWh saved) was made because there was some concern that the prior mechanism (capped at a percentage of program spending) might incent the utilities to spend more money than necessary. As noted above, it is too soon to know how the incentive amounts under the new mechanism will compare to the previous approach.

Evaluation

Energy efficiency programs are evaluated by contractors hired by the individual utilities. There is no public process or collaborative oversight of the evaluations, and the ACC does not hold a contested case review of the evaluation process or outcomes. Arizona uses gross savings as the metric for estimating lost revenues.

Looking Forward

There is a docket currently open (Docket No. E-00000XX-13-0214), under which the ACC has a draft proposal that would substantially change the existing utility Energy Efficiency Standard that the ACC created in 2009 and 2010. Depending upon the outcome of this docket, the approach to utility incentives could change. The draft proposal issued by the ACC would eliminate the policy that allows the current incentive mechanism and switch to an approach of allowing the utility to earn a rate of return on energy efficiency program expenditures.

ARKANSAS

Background

Utilities in Arkansas had very little involvement in providing customer energy efficiency programs until 2007, when the Arkansas Public Service Commission (APSC) approved Rules for Conservation and Energy Efficiency Programs requiring electric and gas utilities to propose and administer energy efficiency programs (Docket No. 06-004-R, Orders No. 1, 12, 18). The state's jurisdictional utilities filed Energy Efficiency Plans in July 2007 containing proposed Quick Start efficiency programs. The utility response was still relatively small, and they expressed concern about the adverse financial impact of customer energy efficiency on the utilities. In response, in 2010 the commission took several actions to increase the energy efficiency efforts.

In 2010, the APSC adopted an EERS for both electricity and natural gas, guidelines for efficiency program cost recovery, and a shareholder performance incentive. The EERS targets set by the commission were moderate, rising from an annual reduction of 0.25% of total electric kWh sales in 2011, to 0.5% in 2012, and 0.75% in 2013. In 2013 the APSC extended the 0.75% target to 2014 and then set a target of 0.9% for 2015. The PSC deferred the ruling on 2016-2017 targets pending completion of a thorough potential study aimed at improving programs.

In December 2010 the Arkansas PSC approved a joint electric and gas utility motion to allow the awarding of lost contributions to fixed costs that result from future utility energy efficiency programs. All investor-owned utilities are approved to recover lost revenues as part of the annual energy efficiency program tariff docket (Order No. 14 Docket 08-137-U). In 2007 the APSC approved a decoupling mechanism for the three major natural gas distribution companies in the state, but no decoupling has been approved for electric utilities.

In December 2010 the APSC issued an Order approving a general policy under which the commission outlined steps to approve incentives to reward achievement in the delivery of essential energy conservation services by investor-owned utilities (Order No. 15 Docket 08-137-U). Incentives were approved for all three gas utilities in the state and the two largest electric utilities in 2012 and 2013.

Incentive Policy Details

The APSC announced the general policy for utility performance incentives for energy efficiency achievements in December 2010. The basic mechanism approved is a share of net benefits approach. A utility must first meet 80% of the energy savings target for a given year to qualify for incentives. If the annual savings are between 80% and 100% of the target, the utility can receive an amount equivalent to 10% of the net benefits, capped at 5% of the program spending amount. For savings above 100% of target, the 10% of net benefits is capped at 7% of program spending. Any incentive awards are rolled into the single energy efficiency charge to customers, along with LRAM adjustments and program costs. There are no penalties, although the commission has reserved the right to issue penalties for nonperformance.

As with the LRAM mechanism, incentives are calculated based on net savings. One distinction is that under the LRAM policy, lost revenue compensation is done contemporaneously based on projected savings, and then trued up with evaluation, measurement, and verification (EM&V), whereas incentive awards are not approved until the EM&V documentation is in hand. The process involves the utility’s filing an annual report, followed by a contested case process and then a commission order.

Other Relevant Regulatory Features

Arkansas has had an EERS in place since 2010 for both gas and electric utilities. The energy savings targets are established by the Arkansas Public Service Commission in three-year cycles. The three largest natural gas distribution companies in Arkansas are decoupled, while no electric companies are decoupled in Arkansas. Electric utilities in Arkansas are able to collect lost revenues associated with declining sales resulting from energy efficiency programs, as well as earn an incentive based on energy efficiency savings results. Note that the commission issued an order inviting electric utilities to file decoupling but none has done so.

Energy Savings Outcomes

Figure A2 illustrates the increase in Arkansas electric energy efficiency program savings.

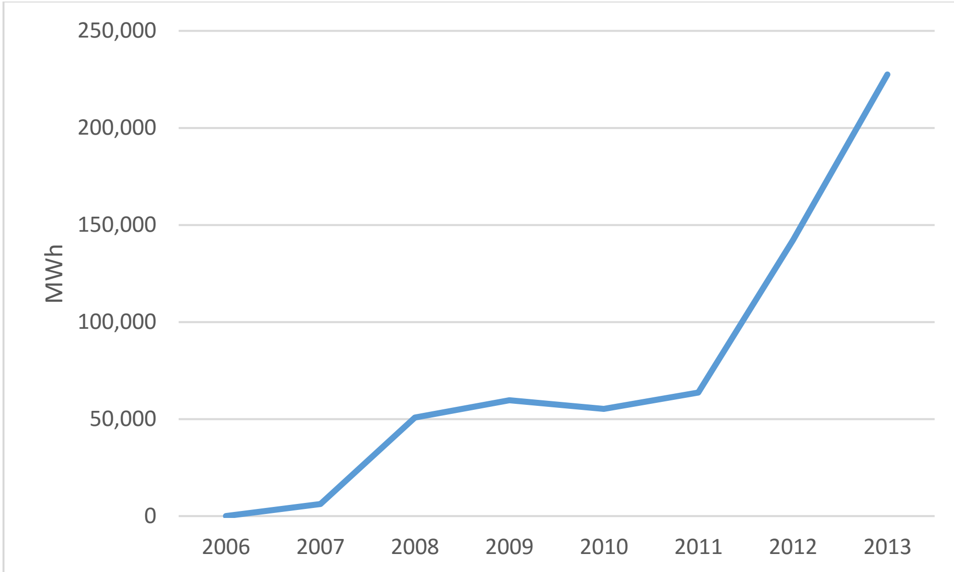

Figure A2. Arkansas energy efficiency program savings 2006–2013. *Source:* ACEEE *State Scorecard* 2007–2014.

Financial Outcomes

Table A2 shows 2012–2013 Arkansas performance incentives and savings.

Table A2. Arkansas electric utility performance incentives 2012-2013

Company	Incentive	Program cost	Total annual energy savings (MWh)	PI as percentage of program cost
		2013		
Entergy Arkansas	$3,712,268	$52,285,262	188,468	7.10%
SWEPCo	$574,225	$6,803,249	25,387	8.44%
		2012		
Entergy Arkansas	$1,743,700	$28,515,019	107,627	6.12%
SWEPCo	$413,131	$5,289,095	17,767	7.81%

Source: Arkansas Public Service Commission

Discussion

The major electric utilities in Arkansas have definitely ramped up their energy efficiency efforts and achievements in response to the various commission orders and policies that have been established since 2007. How much of that might be attributable to the incentive policy is difficult to say.

In aggregate, it does appear that the package of policies adopted in 2010 (i.e., EERS, LRAM, and performance incentives) have had a very notable effect. In the words of a commission staff person: “The commission took away every excuse, and the utilities have found it’s not so bad.” Whereas there has been some discomfort with the LRAM policy by the commission and other parties, the concept of having a shareholder incentive tied to good performance has not been particularly controversial for most parties.

Evaluation

The evaluation process is overseen by the APSC. The commission requires each utility to hire its own independent EM&V contractor to perform evaluations, and to jointly fund an Independent EM&V Monitor that provides overall oversight and guidance, and operates under the direction of the commission staff. The commission established an EM&V collaborative called Parties Working Collaboratively (PWC) to develop a technical resource manual that is updated annually and approved by the commission. Arkansas uses net savings as its evaluation metric.

Looking Forward

The incentive structure has been slightly modified to take effect for the next three-year planning cycle. Within a range of 80—120% of savings target, the 10% net benefits will be capped at a sliding scale of 4—8% of program spending. The new system will provide somewhat lower rewards for performance at the low end of the scale, and somewhat higher rewards for performance at the upper end of the scale.[20] Other aspects are expected to remain the same. Looking ahead in general, there will be substantial turnover of Commissioners during 2015, so there is understandably some uncertainty about future decisions.

CALIFORNIA

Background

California has had a long history with performance incentives for utility energy efficiency programs spanning three decades. We focus on the more recent history here that provides the most relevant context for the current issues.[21] Since 2006, there have been, broadly speaking, three main versions of incentives over this time period.

The first was the Risk Reward Incentive Mechanism (RRIM), which was in place for the energy efficiency program cycle from 2006 to 2008 and continued for the bridge year, 2009. RRIM applied to all the investor-owned gas and electric utilities: Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison, and Southern California Gas. Under the RRIM, the utilities would be eligible to earn an incentive payment of up to 12% of the net benefits of their energy efficiency programs if they achieved 100% of targeted energy savings. If they achieved between 85% and 100% of the savings goal, the highest incentive payment would be 9% of the net benefits. For the range between 65% and 85% of target, no incentives would be available. Below 65%, utilities could end up paying a financial penalty

[20] A similar adjustment, to a steeper slope to the incentives for higher savings relative to targets, has been done in Rhode Island with apparently favorable results. See the Rhode Island case study for more details.

[21] The state had incentives for utility energy efficiency from 1990 to 2001, with modifications every four-year program cycle, including performance incentives of varying percentages and amounts that were in place from 1990 to 1997. From 1998 to 2001, there were milestone-based incentives. From 2002 to 2005, following deregulation and the electricity crisis, there were no performance incentives.

of 5 cents per kWh, 45 cents per therm and $25 per kW for each unit below the savings goal (Gold 2014). These thresholds were referred to as earnings cliffs.

Expectations for energy efficiency program performance were high at this time, with the California Public Utilities Commission (CPUC) predicting an estimated $2.7 billion in net ratepayer benefits (resource savings minus investment costs)[22] from the 2006–2008 program cycle. The statewide incentives ceiling, or maximum incentive funding available, was $450 million, or $150 million per year. This represented the low end of comparable supply-side earnings and was below the average percentage of net benefits awarded through national shared savings mechanisms, but some found it controversial that the potential incentive payments were that high.[23] The mechanism as a whole was found by the CPUC to require improvements to make the earnings process more transparent, streamlined, and less controversial while still achieving the CPUC's policy goals.[24] Ultimately, near the end of the program cycle, the CPUC changed the mechanism to be a "flat" 7% of net benefits. This was at least in part to streamline the overall process and remove the "earnings cliffs".

The second period lasted from 2010 to 2012. The CPUC described this as a reform of the RRIM, though it was substantially different. During this period, the mechanism in place was a "management fee" of 5% of energy efficiency program spending, with the potential for an additional 1%, based on how well savings were calculated. This era was still dynamic, if not as contentious as the period leading up to it. Not only were the amounts established, again, toward the end of the program cycle, in November of 2012, but so was the mechanism itself.

The third recent evolution of performance incentives began with the Efficiency Savings Performance Incentive (ESPI). ESPI applied to energy efficiency programs beginning in 2013. The primary stakeholders had been part of the process for previous performance incentives as well. In general, the investor-owned utilities supported the mechanisms and the ESPI in particular, with some supporting it very strongly. The Natural Resources Defense Council (NRDC) was another stakeholder involved in the process. NRDC supported robust and effective policies to support energy efficiency programs, including well-designed utility performance incentive mechanisms. Other organizations engaged in the process through filing comments or other means included the Division of Ratepayer Advocates (DRA) and the Utility Reform Network (TURN). DRA and TURN consistently opposed the performance incentives, but TURN ultimately did not oppose the ESPI incentive mechanism itself.[25]

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[22] CPUC (California Public Utilities Commission). 2007. Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs. Decision 07-09-043. Rulemaking 06-04-010.

[23] For comparison with California supply-side, see CPUC's "Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs." http://www.cpuc.ca.gov/NR/rdonlyres/33471B66-CCCB-4999-B727-CB02CBAB8734/0/D0709043.pdf.

[24] For specifics about the areas of the mechanism that were not working as intended, and proposed remedies, see "White Paper on Proposed Energy Efficiency Risk-Reward Incentive Mechanism and Evaluation, Measurement, and Verification Activities," CPUC Energy Division, April 1, 2009.

[25] See TURN comments filed with CPUC dated July 16, 2012, on RRIM reform and April 26, 2013, on ESPI feedback.

When the ESPI was adopted by the CPUC in September 2013, it was designed to incorporate four fundamental objectives. These principles both addressed lessons learned from experience with prior incentive mechanisms and struck a relative balance or consensus among the priorities among major stakeholders. The CPUC asserted that "an effective incentive mechanism should incorporate:

> (1) Clear performance goals;
> (2) A clear understanding of how performance will be measured in relation to those goals;
> (3) A timely and transparent process for independent measurement and verification of performance results; and
> (4) Incentive earnings opportunities sufficient to motivate IOU performance, while providing cost-effective value to ratepayers."[26]

The relative values placed on these attributes is apparent in the structure of the ESPI, described below.

Incentive Policy Details

The ESPI is a multifactor incentive. It is predominantly an energy savings-based incentive mechanism that also features management fees for non-resource efforts (see explanation below) and codes and standards programs. Specifically, there are four paths for utilities to earn financial incentives:

1. *Lifecycle savings performance award*. Potential earnings are based on the programs' energy lifecycle savings achievements. Lifecycle energy savings include the kWh or therm energy savings over the full lives of the installed energy efficiency measures. This is a fundamentally different approach than the traditional first-year savings, which in comparison leads to a shorter-term focus. This breaks out to 85% for electric program performance (kWh and kW) and 15% for natural gas (therms). Within the electric, the potential award is weighted two-thirds for kWh (energy) savings and one-third for kW (demand) reductions. The maximum incentive for the savings component is 9% of total resource program spending.[27]

2. *Ex ante review and compliance*. This component awards earnings for demonstrated compliance with CPUC-set calculation standards. Ex ante are forward-looking energy savings estimates, in contrast to ex post, which are arrived at by conducting EM&V after the programs have been implemented, with the intent to estimate actual gross and net

[26] CPUC (California Public Utilities Commission). 2013. Order Instituting Rulemaking to Reform the Commission's Energy Efficiency Risk/Reward Incentive Mechanism. Decision Adopting Efficiency Savings and Performance Incentive Mechanism. Decision 13-09-023 Rulemaking 12-01-005

[27] "Resource programs" are what we traditionally think of as utility energy efficiency programs: those energy efficiency programs that aim to directly save energy. "Non-resource" programs, including energy efficiency research, education-only, or market transformation programs, have other primary purposes in addition to energy efficiency savings.

savings. Three percent of resource program spending, less certain administrative expenses such as EM&V, is the upper limit for this component.

3. *Non-resource management fee.* Earnings are a factor of the non-resource program spending levels for the utility. Non-resource programs include education, training, pilot programs, and new technologies. Three percent of non-resource program budget is the upper limit for this component. The fee is calculated as 3% of non-resource expenditures by utility, less administrative spending, as verified by commission audit reports.

4. *Codes and standards management fee*. This fee provides an earning opportunity for the utility based on the amount of codes and standards (C&S) program budget spent, capped at 12% of that budget. The fee is calculated as 12% of C&S spending by utility, less administrative costs.[28]

The largest of these four is the lifecycle savings performance award, which comprises 73% of the total dollar amount. The earnings amount is calculated in three steps. First, utilities must determine the ceiling, or maximum possible incentive. This is 9% of the total (statewide) resource program budget, less administrative costs. Second, utilities calculate what the dollar amount of the maximum award will be on a per-unit, lifecycle basis. This is done by multiplying the statewide first-year savings goal (such as the GWh goal) by the estimated portfolio average useful life of energy efficiency measures (for example, 12 years), and then adjusting the result by the portfolio average net-to-gross ratio and dividing the maximum possible incentive by the number of units, such as GWh. After actual energy savings achievements have been quantified, the third step is to multiply the amount of savings by the incentive award amount per unit. If, for example, the EE programs achieve 75% of that utility's savings goal, they will earn 75% of the maximum incentive.

There is no minimum savings threshold for the ESPI. The more savings, the better, in a linear progression toward the ceiling level, determined by the budget.

Other Relevant Regulatory Features

Performance incentives are one regulatory tool among many state policies that work together supporting gas and electric energy efficiency programs. While overall this is a reflection of commitment to energy efficiency achievements to meet public policy goals, it does make it difficult to isolate with much precision the specific impacts of the various performance incentive mechanisms on energy savings performance over time.

California has for many years had the largest and most extensive energy efficiency programs in the country, which is a direct result of its policy framework. In addition to performance incentive mechanisms, strong utility goals, and decoupling, California state

[28] For the language describing these calculations as ordered by CPUC, see Decision 13-09-023 *Decision Adopting Efficiency Savings and Performance Incentive Mechanism*

laws and regulations mandate the acquisition of all cost-effective energy resources, ahead of all supply-side resources.[29]

The energy savings goals are a particularly important part of the package of policies encouraging strong utility energy efficiency program performance.[30] The CPUC established electric and natural gas goals in 2008 for years 2012 through 2020, aiming for 16,300 GWh of gross electric savings over the nine-year period (see CPUC Decision 08-07-047). (For 2010–2012 energy efficiency portfolios, see Decision 09-09-047.) More recent targets under the ESPI are included in the approved 2013–2014 program portfolios and budgets for the state's IOUs. The targets call for gross electricity savings of almost 4,000 GWh and natural gas savings of approximately 94 MMTh for those two years (see CPUC Decision 12-11-015).

All the major investor-owned utilities have had decoupling in place since 2004. As with performance incentives, California has been implementing decoupling in various forms for decades. See more in the ACEEE state policy database.

California Performance Incentive Outcomes

During the 2006–2014 period (including the RRIM, the modified RRIM, and the ESPI), California utilities have generally been increasing electric energy efficiency program budgets (see figure A3). Utilities also achieved higher levels of energy savings in 2012 compared to 2006. However, their savings results showed more fluctuation from year to year.

[29] Assembly Bill 1890 (1996) http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_bill_960924_chaptered.html and Assembly Bill 995 (2000) http://www.energy.ca.gov/renewables/documents/ab995_bill_20000930_chap.html

30 For a history of the CPUC goal setting process by utility through 2010, see http://www.cpuc.ca.gov/NR/rdonlyres/E1E38C4A-5E56-4ACB-B0C9-AFD69656BFA0/0/goalsdecisionssummary.pdf.

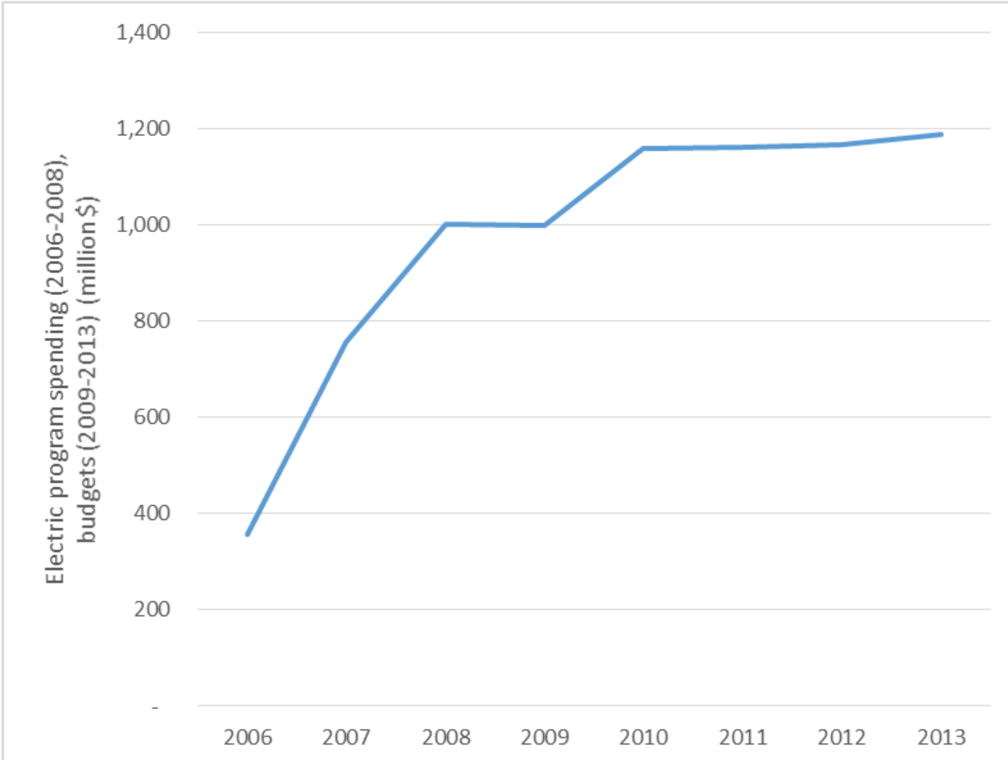

Figure A3. California electric program spending (2006–2008) and budgets (2009–2013). *Source:* ACEEE *State Scorecard* 2007–2013.

Figure A4 illustrates the increase in California electric energy efficiency program savings.

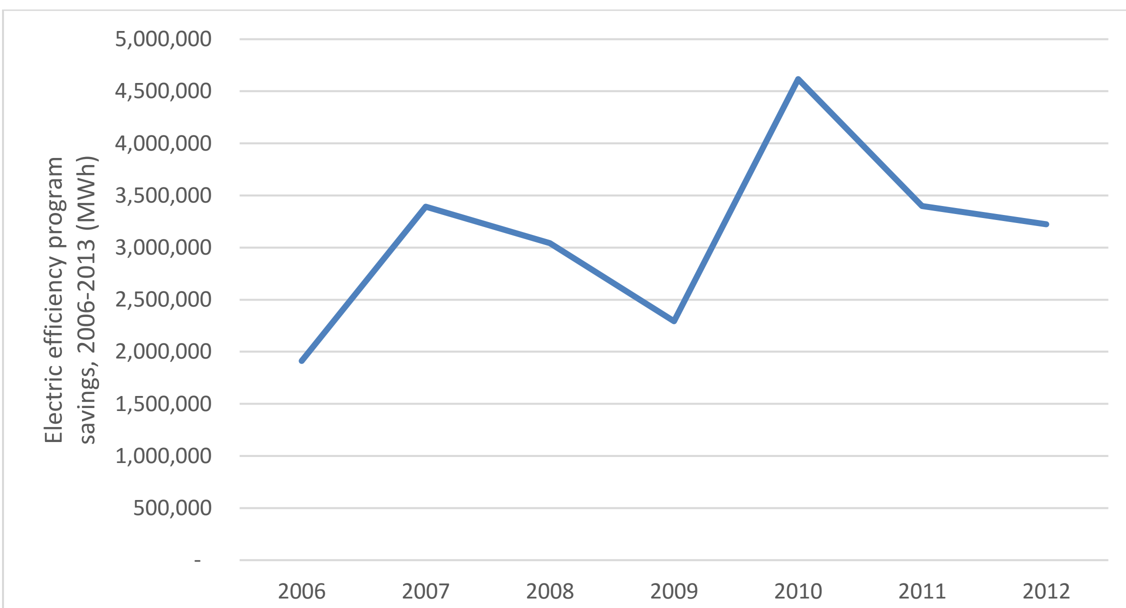

Figure A4. California energy savings 2006–2012. *Source: ACEEE State Scorecard* 2007–2013. Savings from *State Scorecard* are net incremental annual savings from Energy Information Administration Form 861 supplemented with addition data. Some year-to-year variation may be due to in part to net savings calculations methodologies and reporting. For additional data, see California Energy Statistics Portal, http://eestats.cpuc.ca.gov/Views/EEDataPortal.aspx.

Table A3. California energy savings results and performance incentive awards

Actual earnings/award (million $)	DSM total cost (million $)	Energy saved (annual)	Award as percentage of cost
Disbursed actual, 2010: 42.2	2010–2012: 2,508	2010–2012 (gross reported): 9,167 GWh, 155 MMTh 2010–2012 (net evaluated): 4,923 GWh, 94 MMTh	Actual, 2010: 6% 2010-2012, based on policy: 6%
2008 (first progress payment): 82.2 2009 (second progress payment): 61.5 2010 (final installment): 29	2006–2008: 1,929	2006–2008 (reported using ex-ante values): 9,999 GWh, 140 MMTh 2006–2008 (CPUC staff estimate based on evaluation reports): 4,097 GWh, 44 MMTh.	2006–2008: 9%

Sources: CPUC Decision 12-12-032 December 20, 2012. Alternate Decision Approving 2010-2012 Energy Efficiency Incentive Mechanism and Disbursing 2010 Incentive Awards; California Energy Statistics Portal; http://eestats.cpuc.ca.gov/Views/EEDataPortal.aspx ; CPUC staff estimate; Hayes et al. 2011.

Discussion

As a percentage of total energy efficiency spending, performance incentive award amounts for California utilities have ranged approximately from 5% to 9% during the 2006–2014 period. This is in the middle range relative to what other states' performance incentives were averaging during the latter half of this period.

To place these amounts in the context of the evolution of incentives in California, three considerations should be noted. First, the RRIM (2006–2008) started as a shared net benefits mechanism. If it had functioned as originally designed, it is reasonable to expect that actual incentive payments would have provided a substantially higher rate of earnings on EE than what happened. Second, during the 2010–2012 cycle, the amounts were calculated predominantly based on spending, which, compared to a shared net benefits approach, reduces performance risk for the utilities and therefore lower awards may be justified from that perspective. Third, the shift to the ESPI not only represents potential for increasing the incentive payments relative to EE budgets, but also the opportunity for improved regulatory certainty through greater clarity of goals, energy savings measurement, and processes. These improvements will fulfill the CPUC's criteria for an effective mechanism presented in the background section of this case study.

Those we interviewed emphasized the importance of clarity and timeliness in the process leading to EE performance incentive earnings in order for the mechanism to have the optimal, and intended, impacts on utility behavior. In particular they noted that the delays in setting out performance incentives after the efficiency programs have been run has had an adverse effect. Other than the first RRIM for the 2006–2008 program cycle, the mechanism has not been implemented on time. One observer explained that "the [incentive] dollars are not as valuable as if the mechanism and clear expectations were in place on time."

There was support for the ESPI and the current direction of the process. The 2013–2014 mechanism aligns with other CPUC policies to support long-term savings, giving IOUs more opportunity to optimize their energy efficiency portfolio to achieve the greatest returns. Another observer noted that for the utility role in supporting C&S, their investment returns 12% guaranteed, which is attractive. The incentive mechanism is viewed by some on the utility side as helping them to focus on their demand-side management efforts.

Program Evaluation and Regulatory Process

An energy efficiency expert in California summed up how the history of energy savings estimation has figured into performance incentive amounts, saying, "There have been challenges in California in terms of looking at ex ante and ex post savings values and the uncertainty that created for the utilities." There have been a variety of specific concerns over the years leading to conflicts and protracted non-resolution, a full discussion of which is beyond the scope of this case study. One of the many related issues has been how the energy savings that form the basis of the performance incentives should be counted.[31]

Looking Forward

Among those we interviewed in California, their outlook on the design and functioning of the ESPI is positive, considering it to be win-win approach. The CPUC has granted an extension to the Energy Division for complying with the schedule contained in the ESPI for when earnings awards shall be approved. While this is due to the process for evaluation contractors to be hired, get the needed data from the IOUs, and complete their work related to ex post savings—an important determinant of earnings award amounts—the extension is for 90 days only. This is a substantial improvement over the pace of past proceedings as discussed above.

Another shift that is cause for optimism is the move to rolling portfolios and evergreen programs. These create a longer-term framework for energy efficiency program planning. Energy efficiency funding was granted for 2015 and will continue unless changed for 10 years. The traditional program-year- or program-cycle-based approach, in comparison, leaves decision makers—at the utilities, program implementers, contractors, and trade allies—with an incentive to make decisions based on the short term. In conjunction with a predominantly lifecycle-savings-based performance incentive that contributes to utility earnings, the current mix of supportive regulatory policies addresses multiple concerns that impact energy efficiency performance.

INDIANA

Background

Indiana was one of the first states to enact a Certificate of Convenience and Public Necessity statute, back in 1983, requiring utilities to demonstrate need before constructing or

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[31] Under the RRIM, the combination of sharp financial penalties for failure to achieve at least 65% of the energy savings goal, with differing estimates of net savings, can make the difference between millions in penalties or millions of dollars in awards. This was the case with PG&E. For a case study of how these two elements influenced California regulation, see Gold 2014.

purchasing new generation facilities. In 1995, Indiana adopted an Integrated Resource Planning (IRP) rule (170 IAC 4-7), requiring electric utilities to develop an IRP that evaluated demand-side and supply-side resources on a comparable basis.

In spite of that framework, the fact that Indiana utilities were achieving very little energy efficiency savings led to a series of hearings and investigations by the Indiana Utility Regulatory Commission (IURC) beginning in 2004, culminating in a landmark order in 2009 (Cause 42693, December 9, 2009). The order established a two-part approach, with utilities contracting with a single independent third-party administrator for a basic set of statewide programs (core programs), and utilities individually administering additional energy efficiency programs (Core Plus programs) in their own service territories, to address aspects not covered by the Core programs. The order also established an EERS, requiring utilities to meet annual savings goals. The goals began at 0.3% of annual sales in 2010, increasing to 1.1% in 2014, and leveling off at 2.0% in 2019.

With regard to the issue of utility performance incentives for energy efficiency, Indiana had actually established a performance incentive rule in 1995 (170 IAC 4-8-6) as part of its guidelines for DSM cost recovery. However, as noted above, very little DSM was taking place. Now, subsequent to the 2009 order, four out of the five major electric utilities (Indiana Michigan Power [I&M], Indianapolis Power and Light [IPL], Vectren Indiana, and Duke Energy Indiana) have approved mechanisms. (Per the IURC 2009 order, utilities are eligible to apply for shareholder incentives relating to their Core Plus programs.) Table A5 provides summary data for three of the utilities.

In March 2014 the Indiana legislature voted (SB 340) to end many of the aspects of the IURC 2009 order, effectively eliminating both the Core program requirement and the annual savings goals that had been established by the IURC. Governor Mike Pence neither signed nor vetoed the bill, and it became law in April 2014. While the legislation did not alter the state's policy regarding utility incentives for energy efficiency, the entire framework for utility energy efficiency programs in Indiana is somewhat uncertain at this point.

Policy Details

In the first phase of incentives after the 2009 order, three utilities (IPL, Vectren, and Duke) originally had similar tiered-savings mechanisms, where the incentive is calculated as a percentage of program costs, and the percentage to apply is determined by the level of savings achieved relative to the savings goal for that year. There is also the potential for a penalty, if savings achieved are less than 50% of the goal. Vectren subsequently had its incentive modified to a share of net benefits approach (see description below), and Duke's tiered structure has been updated per settlement agreement included in an order issued under 43955 DSM-2. Duke now has additional constraints such as a higher floor, no penalty, a lower ceiling, and an overall cap on incentive earnings. We provide the most recent incentive structure for Duke Energy as an example in table A4.

Table A4. Duke incentive structure

Percentage of annual kWh target achieved	Incentive as percentage of EE program cost
0–74.99%	0%
75–79.99%	6%
80–89.99%	8%
90–99.99%	10%
100–109.99%	12%
≥ 110%	12.13%

Source: Cause No. 43955 DSM 02 Final Order

Savings for these tiered-savings mechanisms are calculated on a gross-savings basis.

For more details, see the most recent orders for each utility addressing the mechanism (IPL; Cause No. 44497; Vectren: Cause No. 44495; Duke: Cause No. 43955).

Two utilities (I&M and Vectren) now have an incentive mechanism designed as a share of net benefits. The mechanism calculates net benefits using the utility-cost approach (i.e., total utility EE program costs compared to utility system benefits in the form of avoided capacity and energy costs). The incentive that may be earned is capped at an amount equivalent to a certain percentage of program costs (Vectren 10%, I&M 15%). For those utilities with authority to receive an incentive, all must achieve some minimum percentage level of the savings goal in order to qualify for an incentive.

For more details on the I&M mechanism, see Cause No. 44486, December 3, 2014.

To illustrate the results of these mechanisms, the table provides the energy savings and incentive results for the most recent two years for two largest tiered-savings utilities and one share of net benefits utility.

Other Relevant Regulatory Features

Indiana previously had an EERS in place, but this policy was eliminated by the 2014 Indiana General Assembly. Four of the five largest IOUs in Indiana currently collect lost margins for sales lost because of efficiency programs. The fifth utility, Indianapolis Power and Light, is awaiting a commission order to recover lost margin. There are no electric companies in Indiana with decoupled rates. However, of the three largest natural gas distribution companies operating in the states, two of them have decoupled rates for most rate classes. Finally, Indiana offers companies the opportunity to participate in a voluntary renewable portfolio standard to earn a higher return on equity for rate base facilities. Energy efficiency savings are one means of a company meeting the voluntary standard. However no company has formally requested commission approval to participate in the standard.

Energy Savings Outcomes

Figure A5 illustrates the increase in Indiana's electric energy efficiency program savings.

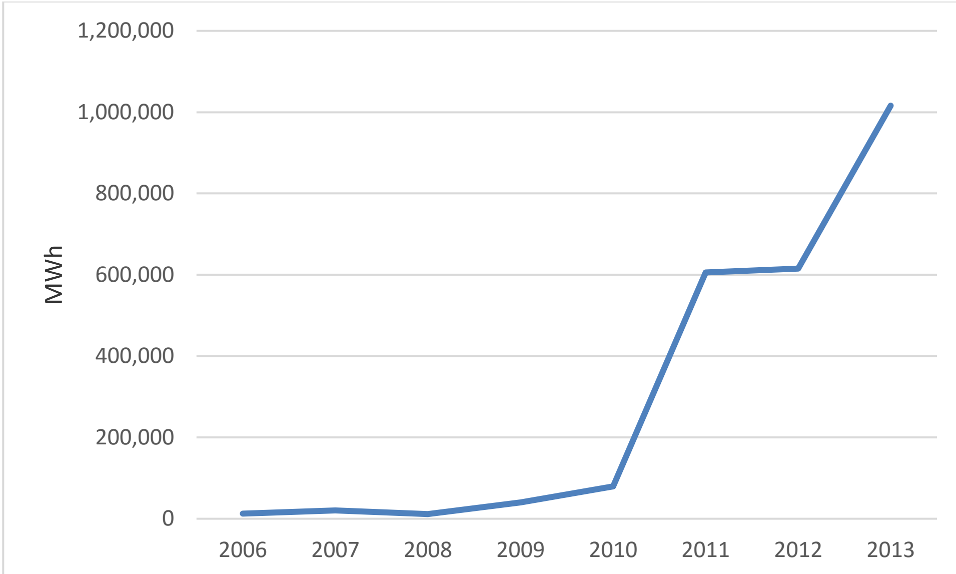

Figure A5. Indiana's energy savings 2006–2013. *Source:* ACEEE *State Scorecard* 2007–2014.

Financial Outcomes

Table A5 shows utility incentives and program costs.

Table A5. Utility energy efficiency program cost and performance incentive amounts

Company	Incentive	Program cost	Total annual energy savings (MWh)	PI as percentage of program cost
		2013		
Duke Energy	$981,232	$9,035,050	78,472	10.86%
Indianapolis Power and Light	$463,760	$5,797,000	43,902	8.00%
Indiana Michigan Power	$826,646	$8,336,021	21,981	9.92%
		2012		
Duke Energy	$757,080	$5,047,198	51,288	15.00%
Indianapolis Power and Light	$362,640	$6,521,640	18,572	5.56%
Indiana Michigan Power	$0	$949,178	3,311	0.00%

Source: Indiana Utility Regulatory Commission

Discussion

As noted above, Indiana had established the possibility of utility performance incentives (as well as lost revenue recovery) in 1995, in connection with its integrated resource planning rule and guidelines for DSM cost recovery (170 IAC 4-8-6). The utility response in terms of energy efficiency programs prior to the 2009 IURC order was very minimal and deficient in many respects (e.g., lacking evaluation plans and protocols). Therefore there was little impetus to move forward with things like performance incentives and LRAM.

Consequently, a key objective in approving the shareholder incentives mechanisms in 2009 and 2010 was to support achievement of the energy efficiency goals established in the 2009 order. The results have been fairly successful. Three out of the five utilities met their targets for 2012. Four out of five met them for 2013, and all but one met their cumulative targets for the three-year time frame 2011–2013. In the opinion of staff interviewed, the incentives did significantly affect utility behavior—in terms of both utility energy efficiency budgets and savings—but this was particularly in the context of the 2009 order requiring energy efficiency programs. In the words of one staff member,

> The primary thing that affected utility behavior is that DSM was no longer voluntary with the issuance of the 2009 order. It was mandatory. It was structured. It had compliance deadlines and oversight boards. At that point the LRAM and incentives became a huge focus for utilities.

From the Indiana experience, an overarching observation is that the existence of a policy allowing performance incentives (and also lost revenue recovery) was apparently not sufficient to generate meaningful utility energy efficiency programs in the decade preceding the 2009 IURC order. In the opinion of both Staff and advocate organizations, the key factor was the 2009 order creating the annual energy savings requirements (i.e., essentially an EERS).

It remains to be seen how utility performance will fare now that the annual savings requirement has been terminated. At this point the Indiana utilities have all filed and had approved one-year plans to continue some energy efficiency programs during 2015. Early indications suggest that while programs will continue, they will deliver lower savings than in previous years.

Evaluation

For the Core Plus programs, the programs for which a performance incentive is possible, each individual utility is responsible for hiring an independent evaluator to evaluate its programs. Although there is no formal central oversight process such as there was with the DSM Coordinating Committee for the statewide Core programs, each utility has an oversight committee with, at a minimum, representatives from the OUCC, and most also have participation from other stakeholders. The committees are involved in reviewing the work and reports prepared by the evaluator.

For the utilities using the simple tiered-incentive approach described earlier, gross savings are used as the indicator of program impact. For the utilities using a share of net benefits approach, savings are determined using net savings (i.e., adjusted for free-riders).

Process

The experience with the performance incentive mechanisms is fairly limited thus far, and it is too soon to draw conclusions about the process. Staff felt that as utilities utilize and incorporate program evaluation results into the calculations the utilities use to determine their requested incentives, important experience will be gained and the process improved. The OUCC is theoretically in a position to audit the process utilities use and their reported numbers, although the limited time and resources available to the OUCC limits their ability to audit. This need is partially offset by the participation of the OUCC in the utility-specific oversight boards.

Looking Forward

Interestingly, all three utilities that originally had a tiered incentive structure have requested a shared net benefits approach, such as the structure used for I&M. More broadly, however, the policy landscape for utility energy efficiency in Indiana is fairly uncertain at this point. In the governor's letter to the legislature after the enactment of SB 340 he stated,

> I have requested the Indiana Utility Regulatory Commission to immediately begin to develop recommendations that can inform a new legislative framework for consideration during the 2015 session of the Indiana General Assembly.

This suggests that the entire framework for utility energy efficiency programs in Indiana is up for revision. It is yet to be determined whether there will be any type of utility energy efficiency requirements at all (much less annual savings targets), and what associated policies (e.g., LRAM, decoupling, performance incentives) will remain or will be put in place.

At this point the Indiana utilities have all filed one-year plans to continue some energy efficiency programs during 2015. It is noteworthy that now that the IURC annual savings targets have been struck down by SB 340, the projected savings from the voluntary utility plans are, in aggregate, about half of what would have been required under the previous IURC standard.

MASSACHUSETTS

Background

Performance incentives for energy efficiency have existed in Massachusetts for electric companies since the early 1990s. The current performance incentive policy was established in the Green Communities Act of 2008. The act required gas and electric companies to file energy efficiency investment plans with the Department of Public Utilities (DPU). The three-year plans required detailed acquisition strategies for all cost-effective energy efficiency. The plans also were to include a proposal for a mechanism to recover a performance incentive based on meeting or exceeding goals proposed in the plan.[32] There have been two cycles of three-year plans filed since the enactment of the Green Communities Act. The first plan laid the foundation for a performance incentive based on DPU precedent and guidelines included in the Green Communities Act of 2008.

The first three-year plan was filed in 2009 for program years 2010 through 2012. The performance incentive mechanism approved with this plan was made up of three components: a savings mechanism, a value mechanism, and a performance metric mechanism. Both the savings and value mechanism incentive payments are based on benefits for the energy efficiency programs. The savings mechanism focused on total benefits, while the value mechanism focused on net benefits. The payout rate for both

[32] Green Communities Act 2008. Sec 21 (b)(2)

incentives is applied uniformly across all program administrators including investor-owned utilities (PAs) and determines the incentive amount a PA can receive for each dollar of benefit achieved through the implementation of a program.[33] The payout rates were calculated based on projected benefits and a statewide available incentive pool of $65 million. The allocation of the incentive pool to individual PAs is based on the PA contribution to the statewide savings goals.

The performance metric incentive created both overall targets and targets for specific customer sectors. An incentive amount was allocated for individual PAs after meeting targets specific to each metric. The DPU required PAs to demonstrate annually how each metric was fulfilled. Some metrics, such as CoolSmart: Increase Percent of Correct Installations were easy to quantify.[34] Others, such as the MassSAVE/Weatherization: Increase Direct Installation (DI) bulb penetration, were more difficult to quantify. For the metrics that were more difficult to quantify, the DPU required PAs to make a showing on how necessary steps were taken to meet the specific goal.

Table A6 shows the features and details of the three components of the incentive mechanism.

Table A6. Massachusetts performance incentive structure 2010–2012 three-year plan

Component	Percentage of incentive pool	Purpose	Threshold/limit	Calculation of incentive
Savings mechanism	2010: 45% 2011: 50% 2012: 52%	Encourage maximum total benefits	75% of MWh goal, no limit	Payout equal to percentage of the statewide incentive pool allocated to the savings mechanism divided by the projected statewide benefits multiplied by actual benefits
Value mechanism	35%	Encourage maximum net benefits and cost-effectiveness	75% of MWh goal, no limit	Same as savings mechanism, but instead of total benefits, net benefits are used
Performance metrics	2010: 20% 2011: 15% 2012: 13%	Encourage benefits not included in value and savings mechanism	75% – Threshold 100% – Design 125% – Exemplary	Varies by metric

* Performance metric incentive specifics were approved in Orders in DPU 09-116B through DPU 09-118B and DPU 09-120 through DPU 09-127B. *Source:* DPU 09-116 through DPU 120 January 28, 2010 Order.

[33] Order on DPU 09-116 through DPU 09-120.

[34] This performance metric required electric utilities to increase the percentage of quality installs and properly sized installs in homes that receive a CoolSmart rebate. The goal is based on the increase in percentage over the baseline.

The most recent performance incentive mechanism was approved for the 2013 through 2015 three-year plans.[35] There were several changes in the performance incentive mechanism from the 2010 through 2012 three-year plan. The total statewide performance incentive pool is $80,056,269 for electric program administrators and $16,002,485 for gas. This was an increase in the electric pool and a decrease in the gas pool. Instead of a 75% threshold for PAs to earn the savings and value incentives, each PA has a different energy savings threshold required to begin earning a performance incentive. For example, Unitil Electric must meet 76.72% of its goals before earning an incentive, while Columbia Gas only needs to meet 70.78%. The allocation of the incentive pool also changed. Instead of an annual change in the savings mechanism and performance metric allocation of the pool, fixed percentages were used for all three years. These allocations are listed below under the policy details section. Finally, the performance metric goals were updated and some metrics were eliminated.

Other Relevant Regulatory Features

The Massachusetts Green Communities Act of 2008 requires electric and gas utilities to obtain all cost-effective energy efficiency. Three-year goals are established in triennial plans filed by electric and gas utilities. Electric and gas utilities in Massachusetts have also been fully decoupled since 2008.

Policy Details

Currently, the structure of the incentive mechanism for the 2013–2015 three-year program plans includes two components: the savings and value mechanisms. The performance incentive for each utility is the sum of these two components. The calculation of the savings component payout is the adjusted statewide incentive pool divided by the projected dollar value of statewide benefits. The calculation produces a payout rate per dollar of total benefits. The payout rate for the value mechanism is determined in the same manner except net benefits are used instead of total benefits.

The approved incentive pool available for the 2013–2015 period is $80,056,269 for electric program administrators and $16,002,485 for gas. This pool is equal to approximately 5% of the statewide electric budgets and 3% of the statewide gas program budget. The allocation of the statewide incentive pool is as follows: 61.5% to savings mechanism and 38.5% to value mechanism. The thresholds for both savings and value mechanisms, shown in table A7, vary by utility.

Table A7. Massachusetts performance incentive savings and thresholds by utility 2013–2015

Program administrator	Threshold (%)
Unitil (electric)	76.72
Berkshire Gas	76.72
NEGC	76.72

[35] *See* Massachusetts Three Year Efficiency Plans Order DPU 12-100 through DPU 12-111. 1/31/13.

Program administrator	Threshold (%)
Unitil (gas)	76.72
NSTAR Electric	76.32
NSTAR Gas	76.25
National Grid (electric)	75.65
National Grid (gas)	75.16
WMECo	72.46
Columbia Gas	70.78

Source: Massachusetts Three-Year Efficiency Plans Order DPU 12-100 through DPU 12-111, 1/31/13

Outcomes

Table A8 shows program costs, energy savings, and incentives for electric and gas. companies.

Table A8. Massachusetts statewide energy efficiency program cost and performance incentives, 2003–2013

Year	Program cost	Energy savings	Performance incentive	Percentage of program costs
		Electric (MWh)		
2003	$107,980,774	317,571	$8,313,920	7.70%
2004	$122,694,191	442,164	$9,625,058	7.84%
2005	$113,875,666	454,726	$9,607,335	8.44%
2006	$120,352,651	417,031	$10,128,897	8.42%
2007	$110,976,339	489,622	$9,181,020	8.27%
2008	$115,103,427	388,254	$9,281,413	8.06%
2009	$175,526,256	424,617	$12,904,615	7.35%
2010	$221,090,179	603,460	$17,577,689	7.95%
2011	$254,692,915	765,226	$20,478,218	8.04%
2012	$361,392,739	950,887	$24,145,526	6.68%
2013*	$466,748,563	1,026,520	$27,379,880	5.87%
		Gas (MMBtu)		
2010	$62,657,153	1,123,915	$4,075,030	6.50%
2011	$97,247,817	1,518,116	$4,213,081	4.33%
2012	$135,120,261	2,262,716	$5,165,768	3.82%
2013*	$171,403,031	2,466,798	$5,413,645	3.16%

* 2013 data not yet approved. *Source:* DPU.

The data show a consistent recovery of approximately 8% of program cost as a performance incentive since 2003. Performance incentives paid have declined in recent years as the total amount available for performance incentives has declined relative to program costs. The total dollar amounts of incentives have still been increasing and are projected to continue to increase as program costs continue to increase. While the performance incentive pool has been limited to approximately 5% of total program cost since 2010 for electric utilities, program administrators are able to earn additional incentives for exceeding planned total benefits, net benefits, and performance metric goals. This is the reason the percentage of program costs has exceeded 5% since 2010. Overall, program administrators in Massachusetts have been exceeding planned performance goals to earn performance incentives greater than 5% of program cost.

Discussion

Massachusetts' newest performance incentive structure is still being refined after going through two approval processes in 2009 and 2012. The consensus of the stakeholders interviewed by ACEEE staff for this report is that performance incentives have been successful in encouraging higher levels of performance. This may be due to the combined effect of multiple policies creating an overall environment that addresses disincentives and pulls for higher savings: all cost-effective energy efficiency, decoupling, savings goals, high program budgets, etc. The performance incentive mechanism is designed to incentivize program administrators to meet savings goals in the most cost-effective manner. The performance metric mechanism is designed to achieve other policy objectives for specific programs. The debate in Massachusetts regarding the performance incentive has focused on the total incentive pool, not the existence or nonexistence of an incentive.

Looking Forward

Currently, Massachusetts is in the middle of a three-year energy efficiency plan cycle. New three-year plans for 2016 through 2018 will be filed next year. Within those plans, it is likely program administrators and other stakeholders will file requested changes to existing performance incentives. However Massachusetts operates some of the most successful utility-sponsored programs in the country. Major changes to the incentive structure or elimination of incentives entirely is not expected in the near future.

MICHIGAN

Background

Michigan had a history of fairly aggressive energy efficiency programs until 1995, when energy efficiency programs and integrated resource planning were discontinued during the move toward electric restructuring. Michigan had essentially no utility-sector energy efficiency programs from 1996 until 2008.

Public Act 295 of 2008 (enrolled SB 213) brought energy efficiency programs back to Michigan in the form of an EERS that requires all electric utilities and all natural gas utilities to file energy optimization (efficiency) programs with the Michigan Public Service Commission (MPSC). Public Act 295 offers multiple options for utilities for energy efficiency program administration, including administration by the utility itself, or through an independent administrator selected by the MPSC. In practice, the largest utilities in the state have chosen to administer their own energy efficiency programs.

PA 295 established an EERS with annual savings requirements for electric utilities of 0.3% in 2009, 0.5% in 2010, 0.75% in 2011, and 1.0% per year for 2012 through 2015 and each year thereafter. For natural gas utilities, the EERS savings was 0.1% in 2009, 0.25% in 2010, 0.5% in 2011, and 0.75% per year for 2012 through 2015 and each year thereafter. Spending for each utility was capped at 0.75% of total retail revenues in 2009, 1.0% in 2010, 1.5% in 2011, and 2.0% in 2012 and each year thereafter.

PA 295 (2008) contains two provisions whereby utilities can receive an economic incentives for implementing energy efficiency programs. First, they are allowed to request that energy efficiency program costs be capitalized and earn a normal rate of return. Second, they are allowed to request a performance incentive for shareholders if the utilities exceed the annual energy savings target. Performance incentives cannot exceed 15% of the total cost of the energy efficiency programs, or 25% of net benefits, whichever is less.

Act 295 also authorized natural gas decoupling, which has been implemented in a series of commission orders. The MPSC subsequently approved decoupling proposals for electric utilities Consumers Energy and Detroit Edison (U-15768 and U-15751), but commission decoupling orders for electric utilities were overturned in court on the basis of lack of specific statutory authority. (See Michigan Court of Appeals *Association of Businesses Advocating Tariff Equity v. Michigan Public Service Commission*, April 10, 2012). In light of the court's determination, the commission dismissed all pending cases involving electric revenue decoupling.

Incentive Policy Details

The utility energy efficiency performance incentive mechanism in Michigan has evolved somewhat over time. Initially it was a fairly simple sliding scale of incentive (defined in terms of percentages of energy efficiency program spending), tied to meeting or exceeding the energy savings annual target. The maximum incentive that could be earned was an amount equivalent to 15% of program spending or 25% of net benefits, whichever was smaller.

The current mechanism is a performance-based incentive with multiple criteria (one of which is still the amount of savings relative to the goal, but others include things like meeting minimum levels of low-income customer participation, the percentage of participating customers that install multiple measures, etc.). The current mechanism for the two largest utilities was established in 2012 and implemented for program year 2013.

The amount of incentive is still capped at the statutory level (15% of spending or 25% of net benefits). Additional threshold requirements are an overall portfolio benefit-cost ratio (using the Utility System Resource Cost Test, i.e., a utility cost test) of 1.25, and meeting 100% of the annual energy savings goal. There are no penalties in the incentive mechanism. Savings are determined using net savings.

Other Relevant Regulatory Features

Michigan adopted an EERS in 2008 with the passage of the Clean, Renewable, and Efficient Energy Act (PA 295). The EERS has both electric and gas savings targets that increase annually. The Michigan Public Service Commission previously approved decoupling for the state's two largest investor-owned electric utilities, Consumers Energy and DTE Energy, but the ruling was overturned by the state appellate court. Natural gas companies in Michigan have implemented a decoupled rate structure as natural gas distribution companies were not affected by the appellate ruling overturning electric decoupling.

Energy Savings Outcomes

Figure A6 illustrates the increase in Michigan electric energy efficiency program savings.

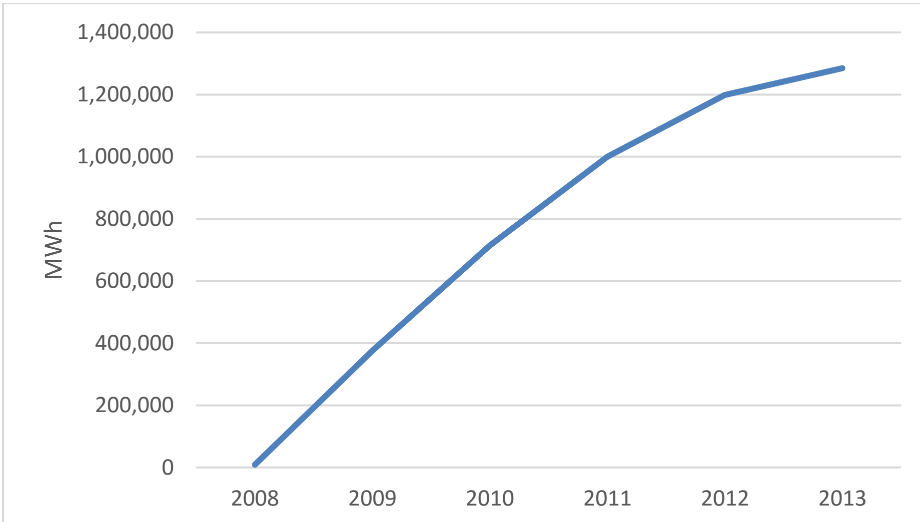

Figure A6. Michigan energy efficiency savings 2008–2013. *Source:* ACEEE *State Scorecard* 2009–2014.

Financial Outcomes

Table A9 shows 2012-2013 Michigan performance incentives and savings.

Table A9. Michigan energy efficiency performance incentives and savings, 2012–2013

Company	Incentive	Fuel	Program cost	Total annual energy savings	PI as percentage of program cost
2013					
Consumers Energy	$17,530,000	Gas	$47,776,949	2,173,124 MCF	15.00%
		Electric	$69,097,040	473,045 MWh	
DTE Energy	$15,085,266	Gas	$25,600,000	1,436,000 MCF	15.00%
		Electric	$74,900,000	614,000 MWH	
2012					
Consumers Energy	$17,327,620	Gas	$48,148,786	2,378,978 MCF	15.00%
		Electric	$67,369,007	409,353 MWh	
DTE Energy	$14,732,686	Gas	$28,600,000	1,186,000 MCF	15.00%
		Electric	$69,600,000	611,000 MWH	

Source: Michigan Public Service Commission

Discussion

The regulatory package established in Michigan in 2008 through PA 295 appears to have worked very well. Michigan utilities went from essentially no-customer energy efficiency programs prior to the legislation, to meeting and exceeding the EERS savings goals every year since the legislation. By all accounts the existence of the utility performance incentive has been a major factor in securing utility management support for the energy efficiency programs. As shown in table A9, the major utilities have generally succeeded in earning the maximum incentive each year.

One concern that has been identified is the tendency for EERS goals established in terms of annual savings to motivate the use of quick, short-term savings measures and programs rather than more comprehensive and longer-term measures. That is one reason the MPSC staff modified the incentive mechanism structure to include elements of comprehensiveness, and not just first-year annual savings.

Evaluation

Utilities are responsible for hiring independent evaluation consultants to evaluate their programs. For key assumptions and technical inputs, the evaluators must use the technical reference manual that is established and overseen by the MPSC through a multiparty energy optimization collaborative process. Utilities submit evaluation results and incentive claims that are reviewed and decided upon in a contested-case process.

Michigan uses net savings for determining any incentive awards.

Looking Forward

Michigan's legislation (PA 295) called for a review of the utility energy efficiency policy in 2015. By all accounts, the policy has been very successful to date, so one might not expect major changes. Two areas for improvement that have been discussed are eliminating the spending cap on energy efficiency programs (currently 2% of utility revenues) and clarifying that electric utilities are eligible for decoupling.

MINNESOTA

Background

Minnesota has a long history of utility energy efficiency programs, dating back well over two decades. In the mid-1990s, Minnesota tried out an LRAM policy, but the cumulative amounts of lost revenue recovery over time became excessive and controversial. The LRAM policy was ended in 1999, and the state shifted to a shareholder incentive approach. Minnesota has maintained substantial utility energy efficiency programs throughout that time period to the present.

In 2007, the Minnesota Legislature passed the Next Generation Energy Act of 2007 (Minnesota Statutes 2008 § 216B.241). Among its provisions is an EERS that sets energy-saving goals for utilities of 1.5% of retail sales each year. This act also directed the Public Utilities Commission to allow one or more rate-regulated utilities to participate in a pilot program (of up to three years) to assess the merits of a rate-decoupling strategy. Although no decoupling mechanism had yet been adopted for an electric utility as of February, 2015, two gas utilities do have decoupling in place. The commission continues to examine decoupling and has established criteria and standards to be used when considering proposals from utilities. A decoupling proposal for Xcel is before the commission.

Minnesota has had a shared benefit incentive mechanism in place since 1999. The details have been modified at various times. The current version is described below. Also, Minnesota's regulated utilities are required to file integrated resource plans with the Public Utilities Commission.

Policy Details

Minnesota's utility performance incentive for energy efficiency is based on a shared net benefits approach. The most recent version was approved on December 12, 2012. The incentive mechanism starts at a threshold of energy savings achieved equal to the lesser of 0.4% of retail sales or 50% of an average of the last five years' achievement levels. As energy savings levels increase to 1.5% of retail sales, utilities are awarded an increasing share of net benefits created. The mechanism is calibrated so that when electric utilities achieve energy savings approximating 1.5% of retail sales, the utility is rewarded with an incentive equal to an average of 7 cents per first year kWh saved. The amount of the incentive varies with the actual cost effectiveness of the implemented projects. There are two caps on the amount of incentives: the average incentive may not exceed 8.75 cents per first year kWh and may not exceed 20% of net benefits. That is the case for Xcel Energy, Interstate Power and Light, and Otter Tail Power. For Minnesota Power, the caps are 8.75 cents per first year kWh and 30% of net benefits.

Incentive payments are based on gross savings. There is no penalty component to the mechanism.

Natural gas utilities have a very similar incentive mechanism, except that the incentive structure is calibrated around a 1% annual savings target, instead of the 1.5% for electric utilities.

Other Relevant Regulatory Features

In 2007, the Minnesota legislature passed an EERS setting savings targets for electric and gas utilities. Minnesota does not allow electric companies to collect lost revenue associated with energy efficiency but has approved decoupling for two natural gas distribution companies, Minnesota Energy Resources Corporation and Center Point Energy.

Energy Savings Outcomes

Figure A7 illustrates the increase in Minnesota electric energy efficiency program savings.

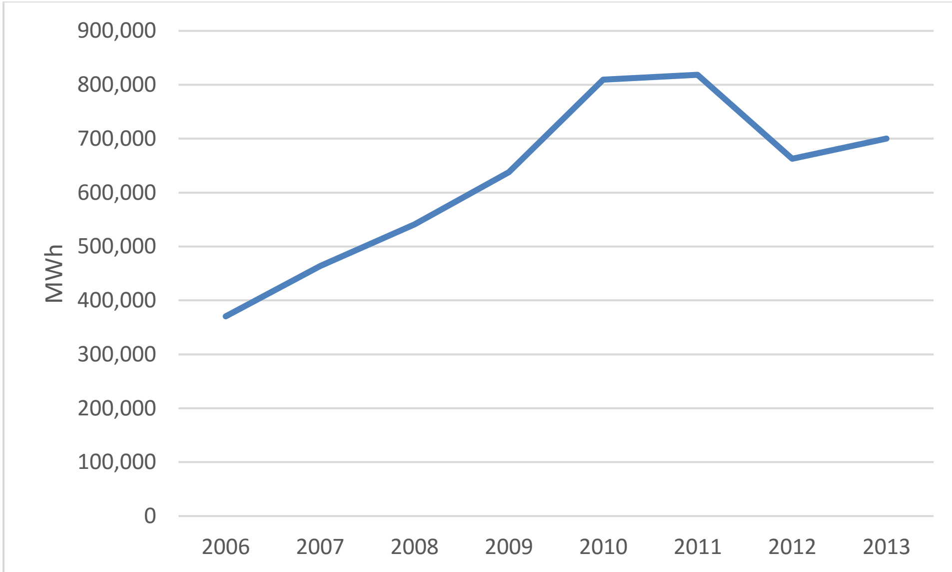

Figure A7. Minnesota energy efficiency savings 2006–2013. *Source:* ACEEE *State Scorecard* 2007–2014

Outcomes

Table A10 shows 2011–2012 Minnesota performance incentives and savings.

Table A10. Minnesota gas and electric energy efficiency program cost, savings, and performance incentives, 2011–2012

Company	Incentive	Program cost	Total annual energy savings	PI as percentage of program cost
		2012		
Xcel Electric	$53,911,925	$87,071,903	533,478 MWh	61.92%
Otter Tail Power	$2,681,575	$4,816,994	30,794 MWh	55.67%
Center Point Energy	$3,207,411	$19,226,405	13,664 Dth	16.68%
Xcel Gas	$2,682,879	$13,040,587	7,671 Dth	20.57%
		2011		
Xcel Electric	$52,004,975	$76,302,262	465,444 MWh	68.16%
Otter Tail Power	$2,608,094	$4,344,581	27,958 MWh	60.03%
Center Point Energy	$4,950,392	$18,990,010	15,284 Dth	26.07%
Xcel Gas	$2,833,202	$11,359,730	7,471 Dth	24.94%

Source: Minnesota Public Service Commission

Discussion

Minnesota's current utility performance incentive approach may well be providing the highest level of energy efficiency performance incentives as a percentage of program costs in the nation. As shown in table A10, over the most recent two years for which data are available, the incentives have been equivalent to well over half to as much as two-thirds of program costs for the electric utilities. This has been a source of concern for many parties, including the attorney general, industrial customer representatives, and the staff of the Minnesota Department of Commerce.

It should be noted that Minnesota's electric utilities had neither LRAM nor decoupling mechanisms in place during this time period. In the absence of a decoupling mechanism, it is possible that the performance incentive may have functioned in part as a way to mitigate utility concerns about the impact of energy efficiency on the recovery of its authorized revenue requirement. Natural gas utilities do have decoupling, and their incentive amounts relative to program spending are much lower. Nevertheless, the question has been raised as to whether that high level of incentive is really necessary to sustain a high level of electric energy efficiency program effort.

Evaluation

Energy savings for prescriptive rebates are based on energy savings found in the Minnesota Technical Reference Manual and customized savings algorithms approved by the Department of Commerce as part of a utility's DSM plan.[36] A measurement and verification protocol exists for larger projects, including billing analysis and submetering.

Utilities analyze their programs using the above protocols and submit the results to the commission in a docket to claim the incentive. Other parties can weigh in on the calculation of the incentive and the timing. The commission then issues an order for an approved incentive amount, and these amounts are rolled into the energy efficiency charge to customers (along with program costs).

Looking Forward

The largest electric utility in the state, Xcel Energy, has a pending proposal to adopt decoupling, and that may change the dynamics around the amount of performance incentive allowed. Also, the Department of Commerce is conducting a review and is due to release a report in July 2015, to include recommendations on these issues.

MISSOURI

Major legislation was enacted in 2009 that marked a major turning point for utility energy efficiency programs in Missouri. The Missouri Energy Efficiency Investment Act (MEEIA, SB 376), passed and signed into law in 2009, established a regulatory framework for utility energy efficiency programs to value demand-side investments equal to traditional investments in supply and delivery infrastructure. Prior to passage of MEEIA, Missouri had limited energy efficiency programs for utility customers even though utilities were required to file and implement electric utility integrated resource plans.

Key provisions of MEEIA specifically address the utility business model. Under MEEIA the Public Service Commission is to

[36] http://mn.gov/commerce/energy/topics/conservation/Design-Resources/Technical-Reference-Manual.jsp.

- provide timely cost recovery for utilities
- ensure that utility financial incentives are aligned with helping customers use energy more efficiently
- provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings

MEEIA opened the door for electric utilities to propose and establish demand-side program investment cost-recovery mechanisms (DSIM) for demand-side management energy efficiency programs. Addressing the utility business model was critical for Missouri's utilities to move ahead with such programs. One of Missouri's utilities, in fact, had established a fairly large portfolio of programs at the time MEEIA was enacted. Ameren Missouri had launched a portfolio of customer programs totaling about $70 million over a three-year period (2009–2011). However the company rolled back this level of program spending and associated activity when efforts to establish cost recovery and incentive mechanisms meeting the above objectives were not approved in the company's 2011 general rate case. When the commission and utility reached an agreement that established a DSIM, the impact was significant. The stipulation and agreement was between Ameren Missouri and parties to its 2012 MEEIA (2013–2015 plan) application; the agreement was approved by the commission on August 12, 2012. Ameren soon launched a full portfolio of energy efficiency programs totaling $145 million over the three-year program period.

The story is similar for Kansas City Power & Light (KCP&L), which had limited energy efficiency programs and associated investment prior to establishing its own version of a DSIM late in 2014. Once in place KCP&L initiated a portfolio of energy efficiency programs totaling $28.6 million over 18 months, after which time the company is expected to implement a full three-year plan. KCP&L Greater Missouri Operations (GMO), a utility-operating company owned by the same corporation as KCP&L and that serves an area surrounding Kansas City, has followed a similar path as KCP&L. GMO had in place a small set of programs prior to establishing a DSIM; with this in place the company is proceeding with a greatly expanded set of programs.

Other Relevant Regulatory Features

The DSIMs in place for Missouri's utilities contain provisions both for recovery of programs' costs and lost revenues resulting from the programs and the opportunity for incentive awards. The incentive mechanisms are based on receiving a percentage of net shared benefits as determined by deemed savings for lost revenues recovery and by program evaluations for incentive awards. MEEIA's provisions supporting energy efficiency are not mandatory. MEEIA enables utilities to propose and implement such programs but does not require them. The specific language from the statute is the following:

> The Commission shall permit electric corporations to implement Commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings.

Decoupling requires periodic adjustments to true up rates and allowed revenues; these adjustments are viewed as rate-making outside of general rate cases. Some parties believe Missouri's existing statutes could be interpreted so as to allow decoupling. To date there have been no decoupling proposals associated with DSM programs submitted to or considered by the commission.

Policy Details

The basic structure of the demand-side incentive mechanisms (DSIMs) established for Ameren MO, KCP&L, and GMO is the same, but details differ.

Ameren Missouri's DSIM was established by a unanimous stipulation and agreement resolving Ameren Missouri's MEEIA Filing (Case No. E0-2012-142) among Ameren Missouri, the staff of the Missouri Public Service Commission, the Office of Public Counsel, the Missouri Department of Natural Resources, the Natural Resources Defense Council, Sierra Club, Renew Missouri (Earth Island Institute), the Missouri Industrial Energy Consumers, and Barnes-Jewish Hospital. The DSIM agreed to by these parties and approved by the Commission addresses program cost recovery, net shared benefits relating to the throughput disincentive, and net shared benefits relating to the performance incentive. The provision addressing net shared benefits relating to the performance incentive is structured this way:

- After the conclusion of the three-year MEEIA plan period and using final EM&V results, Ameren Missouri will be allowed to recover the performance incentive, which is a percentage of net shared benefits (NSB) according to the graduated or sliding scale (shown in the schedule below). The cumulative annual net megawatt-hours determined through EM&V to have been saved as a result of the MEEIA programs will be used to determine the amount of the performance incentive. The sliding scale established determines the amount of the performance incentive award amount for the three-year MEEIA plan.
- The savings metric used to determine the performance incentive is equal to the cumulative net MWh savings determined through EM&V divided by Ameren Missouri's total targeted 793,100 MWh, which is the cumulative annual net MWh savings in the third year of the three-year MEEIA Plan period.
- The targeted net energy savings are adjusted annually for full program-year impacts on targeted net energy savings caused by actual opt-out.
- Actual net energy savings for each program year are determined through the EM&V, including full retrospective application of net-to-gross ratios at the program level using EM&V results from each of the three program years. The sum of these three program years' annual net energy savings is used to determine the amount of the performance incentive award, following the schedule presented in table A11 and figures A8 and A9.

Table A11. Ameren Missouri performance incentive schedule

% of MWh target	Three-year total ($MM)	% of net benefits*
<70	$0.00	0.00%
70	$12.00	4.60%
80	$14.25	4.78%
90	$16.50	4.92%
100	$18.75	5.03%
110	$22.50	5.49%
120	$26.25	5.87%
130	$30.00	6.19%
>130		6.19%

* Includes income taxes (i.e., results in revenue requirement without adding income taxes). The performance incentive awarded will be based on percentage of net benefits. The percentages are interpolated linearly between the performance levels. *Source:* Missouri Public Service Commission

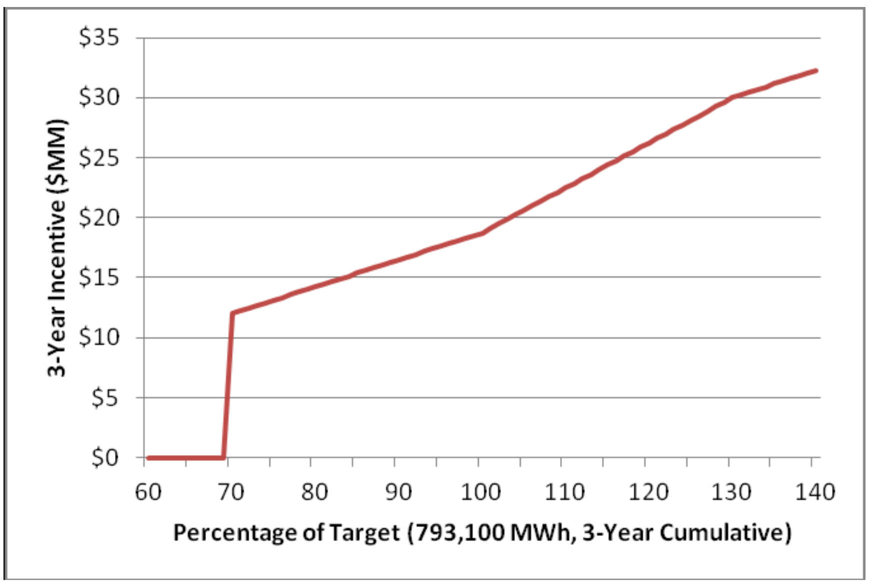

Figure A8. Ameren Missouri performance incentive schedule in dollars. *Source:* Missouri Public Service Commission.

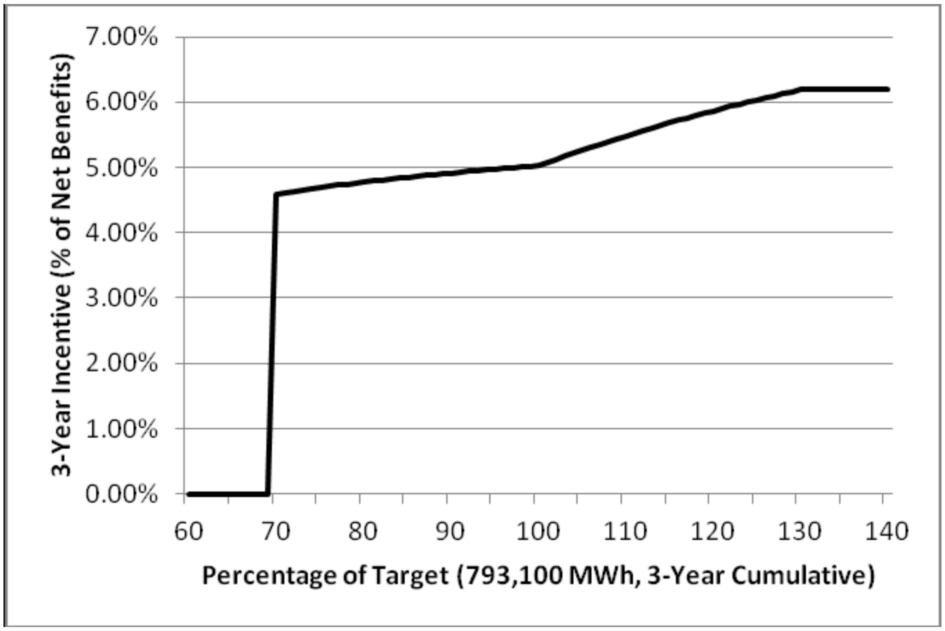

Figure A9. Ameren Missouri performance incentive schedule as percentage of net benefits. *Source:* Missouri Public Service Commission.

The agreement includes a provision for final recovery true up of any performance incentive award amount.

Outcomes

It may be too early in the initial program plan periods for the utilities with DSIMs in place to assess the full impacts and associated financial outcomes, particularly as they apply to the performance incentives, as these are not determined until full EM&V results are determined after the applicable full program plan periods (3 years for Ameren Missouri and GMO, 18 months for KCP&L's initial plan). Ameren Missouri is exceeding program savings targets and is on track to receive full incentive amounts.

Missouri's DSIMs (addressing both the throughput disincentive and shareholder performance incentive) are very new. Ameren Missouri's and GMO's mechanisms each have completed the first full program years (2013 data are complete; 2014 data are not yet final) associated with the mechanisms. KP&L's mechanism was enacted in July 2014.

While early in the process associated with determining and awarding these incentives, the impact of having these mechanisms in place is dramatic. It is clear from discussions with Missouri stakeholders that establishing these mechanisms has enabled affected utilities to initiate and fund large portfolios of customer energy efficiency programs.

Ameren Missouri's recent history with energy efficiency program funding well illustrates the dramatic impact that MEEIA and authorization of DSIMs have had. Prior to MEEIA's passage, Ameren Missouri had energy efficiency programs in place representing total utility investment of about $70 million for the three-year period of 2009–2011. During this time Ameren Missouri received only program cost recovery—no lost revenue recovery or shareholder incentive amounts. Ameren Missouri executives viewed this business model for energy efficiency as unsustainable. As a result Ameren Missouri "put on the brakes" to its programs and reduced its program funding from $30 million in 2011 to a bridge funding of $8 million in 2012. MEEIA had just passed in 2012, and Ameren Missouri sought to retain the basic foundations of its energy efficiency programs in place in anticipation of getting regulatory treatment of costs and incentives to allow it to return to a much higher level of investment. With the commission's approval of its DSIM, Ameren Missouri's planned investment did indeed jump—up to $35 million in 2013, $45 million in 2014, and as much as $65 million in 2015. As viewed by the director of Ameren Missouri's programs, accounting for all three legs of the financial stool "had a profound impact on Ameren Missouri's investments in energy efficiency." A clean energy advocate echoed this conclusion, commenting that such action "definitely changed Ameren Missouri's behavior" regarding its energy efficiency programs.

As noted earlier, MEEIA does not require utilities to fund and provide energy efficiency programs. They are voluntary. Consequently, there needed to be incentives for the utilities to engage fully and provide energy efficiency programs and services. To date, three out of four regulated electric utilities in Missouri have established energy efficiency programs in response to MEEIA. The remaining utility, Empire Electric, is developing proposals and initiated a MEEIA filing in late 2013.

Evaluation

MEEIA established guidelines and specific requirements for EM&V. Determination of the performance incentive is based on ex-post program evaluations. Consequently, annual impact evaluations are required to determine net energy and demand savings.

Process

The performance incentives are determined from the savings impacts as quantified from program evaluations completed by independent third-party contractors for the utilities. The Public Service Commission of Missouri contracts with an evaluation auditor to review the evaluations completed by the utilities' contractors in order to help ensure their accuracy. The parties filed a stipulation and agreement on February 11, 2015, to settle all issues related to final EM&V for 2013 and to put into place a process to address EM&V issues for 2014 and 2015.

Commission staff commented that the learning curve is very steep for utility energy efficiency programs; it is taking time for all parties involved to work through the processes and issues associated with the development, implementation, and evaluation of programs, including determination of utility incentives.

Looking Ahead

The rules established for MEEIA are undergoing a required review that began in 2015. Missouri's regulations requiring integrated resource planning remain in place; such proceedings occur separately from MEEIA program filings.

Ameren Missouri filed its next three-year MEEIA program plan in December 2014. The existing DSIM is part of this plan. The proposed level of investment in energy efficiency programs remains about the same as the existing three-year MEEIA program plan, but expected savings are about half.

Missouri's DSIMs in place are too new to be able to assess their full impact and effectiveness. It is clear that having these in place has been a catalyst for Missouri's electric utilities to move ahead with portfolios of customer energy efficiency programs representing significant utility investment.

While more time and analysis will be needed before a full assessment of the effectiveness of Missouri's DSIMs have been, it already is clear, in the words of one Missouri observer, that having mechanisms in place to address the utility business model "has been effective in moving the need in a positive direction in a state where there had been no incentives for utility energy efficiency."

OKLAHOMA

Background

Utility performance incentives for energy efficiency programs were first approved in Oklahoma for Public Service Company of Oklahoma (PSO) in 2008.[37] The incentive structure approved for PSO was a shared savings approach that allowed PSO to recover 25% of the net benefits for those programs that achieve measurable benefits. The total resource cost test was to be used in calculating the net benefits of the programs. The mechanism also allowed PSO to recover 15% of program costs as an incentive for programs in which savings cannot be determined. The projected savings benefit was then trued up to the actual savings benefit following completion of the program year.

Oklahoma Gas and Electric (OGE) was first approved to receive performance incentives in 2009.[38] OGE's approved performance incentive structure was similar to the PSO approved shared benefit structure. However the OGE performance incentive was limited to 15% of the net shared benefits for eligible programs with a TRC score higher than 1.0 and capped at $2.7 million in the first year. OGE's request to earn a performance incentive on education programs was denied by the Oklahoma Corporate Commission (OCC).[39] As part of the settlement agreement approved by the OCC, OGE was also allowed to earn an incentive of 15% of program costs on programs that scored less than 1.0 on the TRC test.

In 2012, the OCC approved a settlement agreement for PSO to continue offering demand response and energy efficiency programs for an additional three years. The settlement agreement contained a reduced performance incentive for PSO, allowing the company to recover 15% of shared benefits instead of the previously approved 25%. The settlement agreement also allowed PSO to recover an incentive of 15% of program costs on education programs.

[37] Cause No. 200700449. Order No. 555302 issued June 13, 2008.

[38] Cause No. 200900200. Order No. 573419 issued January 21, 2010.

[39] Education programs represented 7.5% of the total DSM program budgets and included home energy reports.

In 2012, OGE received approval from OCC to offer programs for 2013–2015.[40] As part of the approved settlement agreement, OGE is allowed to continue the approved performance incentive structure from Cause No. 200900200. For the new three-year program cycle, OGE added two programs focused on decreasing peak demand, the SmartHours program and integrated volt var control (IVVC). These two programs are not eligible for any performance incentives.

In 2010, Oklahoma Natural Gas and CenterPoint Energy Resources received authorization to offer efficiency programs.[41] As part of this authorization, both companies received approval to collect a performance incentive of 15% of the net benefits for programs passing the TRC. The mechanism was similar to electric program performance incentives at the time. An incentive of 15% of the net benefits was awarded for programs passing the TRC and 15% of program costs for programs not passing the TRC. Program budgets for both companies were fixed for proposed three-year cycles.

Other Relevant Regulatory Features

Oklahoma does not have an energy efficiency resource standard at this time. The OCC also has yet to approve decoupling for any electric utility in the state.

Policy Details

The details of the current performance incentives for OGE and PSO are detailed in table A12 below. Both current incentive structures were approved by the OCC in 2012. Both companies collect a projected shared savings incentive and then true up the results following the end of the program year. The shared savings mechanisms for PSO and OGE are similar but have significant differences. For example, while PSO and OGE both collect 15% of the net benefits of energy efficiency programs, the net benefits are calculated in different ways. OGE calculates the incentive as 15% of the net benefits of the total resource cost test for programs with a score over 1.0. PSO calculates net benefits using the Program Administrator Cost Test. This difference allows PSO to collect a higher level of incentives because the costs included in the total resource cost test are greater than the costs included in the Program Administrator Cost Test. Both companies collect 15% of program costs for programs failing to meet a 1.0 score on the PACT or TRC. PSO also collects an incentive on demand response programs while OGE does not. Finally, PSO collects an incentive of 15% of program costs for education programs while OGE does not.

Outcomes

Table A12 outlines recent performance for electric utilities in Oklahoma and the associated incentives.

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[40] Cause No. 201200134. Order No. 605737 issued December 20, 2012.

[41] Cause Nos. 201000143 and 201000148. Order Nos. 585366 issued May 12, 2010 and 583869 issued March 25, 2011.

Table A12. OGE and PSO recent performance

Year	Program cost	Annual savings (MWh)	Performance incentive	Percentage of total program costs
Oklahoma Gas and Electric				
2011	$18,200,806	64,743	$3,105,699	17%
2012	$14,662,068	34,406	$2,609,501	18%
Public Service Company of Oklahoma				
2012	$21,963,690	75,629	$5,526,804	25%
2013	$22,335,179	67,901	$4,691,690	21%

Source: Oklahoma Corporate Commission

The data show utilities have performed well in regard to offering cost-effective programs with sizable net benefits. However it should be noted the incentives are calculated differently for OGE and PSO, thereby making direct comparisons between the two companies difficult. It is also important to note that the true-up data for companies in Oklahoma is not filed publicly, making it difficult to determine how actual results and spending compare with projected results and spending.

Figure A10 illustrates the increase in Oklahoma electric energy efficiency program savings.

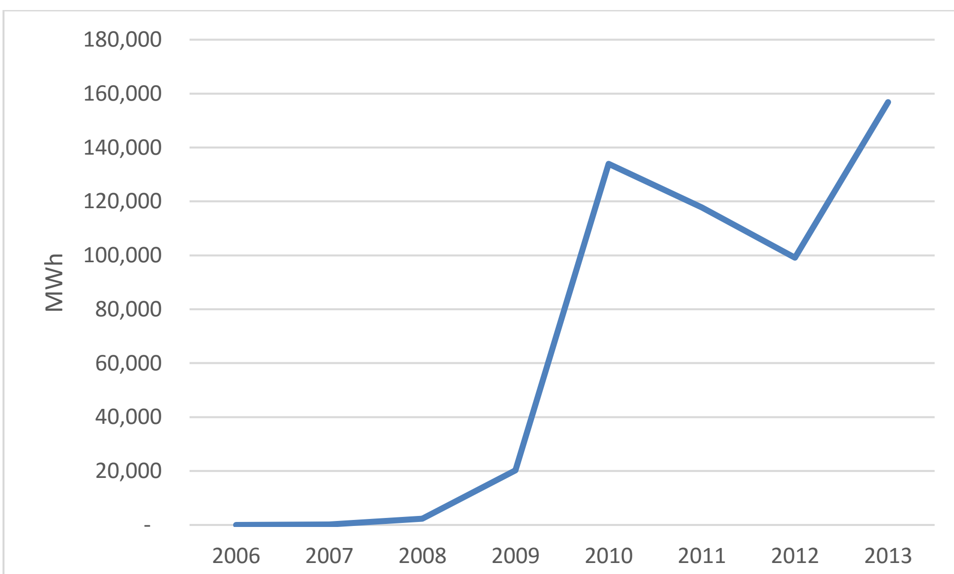

Figure A10. Oklahoma Energy Savings 2006–2013. *Source:* ACEEE 2014 *State Scorecard.*

Discussion

Oklahoma has a very favorable performance incentive policy in place for electric and gas utilities. The shared savings approach has allowed utilities in Oklahoma to earn as much as 25% of total program costs as an incentive since the inception of the policy. The general consensus of stakeholders interviewed by ACEEE is that the policy has been effective in encouraging utilities to achieve greater energy efficiency savings. Some stakeholders expressed happiness with the progress made in Oklahoma but stated that the utilities could be achieving much greater savings and would be doing so if the state had an energy efficiency resource standard. Other stakeholders expressed concern that without the incentive policy in place, it is unlikely the utilities would offer any programs at all.

Looking Forward

The performance incentive structure in Oklahoma will be modified following the current three-year program plans (2015). The changes are a result of a 2013 rulemaking proceeding to modify several aspects of gas and electric utility rules. Beginning in 2015, utilities will only be allowed to collect an incentive if the portfolio achieves 80% of the individual utility's goal and the portfolio has a TRC score higher than 1.0. Utilities will still be able to earn an incentive on programs with a TRC result of less than 1.0, but only if the portfolio as a whole passes the test. If savings beyond 100% of the utility savings goal are achieved, 15% of net benefits will be paid. The rule is not explicit in a maximum threshold for the total incentive, only the minimum. Finally, the new rule does not have explicit penalties but does have language giving the commission the ability to reduce the incentive if the utility exceeds spending targets. The new changes are expected to simplify the process and level the playing field as all utilities will have the opportunity to earn the same incentive.

RHODE ISLAND

Background

Rhode Island has had performance incentives in place for Narragansett Electric Company (National Grid) since 1990. The electric performance incentive has changed over time. Initially, the Rhode Island Public Utility Commission (RIPUC) allowed National Grid to earn a total 4.25% of the energy efficiency budget, excluding evaluation costs. The company was required to reach 45% of the targeted annual energy savings goal for a specific sector to begin earning a performance incentive. In 2004, the RIPUC approved changes to the mechanism to increase the allowed incentive from 4.25% to 4.4% of eligible program costs. [42] In addition to the energy savings goal, National Grid was also allowed to earn an incentive for achieving goals in five performance metric categories for specific programs. The threshold to earn the incentive for each sector was also increased from 45% to 60%.

In 2007, RIPUC also approved a performance incentive for National Grid's gas efficiency programs. The target incentive rate was 4.4% of eligible program costs, just as it was for electric programs. The threshold and maximum incentive structure were also the same as the electric model. The sector categories for incentives for natural gas energy efficiency performance were initially residential and commercial and industrial (C&I). The savings targets are measured in annual MMBtu.

In 2009, the sectors for which the incentive targets are measured for electric performance incentives were changed from residential, small C&I, and large C&I to low-income residential, non-low-income residential, and large C&I. The gas incentive sectors were also

[42] See Rhode Island Public Service Commission Order 18152.

changed by splitting the residential sector into low-income residential and non-low-income residential. Also in 2009, a provision was introduced to adjust the goals for efficiency in actual spending relative to budget in the achievement of savings goals. In 2010, the performance metric incentives for five separate categories related to specific programs were eliminated to simplify awarding the incentive. In 2012, the gas and electric performance incentive underwent significant changes as the savings target incentive rate was increased to 5% and the threshold to earn the incentive was increased from 60% to 75%. In the company's settlement agreement for 2015, additional changes were made, as described in the section on looking ahead.

Other Relevant Regulatory Features

The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 requires utilities to acquire all cost-effective energy efficiency.[43] The act also establishes requirements for strategic long-term planning and purchasing of least-cost supply and demand resources, and three-year energy saving targets. The energy savings targets are proposed by the Rhode Island Energy Efficiency and Resources Management Council. High-level strategies and illustrative budgets to reach those targets are developed in three-year plans filed by National Grid. Within the three-year plan time frame, National Grid then files annual plans containing detailed goals, budgets, and program plans for PUC approval. Revenue decoupling is also fully implemented by National Grid electric and gas in Rhode Island.

Policy Details

As of 2014, the company may earn a target-based incentive rate equal to 5% of the eligible spending budget in a program year for achieving electric and gas energy savings goals. The incentive mechanism establishes an incentive of 1.25% of the annual budget for achieving 75% of the savings goals in a sector. This increases linearly to 5% of the annual budget for achievement of 100%, and increase linearly from that point to 6.25% of the annual budget for achieving 125% of the savings goals. The company must achieve at least 75% of the targeted performance to begin earning any incentive. Figure A11 illustrates the current incentive mechanism and how it differs from the 2012 mechanism.

[43] http://www.ripuc.org/eventsactions/docket/3759-RIAct.pdf

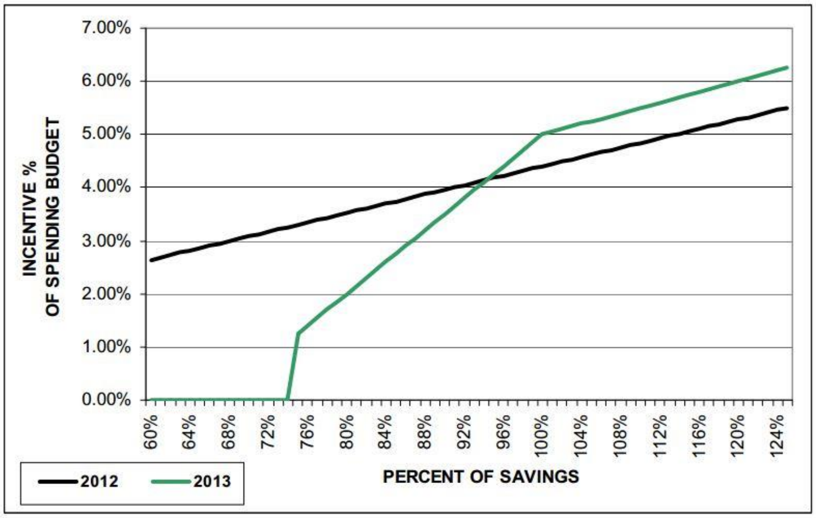

Figure A11. Shareholder incentive mechanism, 2012 and 2013. *Source:* National Grid 2013 EE Plan Docket No. 4366, page 24.

Outcomes

Table A13 details program spending, savings, and performance incentives earned since 2010 for electric and gas programs.

Table A13. Rhode Island performance incentives, 2010–2013

Year	Program cost	Annual savings	Incentive amounts	Percentage of incentive target*
		Electric (MWh)		
2010	$23,747,710	81,275	$1,333,996	107.1%
2011	$32,972,679	96,009	$1,929,273	93.5%
2012	$45,768,146	119,666	$2,469,411	93.%
2013	$62,372,290	157,121	$2,997,681	98.9%
		Gas (MMBtu)		
2010	$5,197,448	140,097	$231,310	126.8%
2011	$4,518,069	119,613	$239,863	117%
2012	$12,554,591	229,811	$586,036	99.2%
2013	$17,925,668	312,433	$968,229	108.6%

* The value in this column represents the total percentage of incentive target met. However the incentive is actually calculated at the sector level, and the company must meet sector-level thresholds to earn the incentive for each sector. *Source:* Rhode Island Public Service Commission.

The data show that the electric and gas programs have routinely performed within the bounds of 90% to 125% of the savings targets. It is also worth noting that the 2013 electric program performance increased following an increase in the target incentive rate following two years of declining performance.

Figure A12 illustrates the increase in Rhode Island electric energy efficiency program savings.

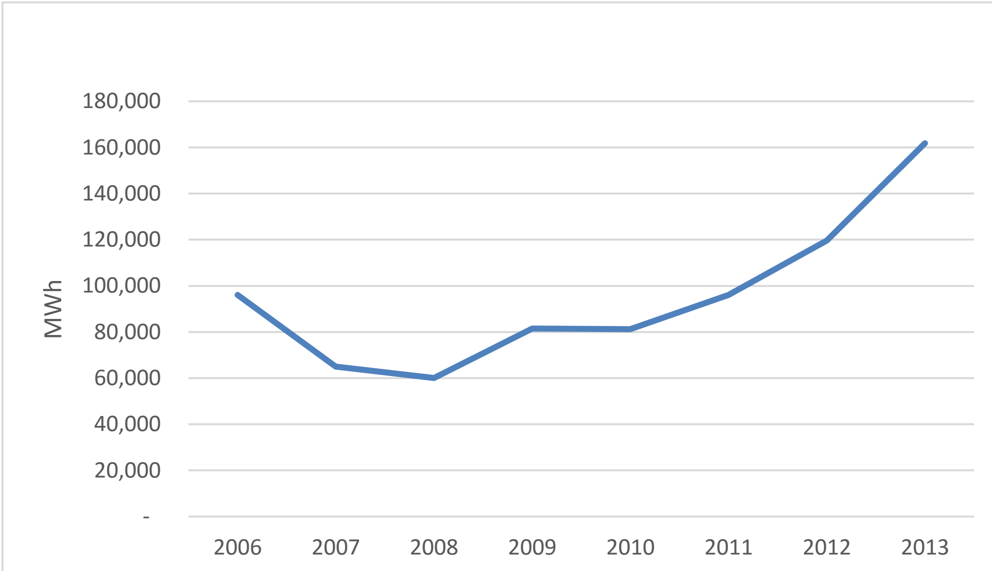

Figure A12. Rhode Island energy savings, 2006–2013. *Source:* 2014 *State Scorecard.*

Discussion

The unanimous response from the interviews conducted by ACEEE staff was that incentives have been effective in encouraging National Grid to achieve greater results with its energy efficiency programs. One of the strengths of the Rhode Island performance incentive mechanism is that the stakeholders have the opportunity to propose modifications to the incentive structure annually.[44] This allows for a nimble incentive that can change as circumstances change. For example, program performance declined in 2011 and 2012 as National Grid struggled to spend approved budgets and meet savings goals during a period of aggressive program ramping up and corporate restructuring. After the second straight year of performance below goals, the stakeholder group and National Grid agreed to increase the 4.4% award to 5% of the eligible program costs for achievement of 100% of the energy savings goals (with a maximum threshold of 125% for a 6.25% incentive). Since the change in incentive level, however, National Grid has stabilized its energy efficiency delivery efforts. At the same time, the minimum threshold was increased from 60% to 75% of performance targets to begin earning an incentive. This change has seemed to achieve the desired effect as program spending and performance increased to pre-2011 levels in 2013. The mechanism has served to focus utility attention on achieving their goals.

Looking Forward

The 2013–2014 winter was colder than average, and high natural gas demand caused significantly higher spot market prices. The result of these conditions is very high peak energy prices. To reduce peak demand and thus avoid higher prices, the stakeholder group

[44] While the stakeholder process can propose changes to the incentive mechanism and other aspects of National Grid's program plan, ultimately any modifications must be approved by the RIPUC.

and National Grid agreed upon a demand-reduction incentive. This incentive was designed and agreed upon to increase demand reduction in the summer and provide an increased focus on demand reduction throughout the year. This proposal, introduced as part of the 2015 Energy Efficiency Program Plan, was approved by the RIPUC.

The newly designed performance incentive only applies to electric program budgets. In order to promote the achievement of demand savings goals, the company proposes to set aside 30% of the current incentive to be available for the achievement of summer annual MW savings goals. This would allow the company to earn a target-based incentive rate equal to 3.5% of the eligible annual budget for achieving MWh savings goals and 1.5% of the annual spending budget for achieving MW savings goals.

TEXAS

Background

Texas first established a performance incentive mechanism for electric utilities in 2008. The performance incentive, or bonus as it is referred to in Texas, allowed electric utilities to earn 1% of net benefits for every 2% of a company's goal that it exceeded. In an effort to limit disproportionately high bonuses, the Public Utility Commission of Texas (PUCT) capped the bonus not to exceed 20% of total program costs for each utility. The established threshold for a utility to earn a bonus was 100% of the demand and energy goals as defined in Texas law. Net benefits were calculated by subtracting the net present value of the avoided cost of energy and capacity from the program costs. Program costs included all incentives and administrative and program evaluation costs. Demand and energy savings were gross values; that is, they are not adjusted for naturally occurring savings or free riders.[45] The rule also allowed utilities to earn an additional bonus for achieving at least 120% of its demand reduction goal with at least 10% of its savings met through hard-to-reach programs. This additional bonus was equal to 10% of the first bonus. Hard-to-reach programs were designed to target residential customers with an annual household income at or below 200% of the federal poverty guidelines.

The performance bonus was modified in 2011. Previously, a utility was awarded a bonus of 1% of net benefits for every 2% a company exceeded its goals, up to 20% of total program costs. This was modified to limit the bonus to 10% of net benefits instead of 20% of total program costs. This change has created the possibility for utilities to earn much more than 20% of program cost as a performance incentive. Companies in 2012 earned between 10% and 31% of total program costs as a performance incentive. In 2013, companies were earning between 31% and 46% of program costs as a performance incentive. The change was instituted to encourage utilities to achieve savings with greater net benefits.[46] The 2011 changes eliminated the additional bonus incentive previously awarded to utilities achieving

[45] Performance incentives first established in Order Adopting the Repeal of §25.181 and §25.184 and of new §25.181 as Approved at the March 26, 2008 Open Meeting. Project No. 33487.

[46] Modifications approved in Order Adopting Amendments to §25.181 as Approved at the September 28, 2012 Open Meeting.

120% of its demand reduction goal with at least 10% of its savings met through hard-to-reach programs.

Other Relevant Regulatory Features

Texas was the first state to adopt an Energy Efficiency Resource Standard in 1999. Currently, the annual goals mandate a 30% reduction of annual growth in demand for residential and commercial customers. However the structure of the goal allows a utility to meet the goals by reducing demand by 0.4% of its summer-weather-adjusted peak demand for the previous year. Texas does not currently allow electric utilities full decoupling or lost revenue recovery for offering energy efficiency programs.

Policy Details

Electric utilities may earn performance bonuses for achieving 100% of demand and energy savings targets prescribed in Texas law. The demand and energy goals require utilities to reduce annual growth in demand for residential and commercial customers by 30% for the previous year. If a 30% reduction is equivalent to at least 0.4% of summer-weather-adjusted peak demand for the combined residential and commercial customers for the previous year, 0.4% becomes the new goal.[47] Once a utility exceeds 100% of the approved goal and does not exceed spending limits, the utility will earn 1% of the net benefits for every 2% the goal is exceeded, with a maximum of 10% of the utility's total net benefits. Utilities must also spend at least 5% of the program budget on hard-to-reach savings to be eligible for a bonus.

Outcomes

Table A14 contains the aggregate results for energy efficiency programs and performance bonuses since 2008. Data were collected for all 10 electric utilities operating programs and receiving performance bonuses.

Table A14. Texas energy efficiency results and performance bonus, 2008–2013

Year	Total energy efficiency expenditures	Demand savings (MW)	Energy savings (GWh)	Performance bonus	Bonus as percentage of total expenditures
2008	$96,127,475	202	580	$19,238,502	20.01%
2009	$105,809,802	240	560	$21,148,220	19.99%
2010	$105,290,918	301	533	$20,432,317	19.41%
2011	$113,911,740	270	529	$21,487,140	18.86%
2012	$119,834,458	402	288	$28,736,107	23.98%
2013	$138,715,805	415	548	$53,678,151	38.70%

Source: Utility annual energy efficiency reports filed in Project Nos. 42264, 41196, 40194, 39105, and 37982

[47] §25.181—15. The establishment of demand and energy goals is far more complicated than described in this case study. For the purpose of brevity and focus on performance incentives, a detailed discussion of energy and demand goal setting has been withheld.

Utilities in Texas have rarely failed to earn an annual performance bonus since the policy began in 2008. Demand savings have increased annually, with the only exception being a slight drop in 2011. Following the modest decline in 2011, demand savings have increased to over 415 MW in 2013, almost as big as a typical power plant. Energy savings have experienced a decline since the 2008, with a notable drop in 2012. With modest goals, however, most utilities exceed annual energy savings goals necessary to earn performance bonuses.

Figure A13 depicts the results.

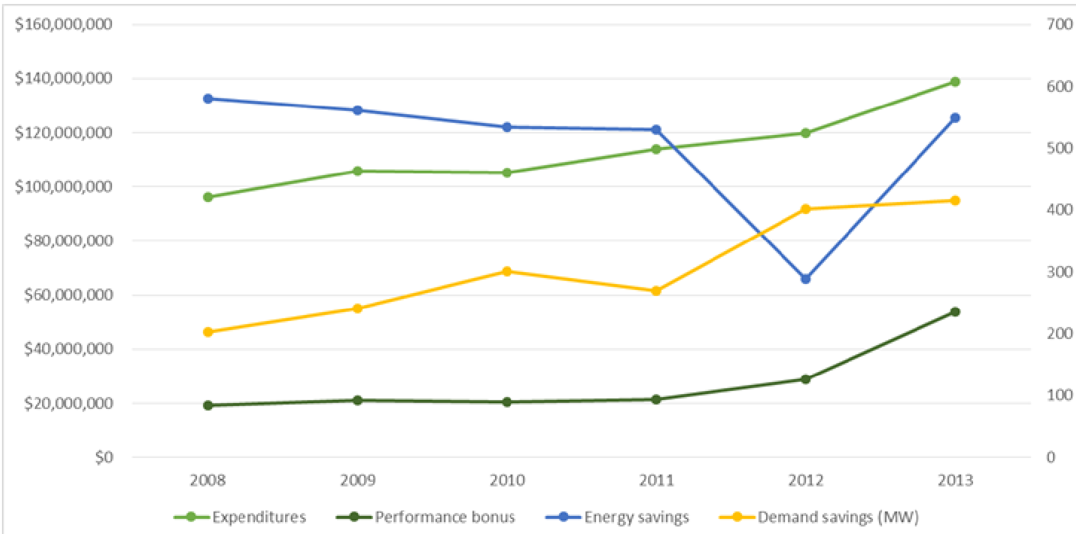

Figure A13. Texas energy efficiency results and performance bonus, 2008–2013. *Source:* Utility annual energy efficiency reports filed in Project Nos. 42264, 41196, 40194, 39105, and 37982.

Discussion

The performance bonus mechanism has been partially influential in increasing demand savings but has had a questionable effect on energy savings. Energy savings have declined since 2008, the year the performance bonus was first authorized. Demand savings have more than doubled during this same time and have increased markedly since 2011. While there were changes to the performance incentives structure at this time, the increase in demand savings can be attributed to the PUCT request to increase demand reductions from load management programs. However most utilities have exceeded energy savings targets since 2008. The spike in demand reduction performance coincided with the change in the performance incentive structure in 2011. Also in 2011, the Texas legislature adopted Senate Bill 1125 that modified the energy efficiency goal structure to include a peak demand component.

Many companies performed at levels significantly beyond goals and the maximum incentive level. As an example, Southwestern Electric Power Company met 194% of its energy goal and 238% of its demand goal in 2012. The calculated performance incentive for this level of achievement was $8,060,397. However SWEPCo only earned the maximum bonus based on 10% of net benefits, or $1,168,476. Many Texas utilities in 2012 and 2013 filed similar bonus calculations collecting a much lower bonus due to limits than what would have been potentially available. In 2013, AEP Texas Central Company calculated a performance bonus of $38,212,549 but only collected $4,459,958, the maximum allowed as 10% of net benefits.

As the data above show, the performance incentives in Texas are substantial, exceeding 38% of program cost in 2013 in aggregate. The performance incentives in Texas are based on a net benefits approach. Net benefits are results of calculations based on the avoided cost of energy. The avoided cost of energy in Texas is updated annually. The frequent updates can have significant impacts on the calculation of net benefits and the performance incentive. In 2012, the avoided cost of energy was 6.4 cents per kWh. In 2013, the value increased to 10.4 cents per kWh but then declined to 4.6 cents per kWh in 2014. Large changes in avoided cost in Texas explain part of the increase in performance incentives awarded in 2013 from 2012.

In comments filed in both Project No. 33487, the establishment of the performance bonus, and in Project No. 39674, the modifications to the limits of the performance bonus, commenters expressed concern with the level of incentives allowed. However Texas does not allow lost revenue recovery or have a decoupled rate structure. Many utilities view the incentive structure as a way to allow a company to earn part of the lost revenues associated with energy efficiency.

During PUCT rule-making proceedings to modify the performance incentives and energy efficiency goals, commenters have objected to the use of gross savings for goal attainment and performance bonus calculation.[48] The PUCT specifically requires the performance bonus to be calculated using demand or energy savings from programs implemented to obtain goals.[49] By definition, this would only include net savings, but utility filing projections and results are in gross savings terms. Evaluations in Texas do not include net-to-gross analysis, making it difficult to determine if utilities are earning incentives on savings not attributable to specific programs.

Looking Forward

Currently, there are no changes expected to the performance bonus mechanism in the near future. Changes to the mechanism have historically been initiated in the Texas legislature and worked through the PUCT rule-making process. In both of the major rule makings associated with the performance bonus, parties have actively participated in shaping the final rules. However, without legislative action, it is unlikely any changes will happen soon.

Table A15 shows energy demand goals and performance.

[48] See comments of Cities in Project No. 39674.

[49] §25.181(h): Energy Efficiency Performance Bonus.

Table A15. Texas energy and demand goals and performance, 2008–2013

Year	Demand goal (MW)	Demand savings (MW)	Percent age of goal met	Energy savings goal (GWh)	Energy savings (GWh)	Percentag e of goal met
2008	117	202	172%	375	580	155%
2009	134	240	179%	403	560	139%
2010	142	301	212%	391	533	137%
2011	147	270	183%	400	529	132%
2012	152	402	265%	366	288	79%
2013	175	415	237%	442	548	124%

Source: Utility annual energy efficiency reports filed in Project Nos. 42264, 41196, 40194, 39105, and 37982

VERMONT

Background

Performance incentives have existed in Vermont since the inception of Efficiency Vermont in 1999. Efficiency Vermont is the statewide energy efficiency program operated by Vermont Energy Investment Corporation (VEIC). VEIC was initially contracted through the Vermont Public Service Board (VPSB) to serve as the energy efficiency service provider under a contract agreement but has operated as a jurisdictional regulated utility under a long-term 12-year Order of Appointment since 2010. When VEIC first contracted with the VPSB in 1999, the contract allowed VEIC to earn a percentage of program cost for meeting performance targets in specific areas over the course of a three-year program plan. The performance targets are known as quantifiable performance indicators (QPIs). The initial contract and agreements for subsequent three-year performance periods have allowed VEIC to earn between 3.4% and 4.3% of program costs as compensation (guaranteed return and a performance incentive). Since 1999 a percentage of this compensation was guaranteed and is known as an operations fee.

The remaining compensation is the performance incentive and is at risk. The performance incentive-based compensation can only be earned if VEIC meets the QPIs. The percentage of compensation allocated to the operation fee and performance incentive has fluctuated some between three-year performance periods. In the most recent performance period, 2015–2017, the operations fee is 40% and the performance incentive is 60% of total compensation. VEIC's QPIs and compensation structure are revisited and modified prior to every three-year cycle through the Demand Resource Plan (DRP) proceeding before the VPSB, with the most recent QPIs established for the 2015–2017 performance period in 2014.

For the 2015–2017 performance period, VEIC proposed an increase in the compensation rate from 4.1% to 6% (margin rate), and to equally distribute compensation on a 50–50 basis between the operations fee and performance incentive, as opposed to the current 40–60 split as recommended by the Public Service Department (PSD). VEIC had first recommended an increase from 4.1% to 6%.[50] In addition, VEIC recommended the calculation method for the compensation rate continue to be based on a margin approach (used to set the compensation rate for the 2012–2014 performance period). The margin approach is based on the total percentage of compensation above cost, as opposed to a markup rate as a percentage of the total program cost as recommended by the PSD. The VPSB approved an increase to 4.5% on a markup basis (equating to a 4.3% margin rate) while maintaining a 40–60 split between guaranteed compensation and at-risk performance incentives.[51]

The City of Burlington Electric Department (BED) operates electric energy efficiency programs with established performance targets. BED's energy efficiency costs are recovered dollar for dollar at no additional cost to ratepayers (no operations fee or performance incentive). Vermont Gas Systems (VGS) also operates gas efficiency programs. As an incentive to operate programs, VGS is allowed to earn a rate of return on efficiency investments. The rate of return VGS earns on efficiency investments is the same rate of return approved in the company's last rate case.

Other Relevant Regulatory Features

Vermont has a nontraditional energy efficiency resource standard. Vermont law requires energy efficiency budgets to be set at a level that would realize "all reasonably available, cost-effective energy efficiency." Every 3 years the DRP produces an annual electric budget and savings 20-year forecast. Vermont law required utilities in the state to perform least-cost integrated resource planning "to identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning, including efficiency, conservation and load management alternatives, wise use of renewable resources, and environmentally sound energy supply."[52] Resource planning requires comprehensive energy efficiency programs designed to acquire the full amount of cost-effective savings.[53] Vermont also encourages energy efficiency through innovative rate making including inclining block rates and decoupling approved for Green Mountain Power and Vermont Gas.

Policy Details

The current electric performance incentive allows VEIC to earn a percentage of total program costs as an incentive. The incentive amount earned is determined by VEIC's ability to meet specific targets and minimum requirements for 15 electric-efficiency and 4 thermal-energy-and-process-fuels (TEPF) QPIs. Each QPI focuses on different policy objectives of the statewide efficiency program.

Electric-efficiency QPIs 1-7 are positive incentives awarded to VEIC for meeting a target for specific tasks. For example, QPI 1 targets energy savings. VEIC can begin earning an

[50] VEIC April 6, 2014, compensation recommendation: http://psb.vermont.gov/docketsandprojects/eeu/drp2013.

[51] EEU-2013-01, Order Regarding Energy Efficiency Utility Budgets for Demand Resources Plan. Page 60. July 9, 2014.

[52] 30 VSA §202a(2).

[53] 30 VSA §218c(a)(2).

incentive when 90% of the target is reached. Reaching 100% of the target is known as a stretch goal because the targets for QPIs 1–4 are 20% higher than the expected results in these categories. VEIC is also able to earn an incentive for exceeding the target goal. For QPIs 1–4, there is no upper limit to this incentive, but it is capped at total incentive available ($4,442,682) for the three-year period.

Table A16 shows QPIs 1–7.

Table A16. Efficiency Vermont quantifiable performance indicator targets 1–7 for 2015–2017 program cycle

No.	QPI	Target	Cap	Threshold
1	Annual incremental savings	321,800 MWh	none	90%
2	Total resource benefits	$336,300,000	none	90%
3	Summer peak demand savings	41.3 MW	none	90%
4	Winter peak demand savings	53.7 MW	none	90%
5	Business comprehensiveness	11% increase in depth of savings	$196,000 or 5%	80%
6	Residential market transformation	42% of new homes above code	$117,000 or 3%	85%
7	Business market transformation	500 partners	$117,000 or 3%	80%

Source: Order in Case No. EEU-2013-01

QPIs 8-15 (table A17) set minimum performance levels for specific public policy objectives. If VEIC does not meet the minimum performance level, it can lose the opportunity to earn performance incentives earned in QPIs 1-7.

Table A17. Efficiency Vermont quantifiable performance indicator targets 8–15 for 2015–2017 program cycle

No.	QPI	Minimum requirement	Possible financial impact
8	Electric ratepayer equity	Benefit cost ratio greater than 1.2	$3,915,693
9	Residential ratepayer equity	Sector spending greater than $32,500,000	$614,825
10	Low-income ratepayer equity	Sector spending greater than $10,500,000	$614,825
11	Small business customer equity	2000 small business customers	$614,825
12	Geographic equity	Benefits goals for each geographic area	$204,942
13	Program implementation efficiency	Meet all schedule milestones	$68,314
14	Service quality	Achieve 92 or more metric points in the Service Quality and Reliability Plan	$150,000
15	Spending	103% of budgeted spending level	No limit

Source: Order in Case No. EEU-2013-01

VEIC has a total possible electric compensation of $6,526,155 for the 2015–2017 performance period. This figure includes $2,610,462 in guaranteed compensation (operations fee) and $3,915,693 at-risk. While VEIC is allowed a higher earning potential for some QPIs known as super stretch targets, the organization is not allowed to earn more than the total performance award incentive set aside.

Of the four TEPF QPIs, the first two have a positive performance award associated with target levels. The second two are minimum performance requirements, meaning if the requirements are not met, VEIC will lose the ability to lose all of the performance award associated with TEPF. VEIC has a total possible thermal compensation of $878,315 for the 2015–2017 performance period. This figure includes $351,326 in guaranteed compensation (operations fee) and $526,989 at risk.

Table A18 shows thermal efficiency initiatives.

Table A18. Vermont thermal efficiency incentives

No.	QPI	Goal	Possible award
1	Annual incremental MMBTu savings	100% = 246,000 MMBtu	$342,742
2	Residential single family comprehensiveness	Multi-component retrofit goal	$114,247
3	Residential sector spending	Greater than 62.5% of the total TEPF expenditures	If not met, opportunity to earn 10% of the 100% target level performance award is forfeited.
4	Low-income spending	Greater than 17% of the total TEPF expenditures	If not met, opportunity to earn 10% of the 100% target level performance award is forfeited.

Source: Order in Case No. EEU-2013-01

Outcomes

VEIC has been successful in earning a performance fee consistently throughout its tenure as the statewide program administrator. Table A19 shows VEIC performance for the two previous program cycles.

Table A19. VEIC performance 2006-2011

Period	Three-year budget	Three-year annual incremental net savings (MWh)	Operations fee	Performance fee	Total performance incentive
2009–2011	$95,274,004	292,406	$559,119	$2,693,748	$3,252,867
2006–2008	$66,179,500	287,442	$473,510	$2,347,510	$2,820,510

Source: End-of-cycle budget reports

In 2009–2011, VEIC outperformed expectations for some QPIs and earned a higher performance fee for these QPIs than what was originally expected. VEIC is also expected to meet targets in all QPIs for the 2012–2014 time period to earn the full performance fee allowed.

Figure A14 illustrates Vermont annual electric energy efficiency program savings.

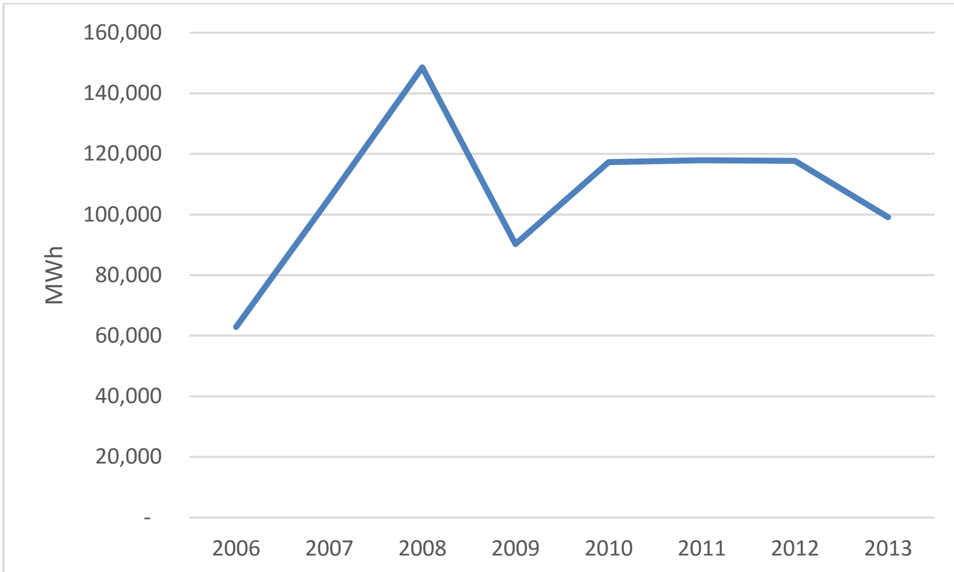

Figure A14. Vermont energy savings 2006–2013. *Source:* 2014 *State Scorecard*.

Discussion

The consensus among stakeholders interviewed in Vermont was that VEIC has done very well at balancing the goals contained in the QPI goal structure. VEIC's performance was recognized when it petitioned the VPSB to be the long-term statewide program administrator in Vermont. Subsequently, through a VPSB process, the company was awarded an 11-year order of appointment to continue working as the statewide administrator. Stakeholders also agreed the QPI structure provided a valuable mechanism to award VEIC for meeting specific policy objectives within the state. Instead of a traditional performance incentive awarding a company for meeting an energy or demand savings target, the QPI structure balances a suite of objectives and awards VEIC financially to ensure rate payer equity, spur market transformation, and achieve other state policy goals. In short, the structure is perceived as an effective mechanism for motivating performance Vermont.

Looking Forward

Under its order of appointment structure, VEIC will continue as the statewide program administrator in Vermont through 2021. Although small changes to the specific QPI and updates to the three-year performance period targets are expected, significant changes to the energy efficiency implementation structure are not expected in Vermont.

Appendix B. Questionnaire

Research Questionnaire: Financial Incentive Mechanism for Electric and Gas Utilities

The American Council for an Energy-Efficient Economy (ACEEE) is currently conducting national research on financial incentive mechanisms encouraging efficiency programs by utilities. We would greatly appreciate it if you would answer the following questions about the use of the utility-level shareholder incentive mechanism in your state. *Please note that ACEEE will report the information we gather as a general overall summary. We will not attribute specific answers or comments to specific individuals.* ACEEE will be happy to share the results of this research with the respondents to this survey.

Questions

Please answer the following questions about the financial incentive mechanism(s) in your state. Note that we leave space to answer the set of questions for up to two different incentive mechanisms. If different utilities have different types of incentive mechanisms, please answer the following items for each of two different utilities, beginning with the largest utility. If only one mechanism is used within the state, fill in all information under Mechanism One.

Mechanism One (e.g. for largest utility):

Applicable Utility(ies):

Indicate Mechanism Type (e.g. fixed incentive award, share of net benefits, performance-based incentive, increased rate of return, etc.):

1. When was it first authorized? When was the most recent version established?

2. Are there any threshold requirements that must be met to qualify for an incentive? If yes, what?

3. What is the overall incentive structure?

4. Is there a cap or ceiling on how much incentive can be earned? If yes, what?

5. Is the incentive payment based on net or gross savings?

6. Are there any related penalties? If yes, describe.

Please provide the following information for up to 2 utilities covered by Mechanism One (as described above) in your state. Please reference each of the two most recent program years for which data is available. Indicate program years and fill in information for each year in the table below.

	Utility 1: ____________	Utility 2: ____________
Program Year ______		
Actual earnings/award ($)		
Cost of energy efficiency programs to which incentive was applied ($)		
Total (1-year annual) energy savings achieved by the programs under the incentive mechanism (Please indicate kWh or therms)		
Program Year ______		
Actual earnings/award ($)		
Cost of energy efficiency programs to which incentive was applied ($)		
Total (1-year annual) energy savings achieved by the programs under the incentive mechanism (Please indicate kWh or therms)		

1. Please provide a citation or reference to the official documentation (e.g., statute, regulatory order, etc.) where this mechanism is established or described.

2. Is there a report, regulatory review, or other document that describes the mechanism and how it has worked in practice, and/or provides data on the actual award for the last two program years? If so, please provide link, contact person or reference where we may obtain a copy.

3. How are efficiency savings achieved under the incentive mechanism measured and verified?

4. Are there any significant differences between the incentive mechanisms as applied to electric versus gas utilities?

Mechanism Two:

Applicable Utility(ies):

Indicate Mechanism Type (e.g. fixed incentive award, share of net benefits, performance-based incentive, increased rate of return, etc.):

1. When was it first authorized? When was the most recent version established?

2. Are there any threshold requirements that must be met to qualify for an incentive? If yes, what?

3. What is the overall incentive structure?

4. Is there a cap or ceiling on how much incentive can be earned? If yes, what?

5. Is the incentive payment based on net or gross savings?

6. Are there any related penalties? If yes, describe.

Please provide the following information for up to 2 utilities covered by Mechanism Two (as described above) in your state. Please reference each of the two most recent program years for which data is available. Indicate program years and fill in information for each year in the table below.

	Utility 1: ____________	Utility 2: ____________
Program Year ______		
Actual earnings/award ($)		
Cost of energy efficiency programs to which incentive was applied ($)		

Total (1-year annual) energy savings achieved by the programs under the incentive mechanism (Please indicate kWh or therms)		
Program Year ______		
Actual earnings/award ($)		
Cost of energy efficiency programs to which incentive was applied ($)		
Total (1-year annual) energy savings achieved by the programs under the incentive mechanism (Please indicate kWh or therms)		

1. Please provide a citation or reference to the official documentation (e.g., statute, regulatory order, etc.) where this mechanism is established or described.

2. Is there a report, regulatory review, or other document that describes the mechanism and how it has worked in practice, and/or provides data on the actual award for the last two program years? If so, please provide link, contact person or reference where we may obtain a copy.

3. How are efficiency savings achieved under the mechanism measured and verified?

4. Are there any significant differences between the mechanisms as applied to electric versus gas utilities?

Overall Questions

We'd be interested in any thoughts you have on these last two questions. Again, we will NOT be quoting anyone by name.

1. Are there any suggestions you would make to another state who was thinking of adopting a utility energy efficiency performance incentive such as the mechanism(s) used in your state?

2. Please provide any additional insights or important information about efficiency incentives for utilities in your state that we have not covered above.

If you have any questions or comments about this survey, please contact Seth Nowak at the American Council for an Energy-Efficient Economy at (608)256-9155 or snowak@aceee.org

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Please provide your preferred contact information:

Name ________________________________

State________________________________

Phone________________________________

Email________________________________

THANK YOU VERY MUCH FOR YOUR ASSISTANCE!

Appendix C. Incentive Amounts as Percentage of Energy Efficiency Costs

Table C1. Incentive amounts relative to total costs by mechanism type by utility/administrator, state, and year

Net benefits		Multifactor		Savings-based	
Xcel electric (MN) 2011	68%	NSTAR (MA) 2013	6%	Consumers 2012 (MI)	15%
Xcel electric (MN) 2012	62%	NGRID (MA) 2013	6%	Consumers 2013 (MI)	15%
Otter Tail Power (MN) 2011	60%	NGRID (MA) 2012	6%	DTE Energy 2012 (MI)	15%
Georgia Power 2013	58%	Efficiency VT 2008	4%	DTE Energy 2013 (MI)	15%
Otter Tail Power (MN) 2012	56%	Efficiency VT 2011	3%	IPL (IN) 2013	8%
Georgia Power 2012	42%	PBFA (HI) 2014	2%	PSNH 2013	8%
AEP Texas Central 2013	36%	PBFA (HI) 2013	2%	PSNH 2012	9%
Xcel Energy (CO) 2012	29%	DC SEU 2012	1%	CT UI 2013	6%
SWEPCO (TX) 2012	26%	DC SEU 2013	1%	CT CL&P 2013	7%
PSO (OK) 2012	25%	WI FOE 2010-14	0.2%	CT UI 2012	6%
Xcel Energy (CO) 2013	22%			CT CL&P 2012	7%
PSO (OK) 2013	21%			RI NGRID 2013	5%
DEC (SC) 2014	18%			RI NGRID 2012	5%
OGE (OK) 2012	18%			NY all IOUs	4%
DEC (SC) 2013	18%				
OGE (OK) 2011	17%				
APS (AZ) 2012	14%				
SCE&G 2013	14%				
APS (AZ) 2013	9%				
SWEPCO AR	8%				
SWEPCO AR	8%				
Entergy Arkansas 2013	7%				
Entergy Arkansas 2012	6%				
SCE&G 2014	6%				

Source: Questionnaires completed by state commission staff