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Witness:	Stephen M. Kidwell
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-0036

REBUTTAL TESTIMONY

OF

STEPHEN M. KIDWELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
February 11, 2010

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DIRECT TESTIMONY

OF

STEPHEN M. KIDWELL

CASE NO. ER-2010-0036

I. INTRODUCTION

Q. Please state your name and business address.

A My name is Stephen M. Kidwell. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

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

A. I am the Vice President of Regulatory & Legislative Affairs for Union Electric Company d/b/a AmerenUE (AmerenUE or Company).

Q. Are you the same Stephen M. Kidwell who filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My purpose is to rebut the Staff of the Missouri Public Service Commission's (Staff) Revenue Requirement Cost of Service Report (Staff Report), and testimony of the Missouri Industrial Energy Consumers (MIEC) and the Missouri Energy Group (MEG) on the issue of cost recovery for Energy Efficiency measures. I will also address the testimony of the Office of Public Counsel (OPC) witness Russell W. Trippensee and the Staff recommendation on rate case expense, as well as the Staff's recommendation to disallow a portion of Edison Electric Institute (EEI) dues.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony discusses AmerenUE's incentives and disincentives for designing and implementing energy efficiency programs for its customers, apart from any state or federal mandates. I then discuss key insights from AmerenUE's new study of energy efficiency and demand response potential, which has recently been completed and contains information and recommendations that are specific to AmerenUE's customers and service area. The report describes in detail both the great potential and the great challenges inherent in attempting to convince customers to adopt more energy efficient lifestyles.

My testimony then turns to Senate Bill 376, or the Missouri Energy Efficiency Investment Act (MEEIA), which was enacted last year to address the disincentives which may inhibit utility investment in energy efficiency. I discuss the clear intent of the bill, as captured in press releases and other public statements at the time. I discuss Staff's legal opinion of MEEIA and show how this position contradicts the clear intent of the Legislature and Governor in enacting MEEIA. Unfortunately Staff's position adds greatly to the disincentives to energy efficiency investment faced by Missouri utilities and puts funding for current and future AmerenUE programs in serious jeopardy.

My testimony then turns to more detailed rebuttal of other witnesses. First, I address the concerns expressed by Staff witness John Rogers about AmerenUE's Lighting and Appliance Program. My testimony establishes the continuing value of residential lighting programs based on both national studies and data from our own service area. My testimony also demonstrates that AmerenUE's "market transformation" approach is well accepted across the country and that our evaluation protocol for the program is at the leading edge of current practice. Finally, I refute Mr. Rogers' claim that the program is somehow especially risky since it is being implemented in an area that is less than an entire state.

I also take up Staff witness Adam McKinnie's implication that AmerenUE is somehow deficient in its progress in rolling out energy efficiency programs. In fact, delays stem primarily from efforts to negotiate strong contracts and roll out high quality programs.

My testimony then turns to energy efficiency cost recovery. I describe how AmerenUE interprets the policy objectives and specific language of MEEIA and the model we have developed to support our policy analysis. This model and its results are discussed in more detail in the rebuttal testimony of AmerenUE witness Matt Michels. I use results from this model to expand and add additional detail to the proposal contained in my direct testimony and to evaluate both Staff's and MIEC's proposals. Staff's proposal, which continues the current cost recovery mechanism until the Commission establishes policies and rules to implement MEEIA, does not provide for timely cost recovery of energy efficiency expenditures and may even add additional delay. Let me be clear - if the Commission follows Staff's proposal, it will send a chilling message to the investor-owned utilities of Missouri. To my knowledge, the current Missouri mechanism is unprecedented in the lag it imposes on recovery of utility investments in energy efficiency. The Company did hold discussions on this issue, as my direct testimony indicated we would do. Staff's Report acknowledges the four settlement meetings which were held. These discussions were facilitated by the American Council for an Energy Efficient Economy (ACEEE) and the Regulatory Assistance Project (RAP), with financial support from the Robertson Foundation, rather than by AmerenUE. If settlement of this issue does not occur, then it is time for the Commission to act decisively and in this case, to support utility investments in energy efficiency. To do otherwise will cause considerable rethinking of AmerenUE's current short-term energy efficiency investment plans.

I then turn to a discussion of MIEC witness Maurice Brubaker's cost recovery proposal. Mr. Brubaker's testimony ignores the fact that the utility does not acquire physical assets when it invests in energy efficiency programs; to the contrary, the utility engages in a variety of marketing strategies and incurs expenses with the goal of altering our customers' purchases and consumption behavior. This obvious fact is why, to my knowledge, virtually every state allows utilities to expense energy efficiency program costs.

Next, I address MEG witness Billie Sue LaConte's interpretation of MEEIA and specifically of the opt out provision. As I explain, Ms. LaConte's interpretation does not consider all relevant factors and this issue should be left to the docket examining rate design issues and the rulemaking required by statute.

Finally, I discuss the appropriate level of rate case expense and the issue of whether EEI dues are appropriate to be recovered in the Company's revenue requirement.

II. ENERGY EFFICIENCY PROGRAM COST RECOVERY

Q. Is it in AmerenUE's interest to develop and implement energy efficiency programs for its customers?

A. Yes and no. On the positive side, we believe that the right kinds of energy efficiency programs, with the right marketing and promotional support, will increase customer satisfaction. We pay very close attention to the satisfaction of our customers, measuring it in 6 different surveys.[1] These surveys reveal which aspects of our products, services or brand image will return the greatest impact on customer satisfaction. In addition, many AmerenUE employees have incentive compensation tied to customer satisfaction, so in this sense customer energy efficiency programs are in our self-interest.

On the negative side, successful energy efficiency programs erode AmerenUE's revenue and earnings between rate cases and, under Missouri's current regulatory treatment, create huge regulatory asset balances as spending increases, as I discussed in my direct testimony.[2] These facts are significant disincentives to the utility that act to discourage its pursuit of energy efficiency.

Q. Are there any other strategic reasons why it might be beneficial, both to customers and shareholders, for AmerenUE to offer customer energy efficiency and demand response programs?

A. Yes, there are at least two. First, our customers and shareholders face large risks from carbon regulation, due to the fact that most of our generation is coal-

[1] These include: 1) The Customer Contact Index (CCI), which surveys 300 customers every month regarding their contact center experience; 2) The Field Operations CUstomer Survey (FOCUS), which surveys 500 customers each month concerning satisfaction with five types of customer service; 3) The Tree Trimming Survey, which surveys all property affected customers (approx. 1200 customers annually); 4) A

fired. Energy efficiency programs have potential value to everyone as a way to mitigate these risks. Also, pursuing energy efficiency and demand response now might delay the need for future additional generating capacity on our system. It's important that we understand energy efficiency's potential, so that we can reduce the cost and risk of meeting future demand for energy as much as possible.

Q. What studies has AmerenUE performed to assess the potential of energy efficiency and demand response programs on your system?

A. We have recently completed a comprehensive study of the potential impacts of energy efficiency and demand response, using information gained from surveying our own customers. To my knowledge this is the most comprehensive study of its kind ever performed in Missouri and one of the most advanced efforts of its kind in the nation.

I have attached the executive summary of the report to my testimony as Schedule SMK-ER2. Among the study's most important findings are these:

1. Between now and 2030, there is a realistic potential to offset 73% of anticipated load growth with energy efficiency and demand response. By "realistic" I mean programs that are economically feasible and attractive to customers. If we could increase spending to levels to reach the maximum achievable potential identified in the study, the offset would grow to 110%; in other words, the demand for electricity would remain flat, and perhaps slightly decline from today's level, over the next 20 years. This is <u>after</u>

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survey of overall customer satisfaction, which polls 900 customers every quarter; 5) The JD Power Residential Electric Survey; and 6) The JD Power Business Electric Survey.

[2] Kidwell Direct, pp 13-16.

taking into account anticipated increases in federal energy efficiency standards and other sources of “naturally occurring” efficiency.

2. In order to achieve the realistic potential level, annual spending on energy efficiency and demand response would need to increase from approximately $30 million annually today to around $100 million per year in 2015. This would be roughly 5% of annual revenues, which is in line with what the most aggressive utilities spend today. In order to reach maximum potential, annual spending would need to be at about twice this level, or $200+ million per year by 2015.

3. Our customers are more resistant to energy efficiency and demand response programs than customers in the West and Northeast. This is likely due to a combination of our low electricity rates and the fact that a large utility-sponsored energy efficiency program is a new idea in our service area that will take time to gain acceptance. Projected take rates for our programs are in the range of 20-30%, compared to 30-50% in other areas of the country. This means that at least in the beginning, it will be much more challenging (and expensive) to get our customers to engage and participate in energy efficiency and demand response programs.

It is clear from our research that there is great potential for energy efficiency and demand response programs to contribute to the Missouri economy, creating jobs and helping us all meet the challenges of climate change. It is also clear that success is not certain; it will be difficult and expensive to achieve the potential, though less expensive than the alternative (i.e. continued or increasing reliance on coal and natural gas). That's why it is important for Missouri to get the policy right – incentives must be properly aligned or we have no hope of achieving the benefits that more energy efficiency and demand response can bring.

Q. What role does MEEIA play in getting the policy right with respect to utility-sponsored energy efficiency?

A. The new law signed by Governor Nixon last summer establishes as state policy that utilities should be able to earn returns from energy efficiency and demand response investments equal to what they have historically earned from building power plants. As was stated in the Governor's press release at the time of the bill's signing:

> ***Senate Bill 376 sets a goal for Missouri's investor-owned electric utilities to achieve all cost-effective savings possible from energy efficiency programs. It provides the Public Service Commission with the ability to encourage cost-effective energy efficiency by making utility investments in energy efficiency programs for their customers at least as profitable as building new power plants or making capital investments.***[3]

If the Commission recognizes and chooses to exercise this ability, it will align utility business incentives with the aggressive pursuit of energy efficiency.

Q. Does the Commission Staff accept the idea of energy efficiency investments being as profitable to the utility as power plants?

A. I believe that Staff is trying to do so, but there are severe barriers contained in their position that, if allowed by this Commission to become state policy, will result in energy efficiency investments by Missouri utilities that are far below the level of "all cost-effective savings" envisioned by the Governor when he signed MEEIA.

Q. What are these barriers?

[3] Governor Nixon press release, "Gov. Nixon signs legislation encouraging energy efficiency to save utility customers money." July 13, 2009.

A. The first barrier concerns Staff's position on when the utility can begin recovering the costs of its programs in rates. The second barrier concerns the Staff's position on amortizing energy efficiency costs. These positions pose grave challenges to further AmerenUE investments in demand-side management (DSM) programs – today and in the future. In addition, even if these barriers are removed, AmerenUE still has no opportunity to earn returns on DSM investments that are equivalent to what it would expect to earn with a new power plant. I will address this issue later in my testimony.

Q. What is your understanding of Staff's position on when cost recovery in rates can begin?

A. Staff Witness Rogers states that such recovery can only begin after the completion of *ex-post* evaluation of each energy efficiency program.

Q. To your knowledge, does any other state have this requirement?

A. No.

Q. Why not?

A. In my opinion, few if any utilities would invest significant capital in energy efficiency programs on these terms. This is because utilities rightly view energy efficiency investments as being more risky than supply-side investments in some important ways. Building a "virtual power plant" from energy efficiency is nothing like building a real power plant. Utilities are familiar with the risks of building real power plants – we've been doing it for over 100 years. When the project is complete, the utility flips the switch; power flows, and the utility then owns an asset on its books and earns a return on that asset over its lifetime.

Investments in energy efficiency are very different. When a utility invests in energy efficiency, it incurs expenses in an attempt to change the consumption behavior of its customers. The utility has little experience in doing this; in the world outside utilities (and utility stakeholders), this is called marketing. Utilities are, by and large, not known today for their marketing prowess and neither are government agencies. This is changing, and must change if we are to be successful in achieving the benefits of energy efficiency for Missouri.

So in the pursuit of energy efficiency, the utility incurs a variety of marketing expenses: research and design of programs, promotional costs, customer incentives and evaluation costs, to name a few. It creates no assets for itself; customers buy the equipment and own the assets.

Staff's proposal seeks to treat energy efficiency investments exactly like power plants. An Allowance for Funds Used During Construction (AFUDC) is accrued until the "plant" goes "into service," which in Staff's mind is when the *ex-post facto* evaluation is complete. Assuming that customers, on average, behave as the utility planned they would for every program, the utility then gets to start earning its costs back over the "life" of the "asset," in Staff's methodology 10 years.

It is unfair to ask utility shareholders to wait 10 years (or more) for the return of expenses incurred for tariffed services approved by this Commission. As an Officer of AmerenUE, if Staff stands by its recommendation in this case, I would recommend that my Company defer most, if not all of our DSM expenses, at least until the Commission fully implements MEEIA through a formal rulemaking procedure.

I want to make one more point on this subject. Staff's position on this issue is tantamount to assuming imprudence of utility investments until proven otherwise. This seems to fly in the face of traditional regulatory practice in this state as I understand it.

Q. What is the Staff's position on the recovery period for DSM costs?

A. Staff is proposing that AmerenUE continue to recover its DSM costs over a 10-year amortization period. Staff has also included rate base treatment for the unamortized balance of AmerenUE's DSM expenses.

Q. Is Staff's rate base treatment of unamortized DSM expenses supportive to AmerenUE's efforts to pursue DSM?

A. Absolutely. While we are opposed to continuing the 10-year amortization period, for reasons I discuss below, AmerenUE appreciates the Staff's clarification on rate base treatment of unamortized DSM expenses.

Q. In the Staff Report, Staff witness John Rogers' states that "This analysis of DSM programs is analogous to how the addition of combustion turbines is analyzed." Please comment.

A. Earlier I discussed this barrier to achieving cost recovery of DSM investments. I will supplement my response with information from Mr. Rogers' deposition. Mr. Rogers understands that there are some very real differences between combustion turbines and DSM resources. Mr. Rogers states that a DSM resource, such as a compact fluorescent light bulb or CFL, produces energy savings immediately upon installation.[4] In this sense, a DSM resource is a virtual power plant that is used and useful upon installation. Mr. Rogers acknowledges that AmerenUE has sole responsibility for the operation of its combustion turbine generators (CTGs). Mr. Rogers also acknowledges that AmerenUE has no control over how customers install or operate various energy efficiency measures.[5] Mr. Rogers believes that a CTG is determined cost effective through the integrated resource planning process. Yet, even though DSM resources must go through the same cost effectiveness testing in the integrated resource planning process, Mr. Rogers states that it will take more time for DSM resources to be determined cost effective post installation or outside of the integrated resource planning analysis process. (Deposition page 136, lines 3-25, page 137, lines 1-2).

Q. Does it appear that Staff may be giving preference to supply side resources such as CTGs over DSM resources?

A. Yes. Based on the DSM cost recovery of Staff supplemented by Mr. Rogers deposition on the same issue, Staff understands that a CTG is very different than a DSM resource. Staff is very willing to develop processes and procedures to ascertain that new CTG additions are used and useful. On the other hand, Staff seems reluctant to do the same for DSM resources.

Q. Why is the Staff's position on amortization of DSM costs a barrier to utility energy efficiency investments?

A. Because the current recovery mechanism results in extreme regulatory lag in recovering our DSM expenses. We are aware of no other jurisdiction which imposes a lag on energy efficiency expenses anywhere close to Missouri's current policy. As AmerenUE Witness Matt Michels discusses in his rebuttal testimony, under Staff's cost recovery proposal, the regulatory asset for unrecovered DSM program costs grows to a

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[4] Rogers Deposition, p. 133, l. 23 through p. 134, l. 9.
[5] Rogers Deposition, p. 137, l. 3-16.

balance of approximately $481 million by the end of 2018. No party in this case has disputed the fact that the DSM regulatory asset will grow to hundreds of millions of dollars under Staff's current methodology. Given the additional fact that AmerenUE's success in DSM depends on changing the ingrained energy consumption behavior of thousands of individuals and businesses, the Commission should appreciate the Company's reluctance to incur this level of regulatory risk. This is one important reason why most other Commissions permit utilities to expense DSM costs and many allow recovery outside full rate case proceedings, as I will discuss later in my testimony.

Q. In Staff's Report, referring to your direct testimony, Witness Rogers states that "while AmerenUE's proposal is a starting point for discussion, many details of its proposal need to be clarified or determined." Are you providing additional details in your rebuttal testimony as a response?

A. Yes, I am.

Q. Please describe the forecast expense tracker cost recovery mechanism proposed by AmerenUE.

A. The forecast expense tracker seeks to recover DSM program expenses essentially as they occur by including in the utility's rates a forecast average expense amount and then tracking the differences between that amount and actual expenses incurred and capturing those differences in a regulatory asset for future recovery from, or reimbursement to, customers. AmerenUE is proposing that the average of a two-year forecast of expenses be used to set the annual expense recovery amount and that the balance of any regulatory asset be amortized over three years, beginning with the effective date of new rates as set in the Company's subsequent general rate case. The regulatory asset would include the carrying costs, or credit, associated with amounts recorded to the regulatory asset balance at the Company's AFUDC rate until amortization of such costs begins. Once amortization commences, interest at AmerenUE's most recent allowed return on rate base would be applied to the unamortized balance associated with the costs being amortized. Examples of the calculations needed to determine the forecast expense and expense true-up amounts are attached as Schedule SMK-ER3.

Q. Why is an expense tracker appropriate for recovering these costs?

A. An expense tracker is the most appropriate way to recover DSM expenses. There are three important reasons which justify this expense treatment. First, the costs involved are indeed expenses, as I explained earlier in my testimony. Second, expensing of DSM costs is the method used by most jurisdictions, as I discuss below. Third, if AmerenUE is to pursue aggressive deployment of DSM programs, then our annual costs will increase substantially in the next few years. Mitigating the earnings erosion of regulatory lag between cases would send a clear message of support from the Commission for our efforts.

Q. Is AmerenUE proposing an incentive mechanism for DSM investments in this case?

A. No. As I stated in my direct testimony, more experience with programs and dialogue with stakeholders is necessary before we can make a specific proposal. However, the issue must be addressed before the objectives of MEEIA can be achieved.

Q. Does AmerenUE's cost recovery proposal fully meet the policy objective of MEEIA, as expressed in the Governor's press release quoted earlier in your testimony?

A. No, it does not. As AmerenUE Witness Matt Michels states in his rebuttal testimony, appropriately expensing DSM program costs is not sufficient to produce the same level of earnings and return on equity (ROE) with implementation of DSM as is available to AmerenUE without DSM. His analysis shows that AmerenUE's earnings through 2018 are expected to be approximately $70 million dollars lower, on a present value basis, if we pursue the DSM programs contained in our most recent Integrated Resource Plan (IRP). This situation clearly does not meet the policy objective of MEEIA.

Q. Should AmerenUE's proposal be considered a mainstream approach?

A. Yes.

Q. Please explain.

A. I will cite several national references. The first reference is the National Action Plan for Energy Efficiency (NAPEE) guide, "Aligning Utility Incentives with Investments in Energy Efficiency". Table 1-2 shows DSM cost recovery mechanisms by state as of September 2007. The majority of states have contemporaneous cost recovery and/or either decoupling and/or lost revenue recovery and/or performance incentives. The NAPEE Guide is attached to my testimony as Schedule SMK-ER4.

Q. Are there other national references on DSM cost recovery mechanisms?

A. Yes. The Edison Electric Institute published its state regulatory frameworks research in December 2009. The EEI research is attached to my testimony as Schedule SMK-ER5. The EEI research shows that in the time between 2007 and 2009 even more states have been added to the list that have established regulatory frameworks to provide the opportunity for contemporaneous cost recovery, lost revenue recovery, and performance incentives.

Q. Are there any other national references that you would like to cite to show that AmerenUE's DSM cost recovery proposal is mainstream relative to other states?

A. Yes. The Regulatory Assistance Project (RAP) developed a presentation dated November 20, 2009 that discusses energy efficiency incentives for utilities across the nation. The RAP presentation is attached to my testimony as Schedule SMK-ER6. Although the RAP presentation is primarily a primer on incentive mechanisms, the presentation includes several examples of states that generally follow the DSM cost recovery approach supported by AmerenUE.

III. AMERENUE'S LIGHTING AND APPLIANCE PROGRAM

Q. In Staff's Report, John Rogers expressed concern that the Lighting and Appliance program is very risky because the program's design had never been implemented by a single utility that operates in a portion of a state, rather the program has been only implemented throughout a state or region of the country. Do you agree with this assessment?

A. No. According to the 2009 ENERGY STAR Summary of Lighting Programs, the following utilities offer buy-downs and mark-downs on CFLs similar to the AmerenUE program:

Long Island Power Authority (LIPA)
NV Energy (Formerly Nevada Power and Sierra Pacific Power)
Pacificorp (Rocky Mountain Power and Pacific Power)
Pacific Gas & Electric
San Diego Gas & Electric
Southern California Edison
Baltimore Gas & Electric
PEPCO
Dominion
Ameren Illinois Utilities
ComEd
Dayton Power & Light
Connecticut Light & Power
United Illuminating
National Grid Massachusetts
National Grid Rhode Island
Idaho Power Company
Puget Sound Energy
Entergy
Arizona Public Service
Tucson Electric Power
El Paso Electric
Public Service of New Mexico

Q. What type of understanding does Mr. Rogers have as to the extent and nature of market transformation programs conducted on a statewide basis?

A. Although Mr. Rogers has some understanding, it became clear in his deposition that there are some informational gaps. Mr. Rogers claimed that he is aware of two state-wide market transformation programs. The first is the Northwest Energy Efficiency Alliance (NEEA). The second program he named is New York Energy Smart. Mr. Rogers stated that all the programs within each of these multi-jurisdictional entities were one program and he relies on that fact as the basis for his “concern” with

AmerenUE's program not being offered statewide.[6] Mr. Rogers is misinformed about the facts. The fact is that there are five investor owned utilities in NEEA. They are:

- Avista Utilities
- Idaho Power Company
- Northwestern Energy
- PacifiCorp
- Puget Sound Energy

Each utility has different incentive levels for different retail partners for their individual lighting and appliance programs. Program delivery also varies with several of the utilities using direct rebates. Some programs have limits on the minimum and maximum number of CFLs that may be eligible for rebates. New York Energy Smart is a program offered by The New York State Energy Research and Development Authority (NYSERDA). NYSERDA is not a consortium of municipal, cooperative and investor owned utilities. NYSERDA is a public benefit corporation that is funded by state ratepayers through a system benefits charge. Investor owned utilities in New York do not have lighting and appliance programs.

Q In your prior list of utilities with lighting and appliance market transformation programs, are all of those state-wide programs?

A. Many of the programs listed above include several utilities located in the same state and some may work together in consortiums. However, none of these programs is truly state-wide. All areas will have pockets where homes are served by cooperatives or municipals and not the regulated electric utility. In addition, adjacent utilities may not run exactly the same programs. For example, the Ameren Illinois Utilities and Commonwealth Edison both run lighting market transformation programs.

[6] Rogers deposition, p. 44, l. 23 through p. 46, l. 23.

However, the Commonwealth Edison program includes grocery chains and Walmart, while the Ameren Illinois program does not. The Ameren Illinois program shows the discount available on bulbs at each participating retailer on its website, while the Commonwealth Edison program simply lists participating retailers. Both have online stores, but the Ameren Illinois Utilities store only offers CFLs. The Commonwealth Edison online store offers a wide range of products including light fixtures, insulation and thermostats. The same 15W Harmony Lightwiz mini-spiral that costs $1 with free shipping on the Ameren Illinois Utilities website, costs $3.25 on Commonwealth Edison's website plus shipping costs.

Q. Mr. Rogers goes on to state that the impacts of market transformation programs are very difficult to measure. Do you agree?

A. No. AmerenUE and The Cadmus Group (Cadmus), the independent evaluator of the Residential Energy Efficiency Portfolio, believe that the impacts of market transformation programs are measured differently than traditional rebate programs, but are not necessarily more difficult to measure. Their methodology is not new, is considered best practice, and is used by similar programs in New York, Massachusetts, and California.

Q. Is Mr. Rogers' concern over the difficulty of measuring the impact of market transformation programs consistent with the discussion of this issue in his deposition?

A. No, it was not. In Mr. Rogers' portion of the Staff Report, he listed his concern with the difficulty in measuring the impact of market transformation programs. In Mr. Rogers' deposition, he stated that the approach being followed by AmerenUE's residential program evaluation contractor, Cadmus, is "probably the only or the best way to measure the impact of the [Lighting & Appliance] program.[7] Mr. Rogers thinks that AmerenUE's evaluation contractor is following the best approach to evaluate the program. Finally, Mr. Rogers admitted he had no recommendations on how to improve the evaluation process.

Q. Please describe the current best practice evaluation approach for market transformation programs being implemented by Cadmus and AmerenUE.

A. Cadmus has attended two quarterly meetings with stakeholders to present their evaluation approach. The following is an excerpt from their evaluation plan for the Lighting and Appliance program:

> *An upstream market transformation program such as AmerenUE's Lighting and Appliances Program does not offer direct incentives to residential end-use customers. In fact, because the Program's efforts are primarily focused on retailer training and increasing the in-store availability of ENERGY STAR lighting and appliances, the Program itself may be somewhat transparent to those actually purchasing incentivized efficiency measures. As a result, implementing a self-reported net-to-gross evaluation approach (i.e., direct solicitation of AmerenUE customers regarding what they would have done in absence of the Program) is not the most appropriate strategy. Further, because upstream programs work with multiple market actors and include wide-reaching marketing campaigns promoting energy efficiency to the general public, they tend to stimulate freedrivership/spillover or "market effects". A standard self-report net-to-gross (NTG) approach using only AmerenUE customers purchasing CFLs would not capture these effects and therefore may understate the true impact of the Program.*

Given all of these factors, Cadmus will employ a market-based evaluation approach to measure the Program's impact on the market for ENERGY STAR qualified CFLs within AmerenUE's service territory. A market-based evaluation approach, which assesses changes in the market for ENERGY STAR CFLs <u>as a whole</u>, rather than

[7] Rogers deposition, p. 63, ll. 8-10).

evaluating and aggregating the individual decision-making processes of specific CFL purchasers, is the most appropriate and most often employed evaluation method for assessing market transformation programs. Evaluating total market change will capture any "market effects" generated by AmerenUE's efforts.

Q. How will Cadmus' approach account for the argument that CFL sales have been on the increase simply due to naturally occurring energy efficiency?

A. In Cadmus' effort to evaluate the Program and determine the net energy savings associated with it, it is important to quantify both the portion of the observed market change generated by natural market forces and that attributable to AmerenUE's program. To do this, the market-based evaluation approach compares the change in product sales from other service territories *not* implementing a utility efficiency program similar to that of AmerenUE. By observing the market change in areas experiencing naturally occurring market forces (federal campaigns, retailer promotions, etc.) but not a utility program, Cadmus can estimate the market change likely to have occurred in AmerenUE's territory had the program **not** been implemented. Subtracting the estimated level of naturally occurring sales from the total sales determined in AmerenUE's service territory reveals the sales attributable to the program itself. In summary, market-based evaluation focuses on estimating the sales that are *incremental* to these other efforts and a direct result of a utility's intervention in the market.

Q. Staff has expressed concerns over identifying and quantifying "leakage" that may be associated with the Lighting and Appliance program. What is "leakage"?

A. "Leakage" refers to program benefits that may be received by customers outside the utilities' service area. An example of leakage is that a customer of a cooperative electric utility located in close proximity to the AmerenUE service territory who may purchase a discounted CFL at an AmerenUE partner retail store within the AmerenUE service territory. Because leakage was a specific concern expressed by Staff in quarterly meetings, Cadmus increased the number of customer intercepts they will use to assess leakage in excess of 95% confidence and 5% precision. AmerenUE continues to remain flexible and is willing to address any specific concerns Staff has on the evaluation of any of our residential energy efficiency programs.

Q. What was Mr. Rogers' deposition position on the issue of leakage?

A. Mr. Rogers expressed concern that AmerenUE's service territory is intertwined with those of municipal and cooperative systems. Therefore, the opportunity exists for a non-AmerenUE customer to receive benefits from an AmerenUE sponsored energy efficiency incentive program at a retail store located near the boundaries of service territories.[8]

Q. How valid is Mr. Rogers' concern?

A. Mr. Rogers dismissed his concerns over leakage in his deposition. When asked if the entire State of Missouri implemented the program, would there be leakage to states surrounding Missouri, Mr. Rogers stated that there would be. Ultimately, Mr. Rogers agreed that the only way to completely stop leakage is for the entire nation to implement the program.[9]

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[8] Rogers deposition, p. 48, ll. 21-25.
[9] Rogers deposition, p. 53, ll. 1-25.

Q. Mr. Rogers also states that AmerenUE has not provided the Staff with any meaningful quarterly progress reports on the Lighting and Appliance program. Do you agree with this statement?

A. No. AmerenUE has held quarterly meetings with Staff and other stakeholders to provide updates on all energy efficiency and demand response programs. Updates on the Lighting and Appliance program were provided at every meeting. However, these updates have not historically included energy savings and budget results, for two reasons. First, the nature of the promotions meant that sales results were not reported by retailers and manufacturers until after the first program year ended. The first program year was scheduled to end September 30, 2009 and was extended until December 31, 2009 to ease the transition from Lockheed Martin (AmerenUE's former program administrator) to Applied Proactive Technologies (the current program administrator). Consequently, Program Year 1 results were not available until the quarterly meeting held in February 2010. Second, AmerenUE was in settlement negotiations over its contract dispute with Lockheed Martin and did not know final program costs until a settlement was reached in November 2010. Therefore, program costs could also not be reported until the February 2010 meeting.

Q. Will there be changes to the frequency of program reporting going forward?

A. Yes. Going forward, AmerenUE will report program impacts and costs to stakeholders at regularly scheduled quarterly update meetings. Mr. Rogers created a spreadsheet to be used as a "scorecard" to keep track of progress on all AmerenUE energy efficiency and demand response programs, and AmerenUE has committed to updating this scorecard at each quarterly meeting.

Q. Mr. Rogers also recommended that the cost of the Lighting and Appliance program remain in the regulatory asset account until evaluation is complete in two to three years. Do you agree?

A. Absolutely not. The costs for the Lighting and Appliance program incurred to date should be included in rate base immediately. AmerenUE has received all of the sales reports for the original Program Year 1. In the future, sales data will be provided to AmerenUE on a monthly basis. AmerenUE is tracking program sales in a database which calculates program megawatt-hour (MWH) savings based on stipulated values for wattage differential with comparable incandescent bulbs and average burn hours. The calculated MWH savings also use a conservative net-to-gross ratio of 80%. It is common for programs to use stipulated values to calculate energy savings. The savings are then trued up after the evaluation is complete. For AmerenUE programs, this true-up is an annual process. The first Evaluation Report on the Lighting and Appliance program is due March 31, 2010. Subsequent annual reports are due March 31, 2011 and March 31, 2012. Mr. Rogers appears to be referring to the final report on all three project years which is due June 30, 2012. However, this final report is a summary of the three annual reports. Each annual report will include impact analyses and report net kilowatt-hour (kWh) savings and Total Resource Cost (TRC) test results from the prior Program Year.

Beyond the fact that there is no need to wait three years to start recovery of these costs, such regulatory treatment further increases regulatory lag and provides a strong disincentive for AmerenUE, or any utility, to pursue energy efficiency programs, especially any program that is innovative with respect to current practice in Missouri.

Q. Do you agree with Mr. Rogers that the Lighting and Appliance program has a relatively low benefit to AmerenUE's residential ratepayers?

A: No. All of AmerenUE's energy efficiency programs must pass cost-benefit tests in the Integrated Resource Planning process. The Total Resource Cost test is recalculated based upon final program designs. These calculations are shared with Staff prior to filing program tariffs. The most recent TRC provided for the Lighting and Appliance program is 3.57, which is higher than the original TRC for the Lighting and Appliance Program from the Integrated Resource Plan, which was 2.29. In fact, it is higher than any of the TRC results originally anticipated for any residential program in the Integrated Resource Plan. In addition, the Lighting and Appliance Program also provides the greatest MWH savings of all of the programs planned for the residential portfolio, accounting for over half of the portfolio savings.

IV. IMPLEMENTATION OF AMERENUE'S DSM PROGRAMS

Q. In Staff's Report, Staff Witness Adam McKinnie states, "Of the fifteen demand-side programs in AmerenUE's Electric Resource Planning filing on February 5, 2008, only eight have been implemented and all eight were implemented later than designated in the implementation plan by from 5 months to 10 months." Is this true?

A. It is true that our DSM programs have been implemented later than originally expected. It is also true that the programs already in the field represent 89% of our overall goal for DSM established in our last IRP, measured by savings expected in the third year of implementation. So, while some programs have not yet been implemented, the programs now in the field are targeting the vast majority of the savings potential identified in AmerenUE's last IRP.

Q. Why were the programs implemented later than originally planned?

A. AmerenUE believes that DSM programs are our most cost-effective resource for meeting future consumer demand at least cost, but implementing our programs has proved more challenging than we anticipated when we filed our IRP. The most important challenge, which was not fully factored into the IRP implementation plan, was the time to acquire resources to design and implement full-scale DSM programs. While speed to market is important, managing the risks of starting up such a large new initiative is much more important. AmerenUE sought to mitigate startup risks, to customers as well as shareholders, by outsourcing most of the labor for implementing our DSM programs. During restructuring over the last 10-15 years, AmerenUE eliminated most of its internal marketing capability. Today, most of the labor associated with our programs is outsourced. Given the lack of required internal experience, our lowest-risk course, and the fastest way we could get programs into the field at a large scale, was to rely on outsourcing.

Q. Describe the process that AmerenUE used to select its DSM program prime contractors for program implementation.

A. The first step in the process was to engage a national DSM consulting firm to assist in the development, administration and evaluation of a comprehensive request for proposals (RFP) to engage contractors to administer AmerenUE DSM programs outlined in the AmerenUE 2008 IRP filing.

Q. What consulting firm did AmerenUE engage?

A. AmerenUE engaged Summit Blue Consulting on December 21, 2007. Note that this was <u>before</u> AmerenUE filed its most recent IRP.

Q. Describe the decision making process for selecting Summit Blue.

A. An RFP was issued and Summit Blue was selected on the basis of the quality of their bid relative to other bidders.

Q. Describe the scope of work assigned to Summit Blue.

A. Summit Blue worked with AmerenUE to develop a comprehensive RFP to solicit a prime contractor(s) to implement the AmerenUE residential and business portfolios of DSM programs. Summit Blue developed a website to both post and answer any and all questions from potential bidders to the RFP. Summit Blue independently administered the RFP and assisted in the evaluation of bids to the RFP.

Q. When was the DSM program implementation RFP issued and when were contracts awarded to the successful bidders?

A. The RFP was issued on February 25, 2008. A final contract, with a negotiated statement of work, was finalized with Lockheed Martin on August 14, 2008.

Q. Is 6 months a reasonable amount of time for negotiating these contracts?

A. Yes. We followed our internal contracting procedures and added additional legal reviews, since this was the first time that AmerenUE had entered into contracts of this type. For the first time through such a process, 6 months is reasonable. I would expect to improve on this substantially the next time such contracts are negotiated.

Q. Describe the process that AmerenUE used to select its DSM program prime contractors for program evaluation.

A. Similar to how AmerenUE developed its RFP to select a program implementation contractor, AmerenUE engaged an expert evaluation, measurement, and verification (EM&V) contractor to assist in the development, administration, and evaluation of the RFP.

Q. Who was the EM&V contractor selected by AmerenUE?

A. Schiller Consulting was selected. Steven R. Schiller served as the project manager and primary author of the National Action Plan For Energy Efficiency "Model Energy Efficiency Program Impact Evaluation Guide."

Q. Discuss the scope and schedule associated with Mr. Schiller's work.

A. A statement of work was finalized with Mr. Schiller on March 8, 2008. The RFP to elicit bids from EM&V contractors was released on April 25, 2008. Statements of work with the successful EM&V contractors, Cadmus Group for the residential portfolio and ADM for the business portfolio, were finalized on September 9, 2008.

Q. When were the first AmerenUE DSM programs offered to customers?

A. The first business DSM programs were offered on February 11, 2009.

Q. What caused the delay in implementing programs?

A. The primary reason was that Ameren senior management placed a hold on most ongoing projects during the fourth quarter of 2008, due to financial pressures. While we continued program design and tariff development, offering the programs to customers was delayed until the first quarter of 2009.

Q. What are AmerenUE's plans for implementing the remaining DSM programs in its IRP portfolio?

A. AmerenUE's plans for the existing and any additional DSM programs are dependent on the outcome of the Commission's decision on DSM cost recovery in this case. AmerenUE is currently designing the next two residential programs to compliment our existing three programs. AmerenUE will monitor the rate case as it proceeds and will be prepared to roll out these important programs during the second quarter of 2009.

V. MIEC'S POSITION ON DSM COST RECOVERY

Q. Are you familiar with the Direct Testimony of MIEC witness Maurice Brubaker?

A. Yes, I am. Among other issues, Mr. Brubaker presents MIEC's position on cost recovery of the utility's DSM expenses.

Q. In summary, what is Mr. Brubaker's position on recovery of DSM expenses?

A. Mr. Brubaker is in essential agreement with Staff's position, namely amortization over a 10-year period.

Q. So your testimony concerning Staff's position on this issue applies equally to Mr. Brubaker's position, is that correct?

A. Yes. I disagree with Mr. Brubaker's arguments and analysis for the same reasons that I disagree with Staff.

Q. In his direct testimony, Mr. Brubaker states, "Just as depreciation over the expected life of an asset is the norm for supply-side resources, amortization

of the regulatory asset over the life of the related demand-side measure is the appropriate recovery period for demand-side resources." Do you agree?

A. Absolutely not. Like many other regulatory assets that are currently on AmerenUE's books, our DSM costs are expenses that are being accrued into a regulatory asset for later adjudication in a rate case. The assumed economic life of appliances purchased by our customers is irrelevant; the utility's costs are expenses, as I have demonstrated earlier in my testimony.

In some instances, in order to spread out highly volatile expenses, like storm costs, the Commission uses amortization. This is not the case for AmerenUE's DSM expenses; if a supportive regulatory framework is established in Missouri, our DSM costs will steadily increase over the next few years. Adopting the cost recovery mechanism I have proposed in my testimony would begin establishing this framework and encourage Missouri utilities to pursue energy efficiency resources.

Q. Mr. Brubaker discusses identifying the dollar amounts associated with AmerenUE's DSM programs and determining a credit for those customers who opt out as allowed for under MEEIA. Would you address his comments?

A. MEG witness Billie Sue LaConte makes much the same argument, in a bit more detail, and I will address that issue below.

VI. MEG'S POSITION ON DSM COST RECOVERY

Q. Are you familiar with the direct testimony of MEG witness Billie Sue LaConte?

A. Yes. Ms. LaConte's testimony is focused upon energy efficiency and MEEIA. She makes two points; first she provides a calculation of how AmerenUE could separate energy efficiency costs from the other costs. Secondly, she discusses the ability of certain customers to "opt out" of energy efficiency costs as provided for under MEEIA.

Q. Is the methodology proposed by Ms. LaConte sufficient to separate energy efficiency costs?

A. No. Ms. LaConte's methodology looks only at the dollar costs of energy efficiency measures. Of course, there are offsetting benefits to those costs, which must also be factor. If it is true that energy efficiency is a low cost resource, then when a customer opts out, they are in essence, opting into higher cost resources. It is even possible that customers who opt out could end up paying higher rates than those customers who do not. The calculation provided by Ms. LaConte simply does not capture all relevant factors and should not be adopted at this time. However, while this is likely not a simple calculation, AmerenUE agrees it is a calculation that needs to be completed, perhaps in File No. EW-2010-0187 and/or the subsequent rulemaking required by MEEIA. I do not believe it is necessary for the Commission to set forth the calculation in this case.

Finally, I would point out that MEEIA contains an explicit restriction on the Commission adopting a rate design modification prior to completing a docket to study this matter and completion of a rulemaking. As neither has yet occurred, the Company cannot, at this time, effectuate a rate design modification to implement the opt out provision of MEEIA. The removal of DSM costs for customers who opt out would require a modification to AmerenUE's rate design – either by creating new rates or classes for customers that opt out or designing some type of crediting mechanism. As such, the statements of both Mr. Brubaker and Ms. LaConte on this issue are premature.

Q. Please address Ms. LaConte's discussion of how the "opt out" portion of MEEIA works.

A. Ms. LaConte points out that MEEIA allows customers who opt out to still participate in interruptible or curtailable programs. I do not disagree with that statement. However, she labels Rider L and Rider M as curtailable programs and asserts that her clients that opt out may still participate in these programs. I believe this to be an incorrect reading of MEEIA. While I agree that MEEIA allows customers who opt out to participate in interruptible or curtailable programs, it categorizes interruptible or curtailable as a subpart of demand-side programs, along with demand response programs. This indicates interruptible or curtailable programs are different from demand response programs. Accordingly, I do not believe a customer who opts out under MEEIA is allowed to participate in demand response programs.

There are two very different types of these programs. The first type is controllable, in which the utility exercises control of when the customer curtails load. Typically, the customer pays a lower rate for electric service because the service may be interrupted. The customer is told when to interrupt by the utility and there may be financial consequences to the customer if the customer does not comply with a curtailment call by the utility. This type of a program also typically requires the customer to set an assurance power level, which becomes the maximum amount of service the customer may take during a curtailment call without incurring a penalty. AmerenUE does not have any curtailable or interruptible tariffs at this time.

The second program type is demand response. In this type of a program, the customer decides when load is reduced. A curtailment is not called by the utility. Instead, price signals are used as an incentive for the customer to reduce load. If the price offered is sufficient to induce the customer to act, i.e., reduce load, the customer will receive payment at an agreed upon price for reducing load. If the customer does not reduce load, there is no penalty assessed nor is there an impact on the rate the customer pays. Price responsive programs empower customers to choose the level of risk that best suits them.

Rider L and Rider M are both demand response programs. Rider L is explicitly a demand response program. It offers customers a price that includes a long run capacity price component in addition to the traditional market energy price component, but it contains no requirement to reduce load nor does it impose a penalty if a customer does not reduce its load. Rider M predates MEEIA and so does contain the language “curtailment.” However, when one reads the tariff, it is apparent this tariff is not one under which AmerenUE controls when service to a customer is curtailed. Rider M is not properly classified as a curtailable tariff as the terms are used by MEEIA. Because neither Rider L nor Rider M are curtailable or interruptible programs, a customer who opts out is ineligible to participate in either tariff.

VII. RATE CASE EXPENSE

Q. Staff has recommended that $1,000,000 be included in AmerenUE’s revenue requirement for rate case expenses. Do you agree with its recommendation?

A. No, I do not. Calling it a survey of Missouri utilities, Ms. Ferguson looked at how much had been allowed for the rate cases of Kansas City Power & Light's (KCPL), KCP&L Greater Missouri Operations Company and the steam operations of KCP&L Greater Missouri Operations Company. Using that dollar amount, Ms. Ferguson made the arbitrary recommendation that AmerenUE's external rate case costs be capped at $1 million.

Ms. Ferguson does not point to any cost of AmerenUE as imprudent or give any other reason why any portion of AmerenUE's rate case expenses should not be recovered. This certainly isn't supported by the long tradition of regulation in Missouri, which obligates the Commission to provide the utilities it regulates with a reasonable opportunity to recover prudently incurred costs. The Commission does not look at the cost to operate a baseload coal plant of KCPL and use that fact to determine the appropriate cost for AmerenUE to operate one of its baseload coal plants. If expenses are properly incurred, they must be allowed as a part of rates. AmerenUE believes this principle lies at the heart of sound utility regulation, is good public policy and sees no reason to depart from this long held tradition.

Ms. Ferguson's survey does not take into account the many differences between an AmerenUE rate case and KCPL's. Her argument ignores that AmerenUE is by far the largest utility in Missouri (KCPL's Missouri and Kansas customers number just under half as many as AmerenUE) and that its rate case filings involve large sums and many complex issues, and include numerous intervening parties. AmerenUE's current rate request is for an increase of $402 million. The three KCPL cases surveyed by Staff in total requested an overall increase of $185.9 million. Another example of the difference is the very large number of local public hearings that were held in this and in the last AmerenUE rate case – 17 (plus an all day "listening post") in this rate case, and almost as many in the last rate case. This compares to a more normal level of local public hearings in the KCPL cases cited by Staff which had a total of four public hearings. AmerenUE rate cases also attracted numerous intervenors, many of which are active participants throughout the entire case.

Q. Has AmerenUE's utilization of external resources for rate case support been dropping in recent years?

A. Yes, it has. Since I assumed responsibility for AmerenUE's state regulatory affairs in October 2007, we have reduced the use of external experts in preparing and defending our rate cases. This not only benefits our customers; it is building important internal expertise.

The following table shows our actual rate case expenses for the last two cases and our estimated expenses for this case:

	ER-2007-0002 Actual	ER-2008-0318 Actual	ER-2010-0036 Estimated
Outside Legal	$1,147,557	$ 600,737	$ 685,000
External Consultants	$2,411,420	$1,309,810	$1,350,000
Other	$ 370,465	$ 170,531	$ 85,000
Total	$3,929,442	$2,081,078	$2,120,000

AmerenUE has decreased its reliance on outside consultants, reduced the number of external witnesses and otherwise taken steps to reduce its rate case expense over the last few years. However, even with this diligent effort, the importance of rate cases to the well being of the Company and the number and complexity of issues involved make it impossible to fully prosecute this case without the outside assistance AmerenUE has used.

Q. OPC makes an even more aggressive recommendation, arguing that certain costs only benefit shareholders and so shouldn't be allowed at all and that the remaining, prudent expenditures should be shared between customers and shareholders. How do you respond?

A. Mr. Trippensee's argument is based upon pure assertion rather than anything the Commission could rely upon in this case. He argues that AmerenUE should be able to prepare and prosecute a rate case with internal labor, citing the number of attorneys and other internal experts that the Company has in house. Mr. Trippensee does not back his claims with facts. For example, Mr. Trippensee asserts that AmerenUE shouldn't need external attorneys as it has attorneys in house with regulatory experience. He attaches a data request response which indicates the Company and/or its affiliates employee nine attorneys with "regulatory experience." What Mr. Trippensee fails to recognize is those attorneys, with the exception of Thomas Byrne and Wendy Tatro, already have full time jobs representing the Company or an affiliate in front of another regulatory agency. Some do regulatory work for AmerenUE's Illinois affiliates at the Illinois Commerce Commission, some at the Federal Energy Regulatory Commission, some at the Nuclear Regulatory Commission, some at the Environmental Protection Agency, etc. In fact, OPC, Staff and the Commission are all aware that Mr. Lowery represents AmerenUE in many regulatory matters in front of the Commission, even outside of a rate case. Additional attorneys are hired as needed and that need increases during rate cases due to the amount of legal work involved.

Much the same is true for the external experts hired by AmerenUE. While the Company probably could find someone internally to file return on equity testimony, that person already has a full time job that is important to the Company. One example is the oft-repeated notion that there are at least three individuals who have filed cost of capital testimony. Mr. Birdsong, one of the three listed, is Treasurer and is certainly otherwise occupied with dealing with Company financings, which are necessary to provide service to our customers at just and reasonable rates. Mr. O'Bryan, yet another of the named three, has provided testimony on AmerenUE's capital structure and cost of debt, but not on ROE.

Q. Does Mr. Trippensee make any other unsubstantiated assertions or recommendations to which you'd like to respond?

A. He does. He claims that costs which primarily benefit shareholders should not be recoverable and then goes on to allege that ROE testimony only benefits shareholders. This reasoning reveals a fundamental misunderstanding of the purpose of ROE testimony. In the much quoted *Bluefield* case, the Supreme Court stated, "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties…"[10] Further, as explained in the direct testimony of AmerenUE witness Warner Baxter, it is better for customers to be served by a utility that has a reasonable opportunity to recover its costs and earn a fair return on investment, as it improves cash flows, enhances credit ratings and provides access to capital at a lower long-term cost.

[10] *Bluefield Water Works & Improvement Co. v. PSC of the State of W.Va., et al.*, 262 U.S. 679, 692 (1923).

Mr. Trippensee also recommends splitting prudent expenditures 50/50 between shareholders and customers. As I stated above, the Commission has an obligation to provide the utilities it regulates with a reasonable opportunity to recover prudently incurred costs. Mr. Trippensee's recommendation to split prudent expenditures 50/50 violates this very important principle.

VII. EEI DUES

Q. Staff witness Lisa Ferguson recommended disallowance of all fees related to AmerenUE's membership in EEI, arguing that EEI's role is one of legislative and regulatory lobbying. Is this an accurate characterization?

A. No, it is not. And I think the Commission has historically recognized that there may be a customer benefit to EEI, as reflected in two KCPL rate cases. However, the Commission indicated there needed to be a better quantification or explanation of that benefit to customers. It does not appear that the Commission has made a definitive statement on this cost.

Q. Do you believe AmerenUE's customers benefit from AmerenUE's membership in EEI?

A. Absolutely they do. Some recent EEI activities that benefit AmerenUE ratepayers include EEI's leadership role in developing climate change points of agreement within its membership and in communicating industry views to policymakers. EEI has organized activities with key stakeholders to support climate change legislation that protects the environment and electricity consumers. In this regard, EEI is working with NARUC, the National Governors Association, the National Conference of State Legislators, the National Association of Counties and others. EEI has also launched a new campaign and Website (www.SmartClimatePolicy.org) to educate stakeholders and stimulate thoughtful interaction. As the legislation winds its way through the Senate, EEI continues this work with a particular focus on helping to reduce consumer cost increases. This past summer, EEI organized a series of CEO meetings that resulted in visits with 32 senators.

EEI is also working to keep members informed and involved in the American Recovery and Reinvestment Act (ARRA) implementation, including notifying members of ARRA-related funding opportunities such as smart grid, energy efficiency, conservation and renewable programs. To that end, EEI has created a Stimulus Implementation Internet Workroom with 500 member company participants and is working with stakeholders to respond to numerous initiatives from FERC and DOE in implementing ARRA provisions.

EEI is currently working with member companies and various Congressional committees in crafting legislation to address cyber attacks against the electric power grid and to identify vulnerabilities that could be exploited. EEI representatives recently testified before Congress on industry efforts to secure the electric grid against physical and cyber attacks.

Another significant issue facing electric utilities is derivatives reform. EEI is working on both legislative and regulatory fronts to shape effective derivatives reform that preserves the OTC derivatives market for utilities and other end users. Derivative reform legislation or regulation could cost AmerenUE millions of dollars if it requires AmerenUE to trade on exchanges for which it would have to pay exchange fees and incur higher collateral requirements for its hedging activities thus negatively impacting customers.

On the federal regulatory front, EEI has worked with its member companies to develop coordinated responses in support of FERC's proposed policy statement and action plan on smart grid devices and systems. EEI and its member companies continue to encourage FERC to work closely with NIST in support of the development of interoperability standards.

EEI has developed an online compliance training module to assist companies in developing a culture of compliance with FERC's mandatory reliability standards (the Reliability Training Tool). Additional compliance training tools are also available and being used at AmerenUE, to help ensure compliance with the standards of conduct and anti-market manipulation rules.

EEI worked with its member companies and joined NARUC, NRECA and APPA to submit comments on an EPA proposal to develop a waste heat recovery registry, urging greater accuracy in estimating economic feasibility and state rate treatment of combined heat and power.

Finally, EEI's new Institute for Energy Efficiency is playing a key role in promoting the benefits of energy efficiency to all stakeholders and providing a national perspective on state regulatory frameworks supporting utility energy efficiency programs, such as the report I have included in my testimony.

Q. Has AmerenUE already excluded from its revenue requirement that portion of EEI dues attributable to lobbying activity?

A. Yes, we have. EEI's billing to AmerenUE is segregated such that lobbying costs are specifically identified. This amount was excluded from the Company's cost of service studies prepared for this case.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	) Case No. ER-2010-0036) Tracking No. YE-2010-0054) Tracking No. YE-2010-0055

AFFIDAVIT OF STEPHEN M. KIDWELL

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Stephen M. Kidwell, being first duly sworn on his oath, states:

1. My name is Stephen M. Kidwell. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a AmerenUE as Vice President of Regulatory & Lag Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 42 pages and Schedules SMK-ER 2 through SMK-ER 6, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Stephen M. Kidwell

Subscribed and sworn to before me this 11th day of February, 2010.

Notary Public

My commission expires:

Debby Anzalone - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #06435722
My Commission Expires 5/4/2010

AmerenUE Demand Side Management (DSM) Market Potential Study Volume 1: Executive Summary

Global Report Number 1287-1

January 2010

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EXECUTIVE SUMMARY

AmerenUE engaged a team led by Global Energy Partners, LLC (Global) to perform a Demand Side Management (DSM) Market Potential Study to assess the various categories of electrical energy efficiency and demand response potential in the residential, commercial, and industrial sectors for the AmerenUE service area from 2009 to 2030. The study used updated forecasts of baseline energy use estimates based on the latest information on federal, state, and local codes and standards for improving energy efficiency.

AmerenUE will use the results of this study in its integrated resource planning process to analyze various levels of energy savings and peak demand reductions attributable to both energy efficiency and demand response initiatives at various levels of implementation cost.

This executive summary presents high-level results from this study as well as a preview of selected results from the four-volume report.

Background

The Missouri Rules of the Department of Economic Development (4 CSR 240-22) require that electric utilities in Missouri prepare an Integrated Resource Plan (IRP) that "[c]onsider[s] and analyze[s] demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process." (4 CSR 240-22.010(2)(A)) Section 4 CSR 240-22.050 prescribes the elements of the demand-side analysis, including reporting requirements. A copy of the Missouri rules governing electric utility resource planning is available on the Missouri Secretary of State's website[1].

In 2009, AmerenUE launched a portfolio of such DSM programs on a substantially larger scale than any related efforts the company has initiated in the past. These programs were analyzed and developed in 2008 drawing upon best available secondary data sources. This DSM Market Potential Study updates the previous analysis using primary market data and more detailed and comprehensive analyses.

The key objectives for this study were to:

- Assess and understand technical, economic, achievable and naturally occurring potential for all customer segments in the AmerenUE service area from 2009 to 2030.
- Analyze savings at various levels of cost.
- Conduct primary market research to collect electricity end-use data, customer demographics and psychographics.
- Understand how customers in the AmerenUE service territory make decisions related to their electricity use and energy efficiency investment decisions.
- Develop several scenarios for assessing DSM potential.
- Clearly communicate the DSM Potential in an objective way that is useful for AmerenUE senior management, AmerenUE stakeholders and AmerenUE DSM and IRP staff.

[1] Rules of Department of Economic Development Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning (4 CSR 240-22.010) – http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf

OVERALL CONCLUSIONS

This study has enlightened AmerenUE about its customer base and the potential for energy savings and peak demand reductions that are possible through energy-efficiency (EE) and demand response (DR) programs. The key highlights are as follow:

- There is more opportunity for program savings than was estimated using secondary data. Achievable potential is higher than what was concluded in the AmerenUE 2008 IRP.
- Concurrent with higher opportunities, budgets to harvest those opportunities reach an annual spend range of $100 million to $200 million by 2015. This range corresponds to 4% and 8% of AmerenUE revenues, a spending level which exceeds nearly all electric utilities in the nation.
- A comprehensive view of measures yielded higher economic potential. The study considered hundreds of measures and there are considerable savings to be had.
- AmerenUE customers are different. They express less interest in DSM investments and they do not all consider AmerenUE to be their "trusted energy advisor" at this time.

DEFINITIONS

Before launching into the discussion of results, a few key terms are defined:

- **Technical potential** is a theoretical construct that assumes all feasible measures are adopted by customers, regardless of cost or customer preferences.
- **Economic potential** is also a theoretical construct that assumes all ***cost-effective*** measures are adopted by customers, regardless of customer preferences.
- **Maximum achievable potential (MAP)** takes into account expected program participation, based on customer preferences resulting from ideal implementation conditions. MAP establishes a maximum target for the EE and DR savings that a utility can hope to achieve through its EE and DR programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs. It is commonly-accepted in the industry that MAP is considered the hypothetical upper-boundary of achievable savings potential simply because it presumes conditions that are ideal and not typically observed in real-world experience.
- **Realistic achievable potential (RAP)** represents what is considered to be realistic estimates of EE and DR potential based on realistic parameters associated with DR and EE program implementation (i.e., limited budgets, customer acceptance barriers, etc.). RAP is of most interest for this study since it represents the mid-point of achievable potential and corresponds to best practices that are attainable since the estimates are tied to known program experience from around the country.
- **Business as usual (BAU)** represents the existing AmerenUE DSM plan from the 2008 IRP and the associated impacts and costs projected into the future. For this analysis, impacts without alteration were included in the savings and cost-effectiveness assessments to represent a benchmark of what is anticipated under current practices.[2]
- **Baseline forecast** is a reference end-use forecast developed specifically for this study. This estimates what would happen in the absence of any DSM programs, and includes naturally occurring energy efficiency and any codes and standards that were in place as of June 30, 2009. It is the metric against which savings are measured.

[2] Note that it was necessary in this assessment to project savings and costs for the BAU for three additional years (2028-2030) since the IRP assessment only went as far as 2027. Savings for those three years were extended without additional growth. Costs for those three years were extended reflecting growth only due to inflation.

KEY FINDINGS

The key findings from this study encompass the potential savings from EE and DR programs, supply curves for EE and DR programs, and scenario analyses for EE and DR programs. Each set of results is summarized below. Details are presented in Volumes 3 and 4.

Energy Efficiency Potential

Realistic achievable potential in 2030 is 3,165 GWh, which represents 7.3% of total forecasted baseline usage for that year. This represents 25% of technical potential and 44% of economic potential.

- MAP in 2030 is 4,758 GWh, about 11% of the total forecasted sales in 2030. This represents more than a third of technical potential and nearly two-thirds of economic potential.
- BAU in 2030 is 2,740 GWh, 6.3% of total forecasted usage in 2030.

Table 1 and Figure 1 present estimates for all five types of potential for selected years.

Figure 2 presents forecasts of electricity use for each of the five types of potential, as well as the baseline forecast and recent historical sales. By 2030:

- Electricity use in the baseline forecast has increased by 4,432 GWh, an increase of 11.2%.
- RAP offsets growth in the baseline forecast by almost three-fourths.
- MAP more than offsets growth in the baseline forecast.
- Economic potential brings usage down to the level it was in 2005.

Table 1 Summary of Energy Efficiency Potential

	2009	2015	2020	2025	2030
Baseline Electricity Forecast (GWh)	38,839	39,057	40,248	41,899	43,181
Energy Savings (GWh)					
Technical Potential	3,434	9,115	11,098	12,296	12,696
Economic Potential	1,895	4,392	5,475	6,657	7,181
Maximum Achievable Potential	13	1,950	3,943	4,655	4,758
Realistic Achievable Potential	12	1,316	2,627	3,098	3,165
Business as Usual	264	1,399	2,184	2,596	2,740
Energy Savings as % of Baseline					
Technical Potential	8.8%	23.3%	27.6%	29.3%	29.4%
Economic Potential	4.9%	11.2%	13.6%	15.9%	16.6%
Maximum Achievable Potential	0.0%	5.0%	9.8%	11.1%	11.0%
Realistic Achievable Potential	0.0%	3.4%	6.5%	7.4%	7.3%
Business as Usual	0.7%	3.6%	5.4%	6.2%	6.3%

Figure 1 Summary of Energy Efficiency Potential (Savings as % of Baseline)

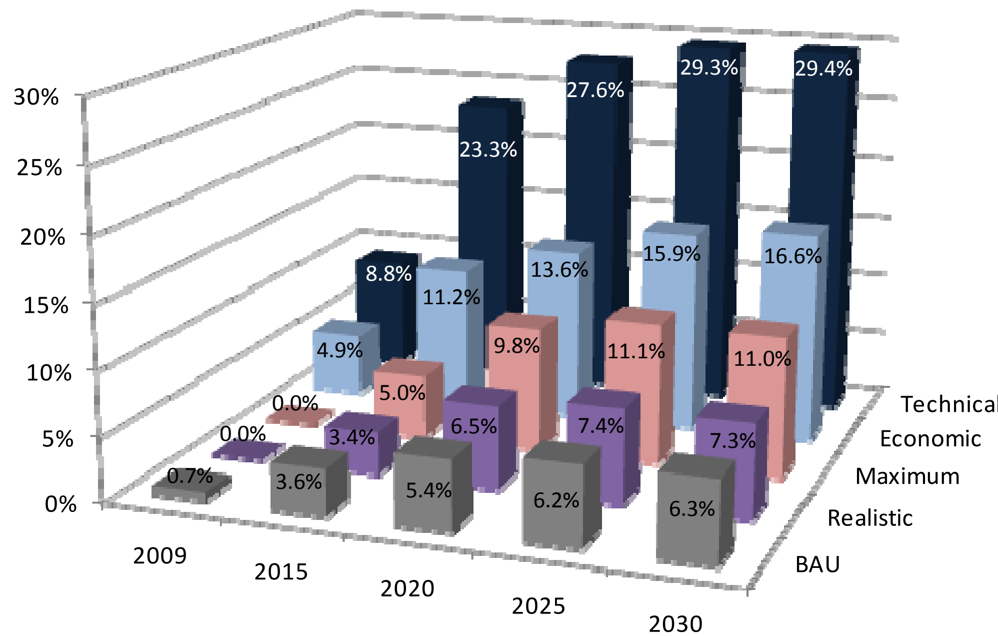
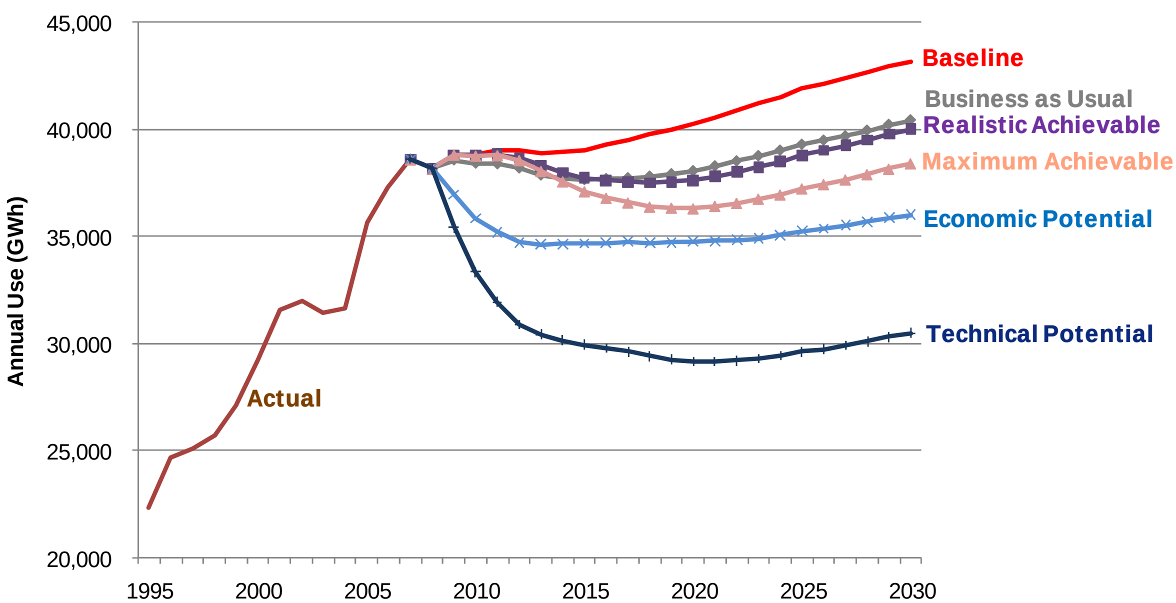


Figure 2 Forecast Summary of Energy Efficiency Potential



In addition to energy savings (GWh), energy efficiency programs also create savings in coincident peak demand (MW). Table 3 presents peak demand savings from EE programs for all five types of potential. The savings are substantial because many of the EE savings result from measures related to air conditioning across all sectors, C&I lighting and motors, all of which have high usage during peak periods. These EE peak demand savings are combined with DR peak demand savings in the following discussion.

Table 2 Summary of Peak Demand Savings from Energy Efficiency Programs

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	**7,642**	**8,003**	**8,356**	**8,752**	**9,127**
Peak Demand Savings (MW)					
Technical Potential	837	2,342	2,932	3,377	3,511
Economic Potential	454	1,166	1,444	1,715	1,846
Maximum Achievable Potential	4	563	1,072	1,269	1,253
Realistic Achievable Potential	4	381	716	846	834
Business as Usual	34	173	271	331	352
Peak Demand Savings as % of Baseline					
Technical Potential	11.0%	29.3%	35.1%	38.6%	38.5%
Economic Potential	5.9%	14.6%	17.3%	19.6%	20.2%
Maximum Achievable Potential	0.1%	7.0%	12.8%	14.5%	13.7%
Realistic Achievable Potential	0.0%	4.8%	8.6%	9.7%	9.1%
Business as Usual	0.4%	2.2%	3.2%	3.8%	3.9%

Demand Response Potential

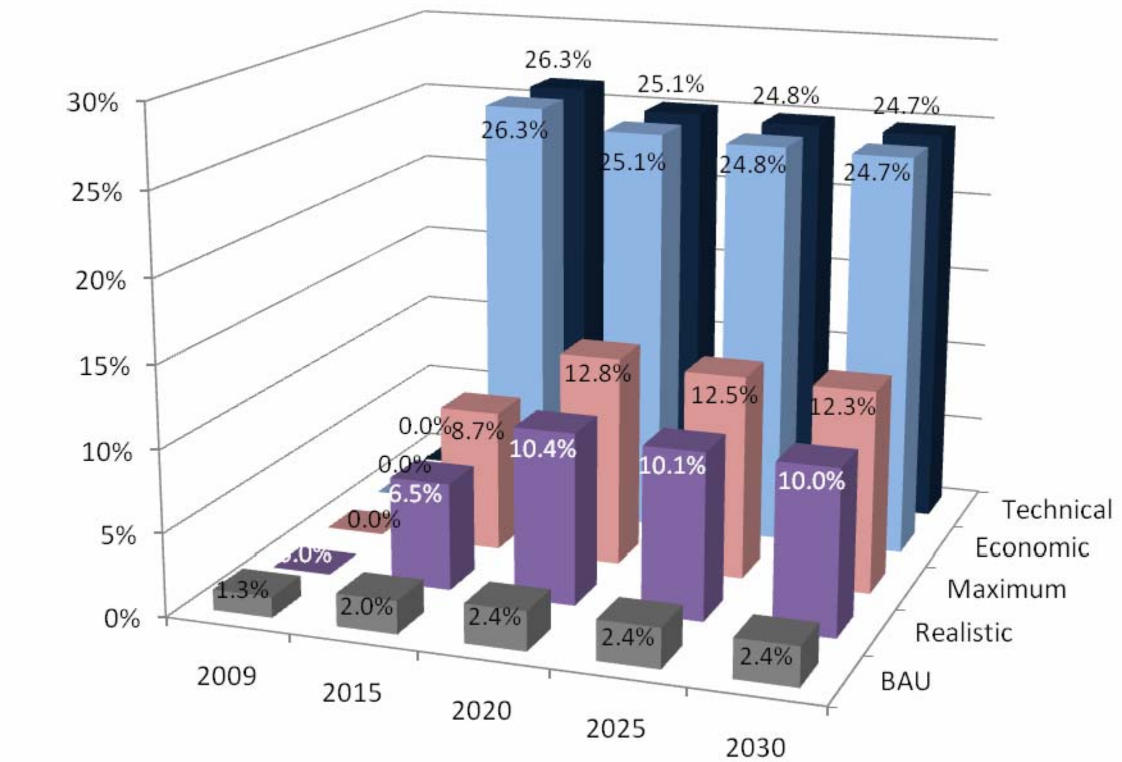
By 2030, achievable savings from demand-response programs are in the range of 914 to 1,126 MW. This represents between 10 and 12% of peak demand in 2030.

Table 3 displays the different levels of potential both as MW/year and as a percentage of baseline forecast. Figure 3 presents the savings as a percentage of coincident peak demand in selected years.

Table 3 Summary of Demand Response Potential

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	**7,642**	**8,003**	**8,356**	**8,752**	**9,127**
Peak Demand Savings (MW)					
Technical Potential	2	2,102	2,098	2,173	2,254
Economic Potential	2	2,102	2,098	2,173	2,254
Maximum Achievable Potential	2	694	1,072	1,090	1,126
Realistic Achievable Potential	2	520	870	885	914
Business as Usual	97	160	199	213	219
Peak Savings as % of Baseline					
Technical Potential	0.0%	26.3%	25.1%	24.8%	24.7%
Economic Potential	0.0%	26.3%	25.1%	24.8%	24.7%
Maximum Achievable Potential	0.0%	8.7%	12.8%	12.5%	12.3%
Realistic Achievable Potential	0.0%	6.5%	10.4%	10.1%	10.0%
Business as Usual	1.3%	2.0%	2.4%	2.4%	2.4%

Figure 3 ***Summary of Demand Response Potential (Savings as % of Baseline)***



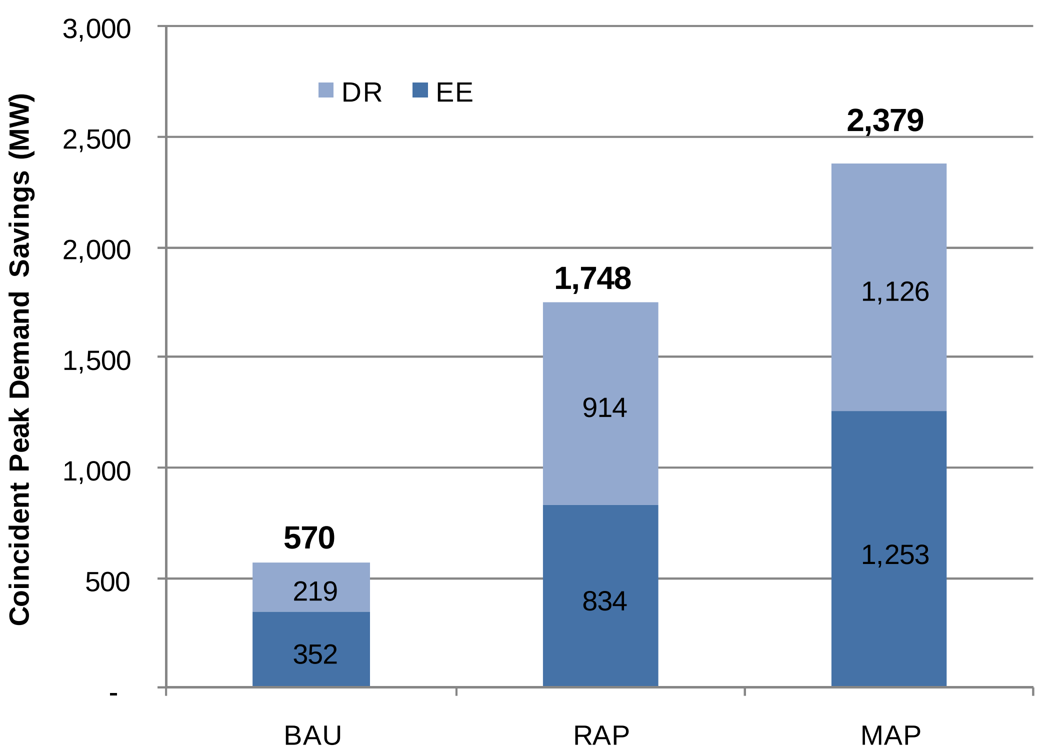
Combined Peak Demand Savings

In addition to peak-demand savings from demand response programs, the energy efficiency programs also yield savings. Throughout the forecast period, peak demand savings from EE programs for RAP and MAP are about the same as the savings from DR programs. However, in contrast to DR programs, the peak-demand savings from EE programs are permanent and non-dispatchable. Together, these savings are substantial and could potentially eliminate the need for new capacity over the next 20 years. Table 4 and Figure 4 present these results.

Table 4 Summary of Peak Demand Savings from EE and DR

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	**7,642**	**8,003**	**8,356**	**8,752**	**9,127**
EE Peak Demand Savings (MW)					
Maximum Achievable Potential	4	563	1,072	1,269	1,253
Realistic Achievable Potential	4	381	716	846	834
Business as Usual	34	173	271	331	352
DR Peak Demand Savings (MW)					
Maximum Achievable Potential	2	694	1,072	1,090	1,126
Realistic Achievable Potential	2	520	870	885	914
Business as Usual	97	160	199	213	219
Total Peak Demand Savings (MW)					
Maximum Achievable Potential	5	1,257	2,144	2,359	2,379
Realistic Achievable Potential	5	901	1,586	1,731	1,748
Business as Usual	131	333	470	544	570
Peak Savings as % of Baseline					
Maximum Achievable Potential	0.1%	15.7%	25.7%	27.0%	26.1%
Realistic Achievable Potential	0.1%	11.3%	19.0%	19.8%	19.2%
Business as Usual	1.7%	4.2%	5.6%	6.2%	6.2%

Figure 4 Combined Peak Demand Savings from DR and EE Programs in 2030



Cost-Effectiveness Analysis

The EE and DR programs were assessed for cost-effectiveness drawing upon the California Standard Practice protocol for DSM economic assessment. For the purposes of this study, four economic test perspectives from the protocol were applied. Each is briefly defined below:

- **The Total Resource Cost (TRC**) test measures benefits and costs from the perspective of the utility and society as a whole.
- **The Utility Cost (UC)** test measures the costs and benefits from the perspective of the utility administering the program.
- **The Ratepayer Impact Measure (RIM**) test measures the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the EE and DR programs.
- The **Participant (Part)** test measures the benefits and costs from the perspective of program participants as a whole.

The cost-effectiveness analysis was performed at an aggregate level, representing the potential effects of each individual EE and DR program in the portfolio.

A spreadsheet model was used as the primary tool for conducting AmerenUE's cost-effectiveness assessment.[3] Table 5 presents the results of the cost-effectiveness analysis.

Table 5 TRC Cost-Effectiveness Results

Program	Total Resource Cost (TRC)			
	Lifetime Benefits (Million$)	Lifetime Costs (Million $)	Net Benefits (Million $)	B/C Ratio
Energy Efficiency Programs				
Maximum Achievable Potential (MAP)	$4,599	$2,921	$1,678	1.57
Realistic Achievable Potential (RAP)	$3,072	$1,856	$1,217	1.66
Business as Usual (BAU)				1.95
Demand Response Programs				
Maximum Achievable Potential (MAP)	$1,124	$514	$610	2.19
Realistic Achievable Potential (RAP)	$898	$406	$492	2.21
Business as Usual (BAU)				1.68

Important insights can also be drawn by looking at the levelized cost of achieving the projected savings. Table 6 presents the estimated levelized costs for the various EE and DR program portfolios.

3 Global uses its own in-house cost-effectiveness assessment tool.

Table 6 Levelized Cost (Utility Cost perspective)

Type of Potential	Levelized Cost	
	Energy Efficiency Programs ($/kWh)	Demand Response Programs ($/kW-yr)
Maximum Achievable Potential (MAP)	$0.024	$37.45
Realistic Achievable Potential (RAP)	$0.017	$39.69
Business as Usual (BAU)	$0.021	$27.50

As the table indicates, by all measures the EE program portfolio is cost-effective from a levelized cost perspective. Industry average levelized cost tends to range from $0.03 to $0.05 per kWh saved. With the BAU portfolio, the levelized cost is well under that average. Looking at either the MAP or RAP, it is fair to conclude that the portfolio levelized costs are well within industry expectations. For the DR programs, the portfolio is cost-effective from a levelized cost perspective since the levelized cost of new capacity is typically well over $75/kW-year.[4] With any of the three portfolios, the levelized cost is well under half of that average.

Supply Curves

Two key results from this study are two sets of supply curves – one for energy-efficiency programs and the other for demand response programs – that represent MAP, RAP, and BAU.

Figure 5 shows the reference supply curve for energy-efficiency programs for 2030. Key observations include:

- Overall, the 20-year analysis shows a majority of the EE program savings fall under $0.04/kWh. For the BAU portfolio, a total savings of over 5% falls under a very attractive cost-effective cut-off of $0.03/kWh.
- For the RAP portfolio, close to 7% total savings falls under a $0.03/kWh levelized cost.
- The MAP portfolio becomes very costly when reaching beyond the 10% savings level, as the levelized cost to add additional savings beyond a cumulative savings of 10% reaches well over $0.05/kWh.
- Another interesting observation is that RAP holds steady at a levelized cost under $0.02/kWh, going from a cumulative savings of just over 2% to over 5%. Program costs do not appear to substantially increase under RAP until the portfolio reaches over 7% savings.
- While most of the programs are considered cost-effective, there are some higher cost programs which include: HVAC, Lighting and Appliance, and Residential New Construction. Residential New Construction costs are significantly higher than the second most expensive program.
- When comparing the three different curves (BAU, RAP and MAP), it is worth noting that there is a clustering of programs that cost roughly the same (on a levelized $/kWh basis), yet these programs bring about substantial increases in the energy savings potential. For MAP, bringing on the last two most expensive programs brings about measureable increases in savings potential. Thus the slope of the supply curve does not turn in a vertical direction, as is clearly demonstrated in the BAU and to some extent in the RAP cases. This suggests that while MAP is the most expensive portfolio, a bump-up in the expenditures even for the high cost programs yields significantly greater returns in terms of energy savings.

[4] This was the figure used as a proxy avoided capacity cost for the FERC National DR Potential study.

Figure 5 Energy Efficiency Program Supply Curve – Potential by 2030

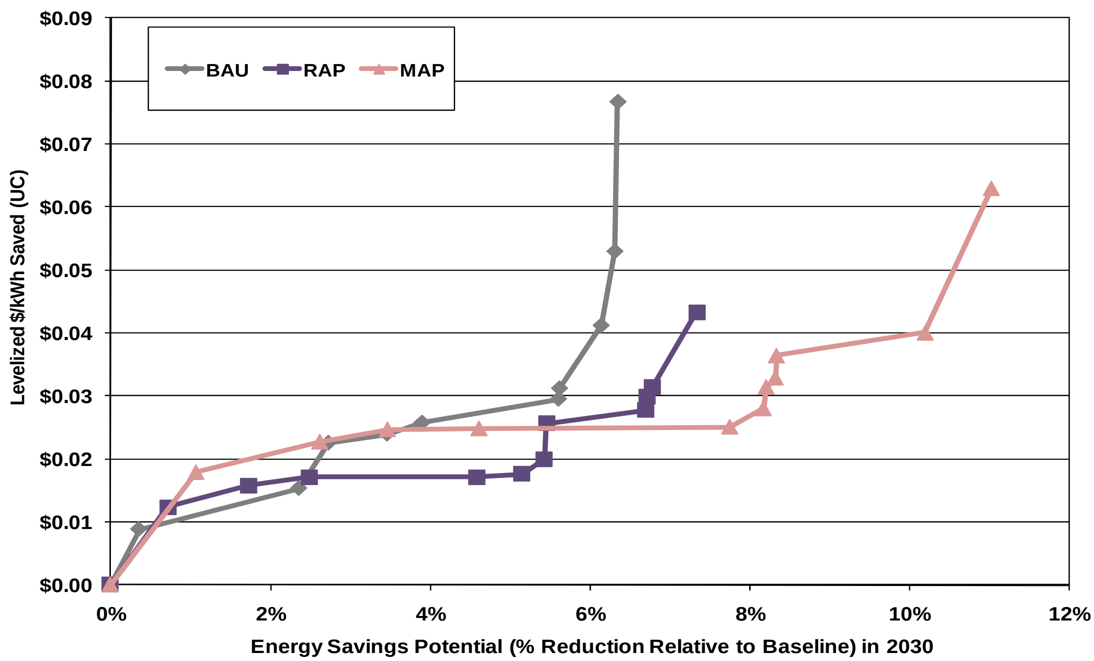
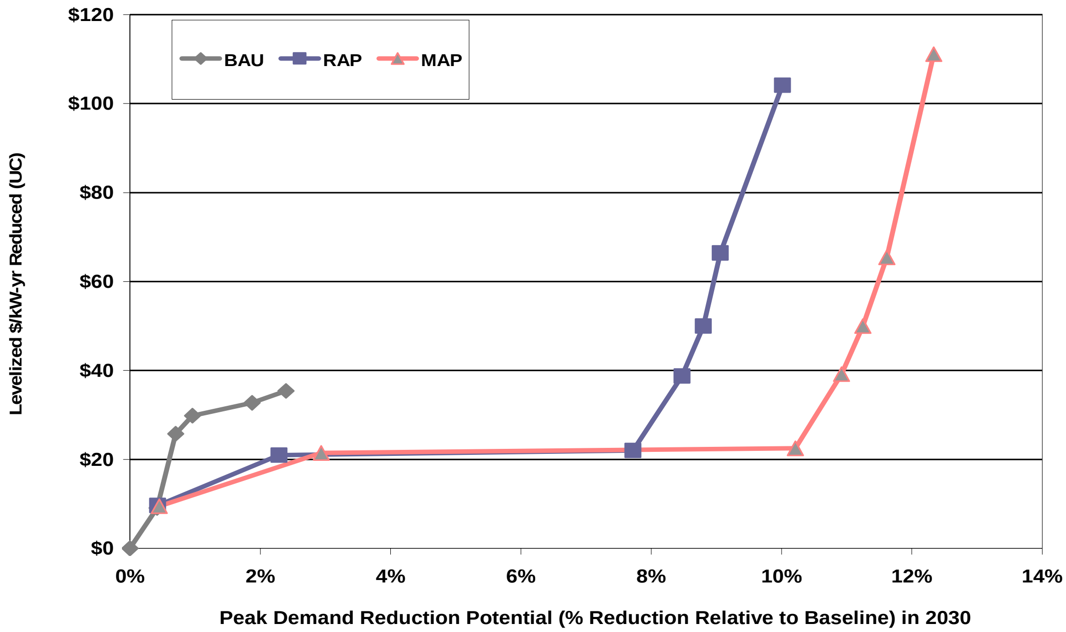


Figure 6 shows the reference supply curve for demand-response programs for 2030. Key observations include:

- In RAP and MAP, the programs as a whole appear to deliver significant peak demand reductions at a cost that is well below $30/kW-year. By any measure, this would also be judged very cost effective when compared to supply-side resources and their associated costs.
- For the BAU portfolio, savings do not go much above the 2% mark, with associated costs jumping up to above $30/kW-year.
- The RAP portfolio brings about savings at over 7% for a cost that is well under $30/kW-year.
- The MAP portfolio yields a higher savings of over 10% for essentially the same cost that is experienced in the RAP case. The reason these costs are comparable relates to the fact that the main differences between RAP and MAP relate to scale-up of DR programs under scenarios of higher incentives and assumptions about greater levels of opt-out pricing in the MAP case, which bring about significantly greater savings for very little extra cost.
- Again, most of the DR programs in each portfolio have a lower levelized cost than the projected avoided capacity costs used in the FERC National Assessment of Demand Response of approximately $75/kW-year in year 2030 indicating that all three portfolios are cost-effective as a whole.

Figure 6 Demand Response Program Supply Curve – Potential by 2030



Program Costs

An important result from this study is an estimation of program spending, both from an annual perspective and cumulative. Figure 7 illustrates the year-by-year EE program spending over the entire 22-year time horizon (2009-2030). The figure illustrates that for BAU and RAP, the annual spend is roughly equivalent (yet the RAP savings are significantly higher than BAU in each year after about 2013). The figure also illustrates the fact that the MAP spend is significantly higher than RAP and BAU. Of course, MAP savings are substantially higher than BAU and RAP. The results lead to the obvious conclusion that it will cost significantly more to get additional savings.

Figure 7 Annual Energy Efficiency Program Spending[5]

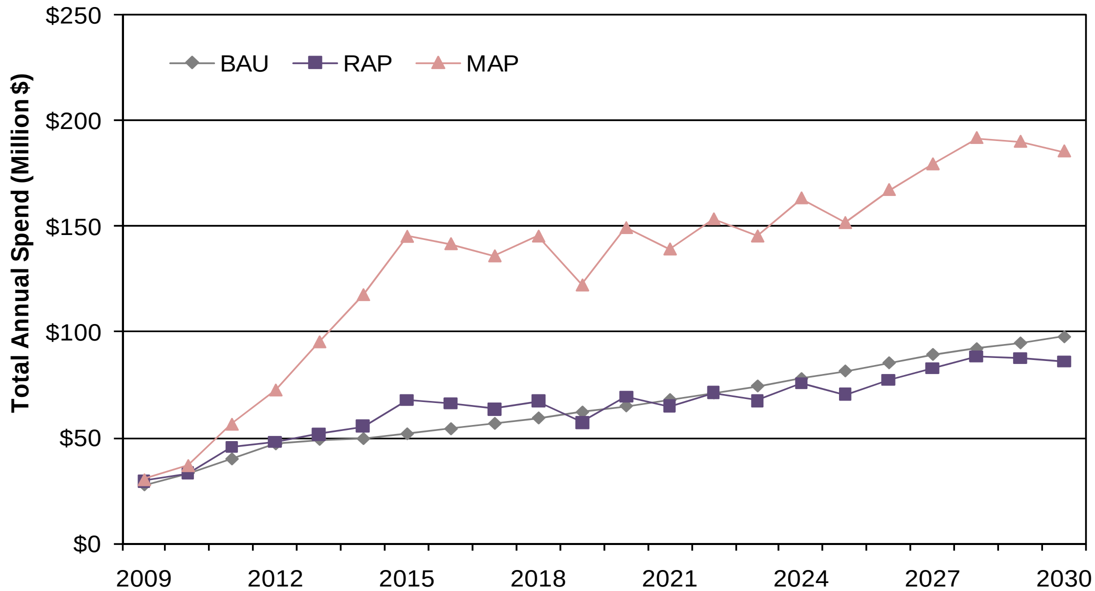


Figure 8 illustrates the year-by-year DR program spending over the entire 22-year time horizon (2009-2030). The figure illustrates significant fluctuations in the annual spending for all three cases. In the RAP case, it is assumed that AMI comes in around 2015 and that opt-in dynamic pricing is implemented afterwards. Since opt-in pricing assumes that participants are voluntary, the rates of growth in spending are what would typically be expected in a DR program.

However, for the MAP case, the spending grows dramatically in the first 5 years (2009-2013), reflecting a significant ramp-up of participation in traditional DR programs such as Direct Load Control and Curtailable as well as newer DR programs such as opt-in dynamic pricing tariffs. Beginning in 2014 the spending drops down for the one year, and then again rises dramatically until about 2020. This is occurring because it is assumed that customers are participating in the dynamic pricing programs on an opt-in or voluntary basis through 2013. In 2014, there is a transition in the pricing program designs from the opt-in style to a more mandatory opt-out style. That means that all customers not currently on a time-based pricing tariff would be defaulted to such a tariff. This transition occurs based on the assumption that the AMI meters begin to become deployed starting in 2015. As AMI deployment is initiated, pricing program expenditures rise to bring on the new participants until 2020 when it is assumed that all available participants are transitioned to the various dynamic pricing programs. While it is merely speculation as to whether opt-out dynamic pricing tariffs would actually be implemented in the AmerenUE service territory during this time, the differences in annual spend between MAP and RAP reveal some important insights about the tradeoffs between opt-out dynamic pricing vs. opt-in dynamic pricing. First, it is clear that there would be significant fluctuations in spending in the dynamic pricing case. Such fluctuations may not be feasible from an AmerenUE operational perspective. Second, as mandatory dynamic pricing tariffs take hold, there is a negative impact on program participation for other non-pricing programs. This situation is clearly revealed in the annual spend, where RAP spending in the last 10 years of the plan is actually higher than MAP spending.

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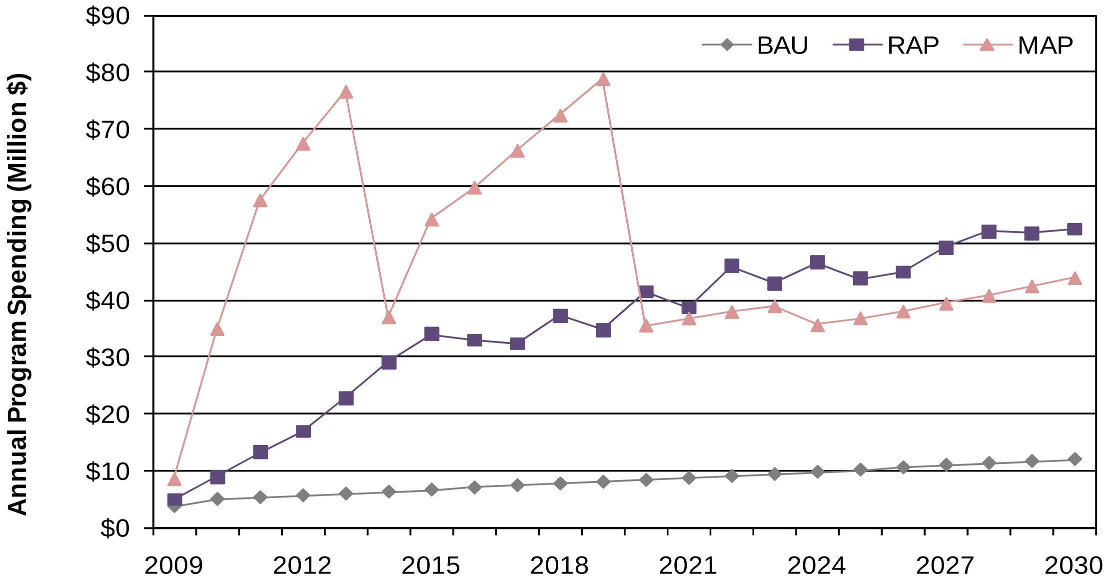
[5] Note that annual spending for MAP and RAP was calibrated to the BAU for the purposes of creating this illustration. The calibration was done such that spending amounts in the first two years of the programs would be roughly comparable across the three levels (MAP, RAP and BAU). The actual analyses of MAP and RAP (in terms of savings and cost-effectiveness) were conducted independently of BAU.

Figure 8 Annual Demand Response Program Spending



Scenario Analysis

Scenario development is a critical part of any planning exercise. While the “reference” case for EE and DR program potential represents the best or most-likely estimate of what the future will look like, it is important to understand the sensitivity of the reference case estimate to key assumptions and to evaluate alternative worlds or scenarios. Based on the results of the potential analysis, it was determined that the realistic achievable potential (RAP) would serve as the representative reference case for conducting the scenarios analysis.

During the various stakeholder meetings convened over the course of this project, several potential future scenarios were outlined and reviewed. In those discussions, it was clear that a whole host of external factors might occur in the future, all potentially influencing the outcome of AmerenUE’s EE and DR programs. As a result, the following three scenarios were considered for the analysis:

- **Scenario 1 – Aggressive Codes and Standards**: This scenario represents the implementation of aggressive state building codes which will capture lost opportunities in new construction that might currently be captured (at least in part) in the various DSM new construction programs. Further, the scenario represents aggressive appliance standards that are currently being contemplated at the federal level. As recent increased national attention is being given to role of energy efficiency in the economic recovery and the Smart Grid, it is conceivable that this attention will lead policymakers to increase laws and regulations governing codes and standards beyond existing and planned levels.
- **Scenario 2 – High Infrastructure Costs**: This scenario anticipates greater levels of utility spending due to higher than anticipated costs associated with new generation, compliance with environmental regulations and carbon legislation[6], widespread implementation of the Smart Grid, adoption of distributed generation and solar, and the like.
- **Scenario 3 – Prolonged Recession Beyond 2 Years**: This scenario assumes that the economy does not recover in the next two years, but rather that the recession lasts up to

[6] The Reference scenario assumes passage of legislation similar to the 2009 proposed Waxman-Markey Bill. A carbon cost is included in the forecasts beginning in 2014 that reflects the targets and assumptions therein. These carbon costs are thus included in each scenario unless modified as noted.

five years. As a result, there would be a delayed and weakened carbon legislation passed by the Congress and rate hikes would be kept to a minimum.

Table 7 highlights the key findings of the scenario analysis. The table provides key indicators of the EE and DR programs, including total cumulative expenditure over the entire study time horizon (2009-2030), the levelized cost of saved energy and peak demand, and the percentage reduction relative to the baseline forecast.

Table 7 Scenario Impacts on EE and DR Potential

Parameter	Reference Case (RAP)	Scenario 1: Aggressive Codes and Standards		Scenario 2: High Infrastructure Costs		Scenario 3: Prolonged Recession	
		Value	Percent Change	Value	Percent Change	Value	Percent Change
EE Program Total Expenditure (Million $)	$1,856	$1,555	-16%	$2,394	29%	$1,522	-18%
EE Portfolio Levelized Cost ($/kWh-saved)	$0.017	$0.018	8%	$0.021	23%	$0.018	4%
EE Portfolio % Reduction Relative to Baseline	7.33%	5.18%	-29%	9.12%	24%	5.88%	-20%
DR Program Total Expenditure (Million $)	$406	$370	-9%	$657	62%	$406	0%
DR Portfolio Levelized Cost ($/kW-yr saved)	$39.69	$39.923	1%	$38.87	-2%	$38.88	-2%
DR Portfolio % Reduction Relative to Baseline	10.01%	9.32%	-7%	15.21%	52%	9.94%	-1%

Several observations can be made from the results of the scenario analysis:

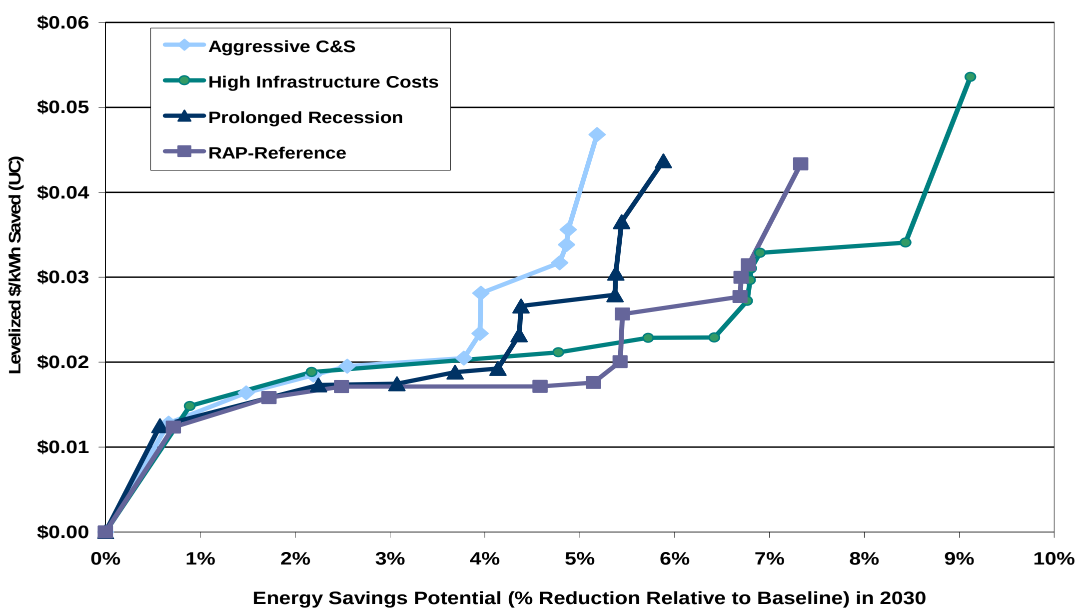
- As we move from the reference case (RAP) to the various scenarios, most of the typical parameters are moving in the direction that is expected. Aggressive codes and standards and a prolonged recession bring about lower expenditure for programs, lower savings relative to the baseline and higher levelized costs. High infrastructure costs bring about higher expenditure for programs, higher savings relative to the baseline and higher levelized cost.
- For Scenario 1 (Aggressive Codes and Standards), total EE expenditures are reduced by 16% and DR expenditures reduced by 9% due mainly to the fact that lower impacts mean that less is being expended for program administration and incentives. Levelized costs for the EE portfolio increase by 8% and for the DR portfolio by 1% indicating that the reduction in expenditures is not leading to a proportional reduction in impacts. Finally, the EE portfolio percentage reduction drops by 29% and the DR reduction drops by 7%, which is largely a function of the aggressive codes and standards taking over nearly a third of the savings projected in the reference case.
- For Scenario 2 (High Infrastructure Costs), total EE expenditures increase by 29% and DR expenditures increased by 62% due mainly to the fact more programmatic activities due to lower avoided costs, more aggressive marketing of programs, and the like. Levelized costs for the EE portfolio increase by 23% and for the DR portfolio drops by a slight 2% indicating that the increase in expenditures is bringing about a proportional increase in impacts (at least for the EE programs) . Finally, the EE portfolio percentage reduction increases by 24% and the DR reduction drops by 52%, This again is mainly driven by the fact that the EE and DR programs are operated at higher budget levels thus bringing about a larger number of participants relative to the Reference Case which in turn leads to greater impacts.

- For Scenario 3 (Prolonged Recession), total EE expenditures decrease by 18% and DR expenditures remaining relatively unchanged. The decrease in EE expenditures is due mainly to the fact few program participants is leading to less in incentives being paid out. DR appears to be relatively unchanged by these exogenous factors. Levelized costs for the EE portfolio increase by 4% and for the DR portfolio decrease by 2% indicating that (like Scenario 1) the reduction in EE expenditures is leading to a proportional reduction in impacts which has very little impact on the levelized cost. Finally, the EE portfolio percentage reduction decreases by 20% and the DR reduction increases drops by less than 1%. This again is mainly driven by the fact that the EE programs are not attracting as many participants because the economic situation is inhibiting the ability of participants to make capital investments. Thus, the resulting impacts are depressed relative to the Reference Case. This situation was not as affected in the DR case.

In addition to estimates of potential for each scenario, EE and DR program supply curves were also developed. The reference case (RAP) and each of the three scenarios are represented as separate supply curves on the same graph, in much the same manner as was presented for the various program implementation levels reported in the previous chapter.

Figure 9 shows the supply curve for AmerenUE's potential EE programs, as reflected by each of the three scenarios for the year 2030. The supply curve from the reference case is provided for comparison purposes.

Figure 9 EE Program Supply Curve – by Scenario, Year 2030



Several observations can be made from the results of the 20-year supply curve analysis for the various scenario assessments of the EE programs:

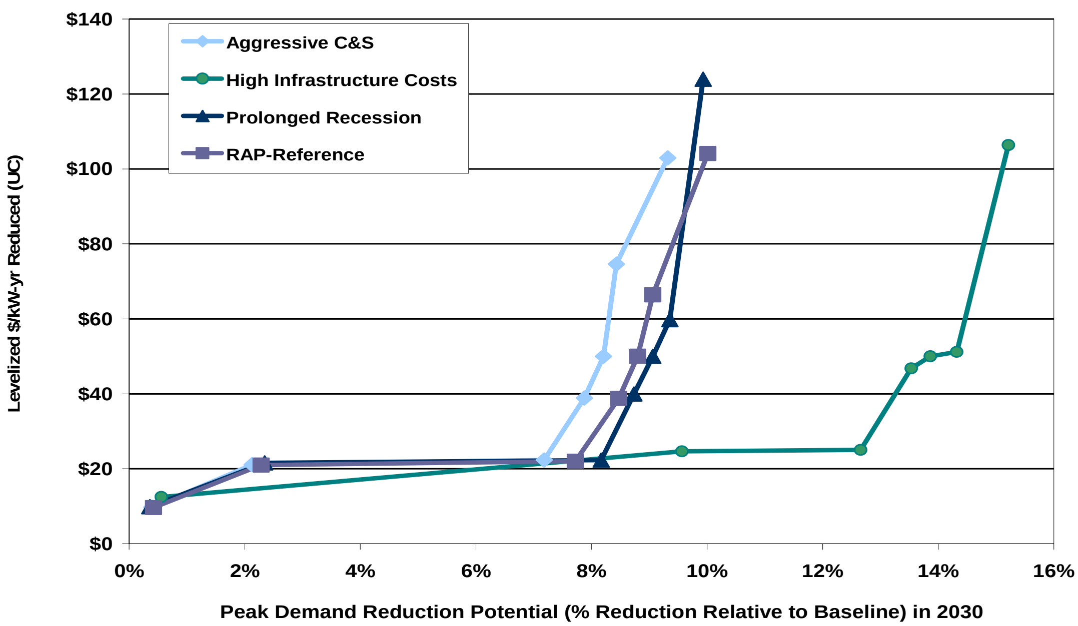
- Up to about 4% energy savings potential, all of the scenarios deliver about the same level of savings at the same level of cost (around $0.02/kWh or less). However, going above that levelized cost threshold, significant variances occur.

- Neither Scenario 1 (Aggressive C&S) nor Scenario 3 (Prolonged Recession) would be favorable from the perspective of an AmerenUE EE program portfolio. Both cases show significantly higher costs for a relatively minimal increase in savings potential.
- Scenario 2 (High Infrastructure Costs) appears to be most favorable from the perspective of bringing about 6.5% in energy savings potential at the lowest level of cost. However, for every extra kWh saved beyond that level, the costs rise dramatically.

Figure 10 shows the supply curve for AmerenUE's potential DR programs, as reflected by each of the three scenarios for the year 2030. Several observations can be made from the results of the 20-year supply curve analysis for the various scenario assessments of the DR programs:

- There is very little difference between the Reference Case and Scenario 1 (Aggressive Codes and Standards) and Scenario 3 (Prolonged Recession). This has mainly to do with the fact that in both instances these external factors have very little influence on the DR program portfolios.
- For Scenario 2 (High Infrastructure Costs) there is a pronounced improvement in the cost of delivered demand relative to the Reference Case. In other words, it does not appear to cost much more on a $/kW-year basis but the savings are significantly greater.

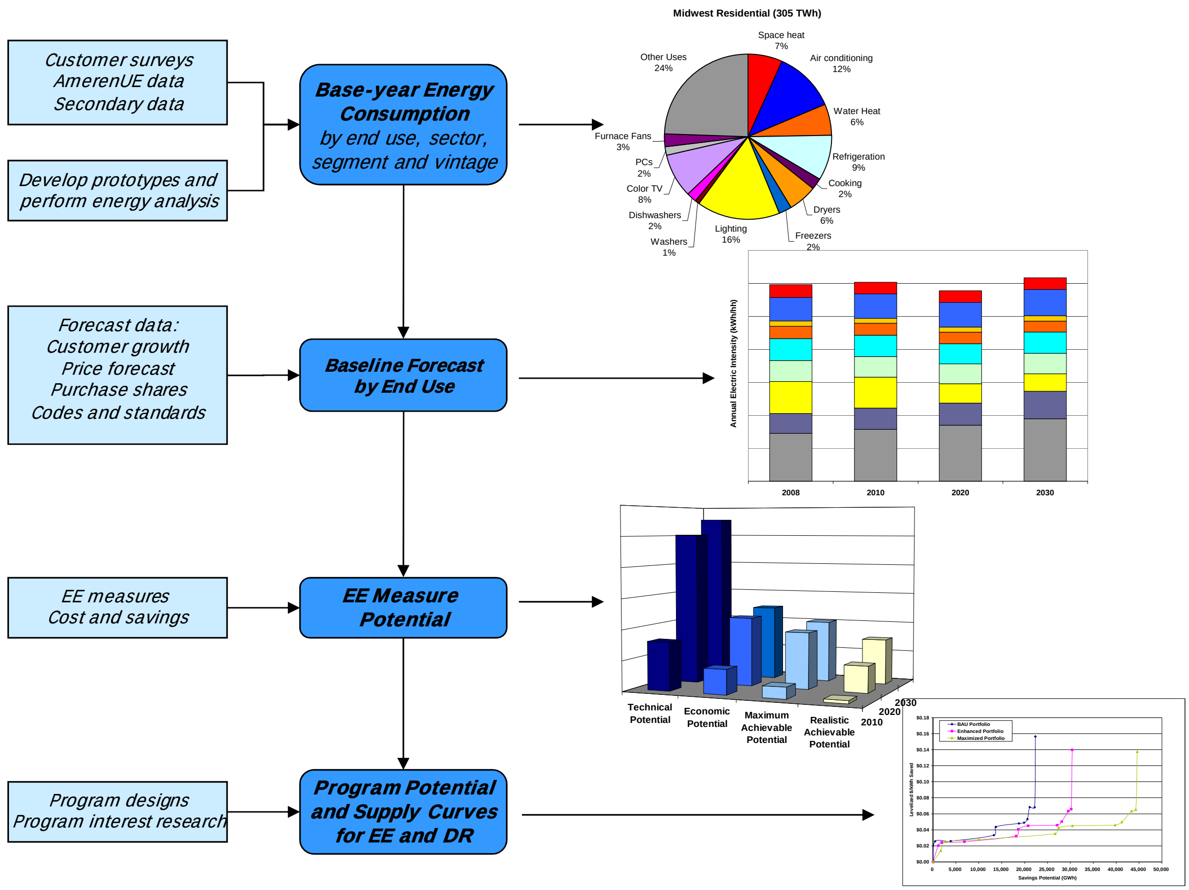
Figure 10 DR Program Supply Curve – by Scenario, Year 2030



STUDY APPROACH

This study represents industry best-practices in assessment of DSM potential. It began with comprehensive market research of AmerenUE customers that covered their current energy-using equipment, behavior and attitudes. The market research results were used to develop base-year usage profiles and the baseline forecast. These, in turn, were used to support the analysis of EE and DR potential at the measure and program levels. Finally, program analysis was used to develop supply curves. Figure 11 depicts this approach.

Figure 11 Overview of Study Approach



The remainder of this Executive Summary provides an overview of the market research and each of the analysis steps.

MARKET RESEARCH

Comprehensive market research about AmerenUE customers was conducted for this project. This research provides a solid foundation for the analyses performed in this study and it also provides a wealth of information for future analyses across many departments at AmerenUE. The market research included:

- Residential customers – online saturation surveys with 1,284 customers and online program interest surveys with 1,126 customers
- Small and medium C&I customers – online saturation surveys with 800 customers and online program interest surveys with 750 customers

- Large C&I customers – online energy-use surveys with 221 customers and online program-interest surveys with 273 customers
- Complex C&I customers – 145 site visits distributed strategically among campuses/locations of AmerenUE's "top customers"
- Trade Allies – 40 telephone interviews

Volume 2 of the report series presents the detailed results of the market research.

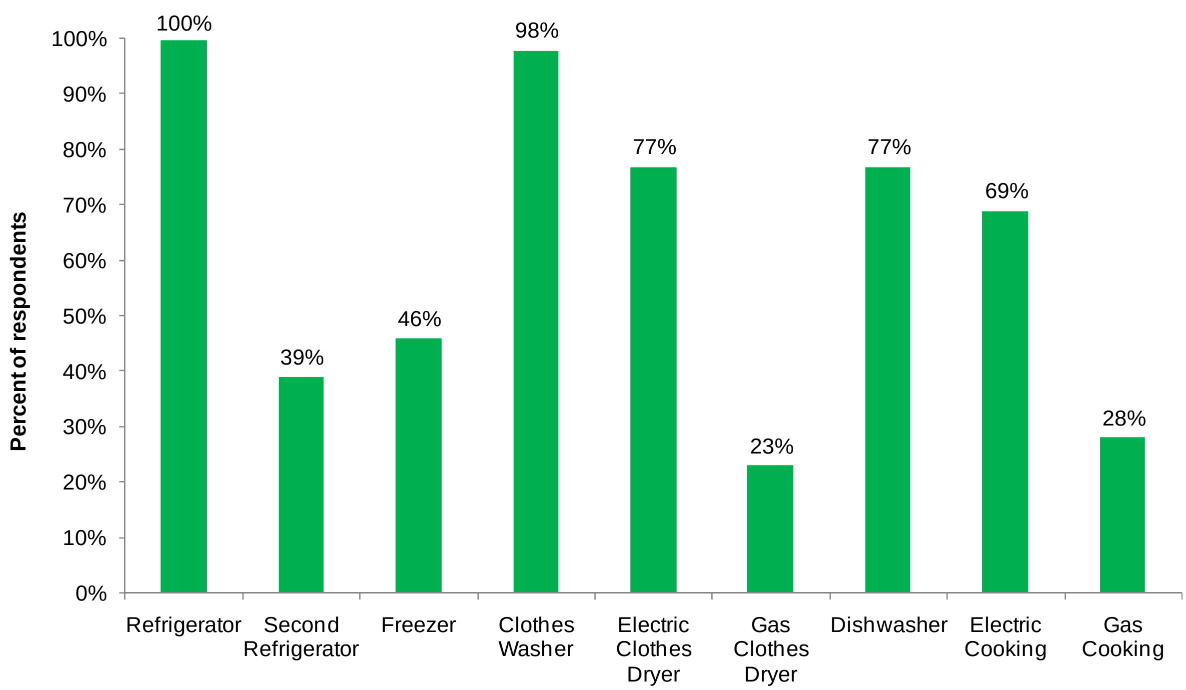
Energy-use Surveys

Energy-use (or saturation) surveys were conducted across all customer classes. Topics included:

- Characteristics of households/homes and businesses/buildings and their occupants
- Heating, cooling and water heating equipment
- Lighting, refrigeration and food service equipment
- Office equipment, electronics and miscellaneous plug loads
- Motors and process uses
- Energy-efficiency measures taken and planned

Figure 12 presents one example of the results from the residential saturation survey.

Figure 12 Saturation Survey Results – Percent of Single-family Homes with Appliances



Program-Interest Research

A hallmark of the AmerenUE study is the research of customer attitudes and behaviors toward energy efficiency and demand response measures and programs. The objectives of this research were to:

1. Help AmerenUE estimate achievable potential

a. How likely are customers within each sector to participate in various energy efficiency programs AmerenUE is considering offering?

b. Which of these energy efficiency measures offer the highest likely participation rates?

c. How does likelihood to participate differ by payback period for the customer?

2. Help AmerenUE understand unique customer segments to support customer marketing and outreach

The topics covered by the program-interest research included:

- Attitudinal questions, which included general attitudes about energy use, energy efficiency, environmental concerns, saving money, comfort, etc.; purchasing attitudes, preferences, practices; and attitudes toward electric utility providers in general and attitudes toward AmerenUE
- Assessment of energy efficiency measures already implemented
- Interest in potential energy efficiency and demand response measures offered by AmerenUE that cover appliance and equipment upgrades to high-efficiency models, improvements in processes that would save energy, and likelihood of undertaking certain energy conservation measures.

Key results from the program interest research included "take rates" for various program concepts. Take-rates represent the likelihood that customers will participate in specific programs and they reflect a snapshot of current behavior and circumstances. They have been adjusted for response bias using industry standard techniques to reflect what customers *actually* do rather than what they *say* they will do.

Figure 13 illustrates the range of take rates for the residential and business sectors. Figure 14 and Figure 15 present likely take rates for specific appliances/equipment.

Figure 13 Range of Take Rates

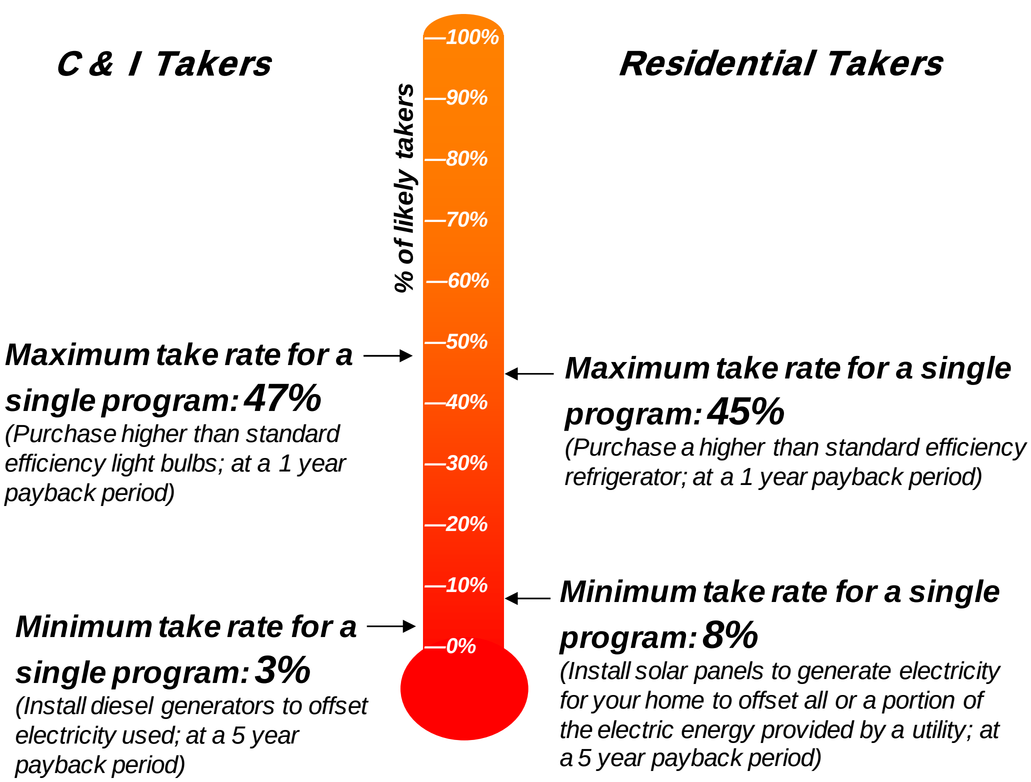


Figure 14 Likely Residential Take Rates for Purchasing High-efficiency Equipment

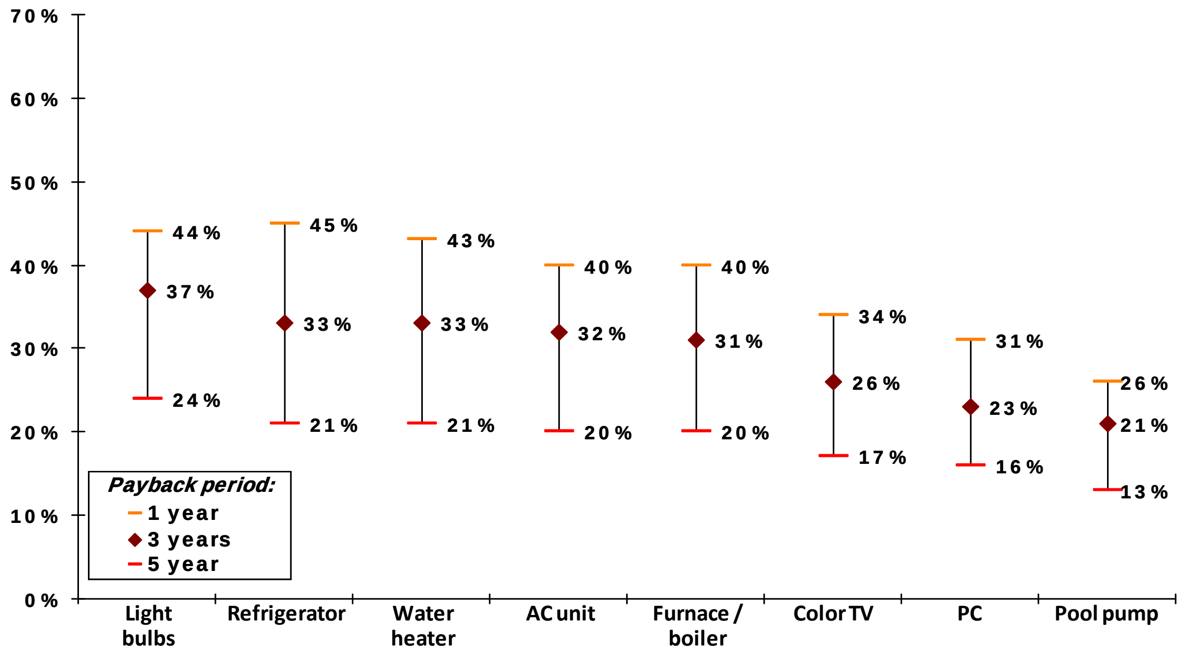
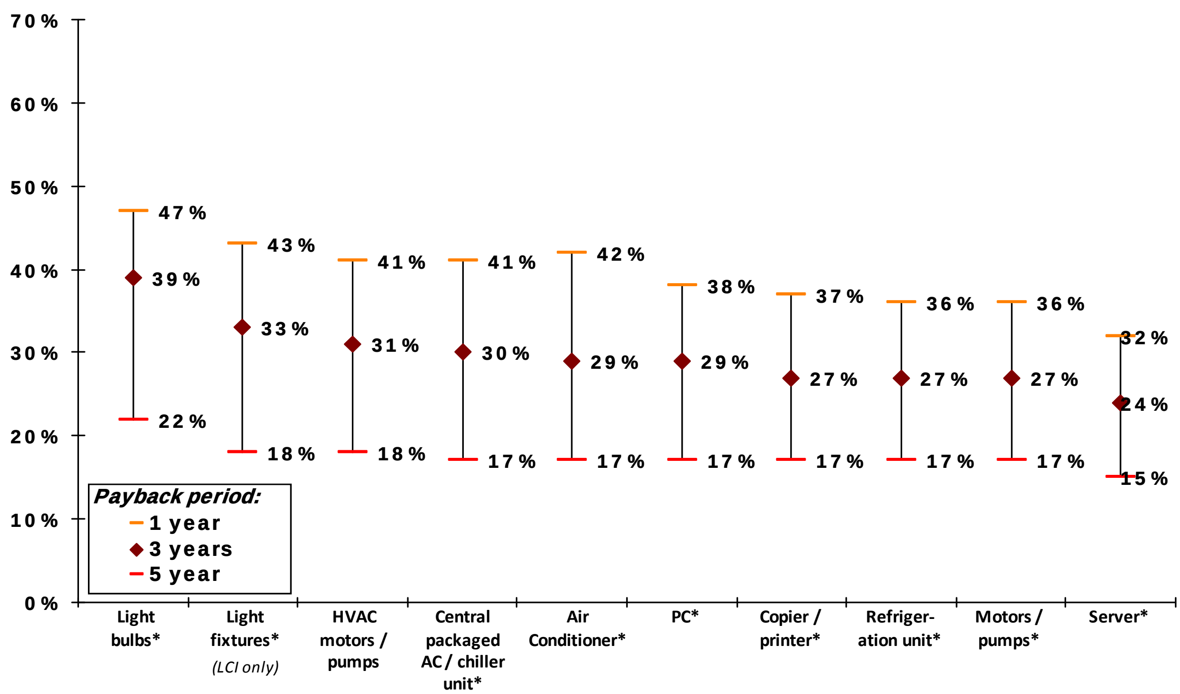


Figure 15 Likely C&I Take Rates for Purchasing High-efficiency Equipment



These take rates are used directly to estimate the various levels of achievable potential for this study – MAP and RAP. Take-rate estimates at a one-year payback were used to estimate MAP. Take-rates at a three-year payback were used to estimate RAP and were ramped up over the 20-year forecast horizon to reflect increased awareness of utility programs.

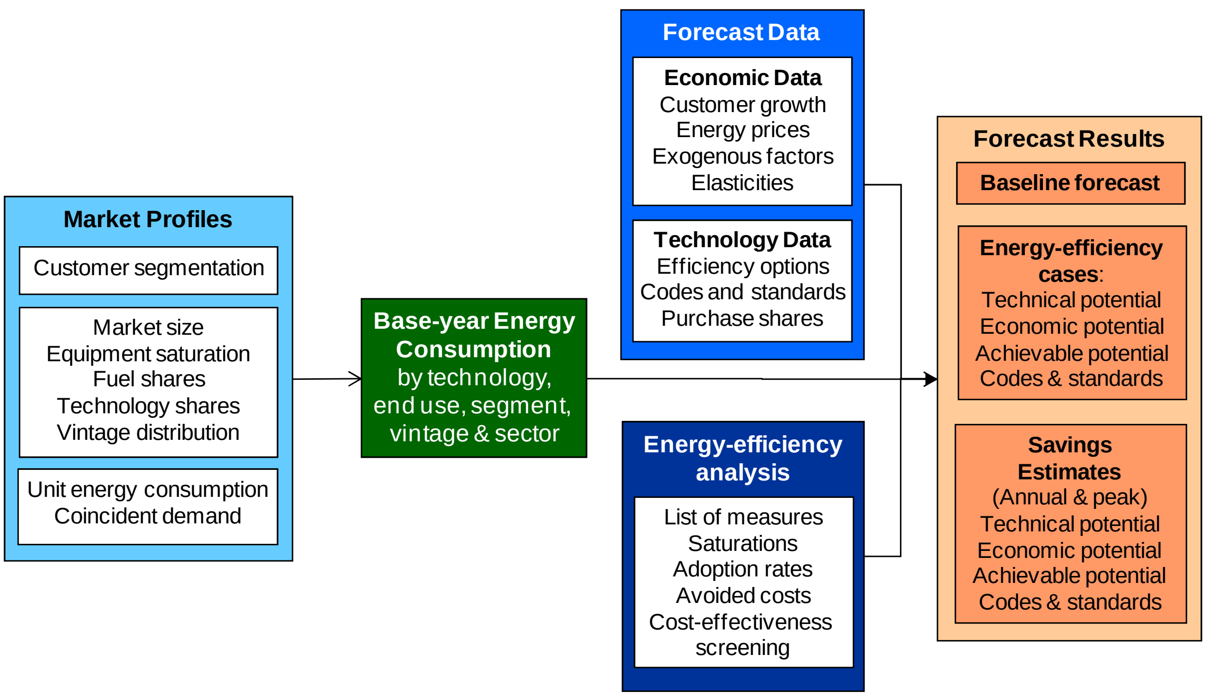
The majority of the AmerenUE take rates under a three-year payback are in the range of 20-40%. Based on observation and expert judgment, these are lower than comparable studies conducted for West Coast and Northeast utilities, which typically show 30-50%. By comparison, a recent similar study conducted by the Electric Power Research Institute identified take rates of 50% or higher, reflecting a mix of states with high and low DSM activity and history.[7] The result of lower take rates is that MAP and RAP for AmerenUE represent a smaller portion of economic potential than what is projected in some other studies.

In addition to the program take rates, the market research results were used to perform a segmentation analysis. These results are also presented in Volume 2.

DEVELOP BASELINE FORECAST

The market research was a primary source of information for the development of energy market profiles, base-year electricity use by end use and the baseline forecast as illustrated in Figure 16. For this study, 2008 was defined as the base-year because it was the most recent year for which complete billing data were available.

Figure 16 Analysis Framework for Baseline and EE Potentials Forecasts



Base-year Energy Use

In 2008, AmerenUE provided 38,165 GWh of electricity to its residential, commercial and industrial customers. The residential and commercial sectors are roughly equal, each accounting for more than one third of total use. The industrial sector accounts for the remaining 28%.

Residential Electricity Use in 2008

In 2008, AmerenUE provided electricity service to 1.04 million households who used 13,993 GWh. Overall, residential customers used 13,498 kWh/household. The market is dominated by

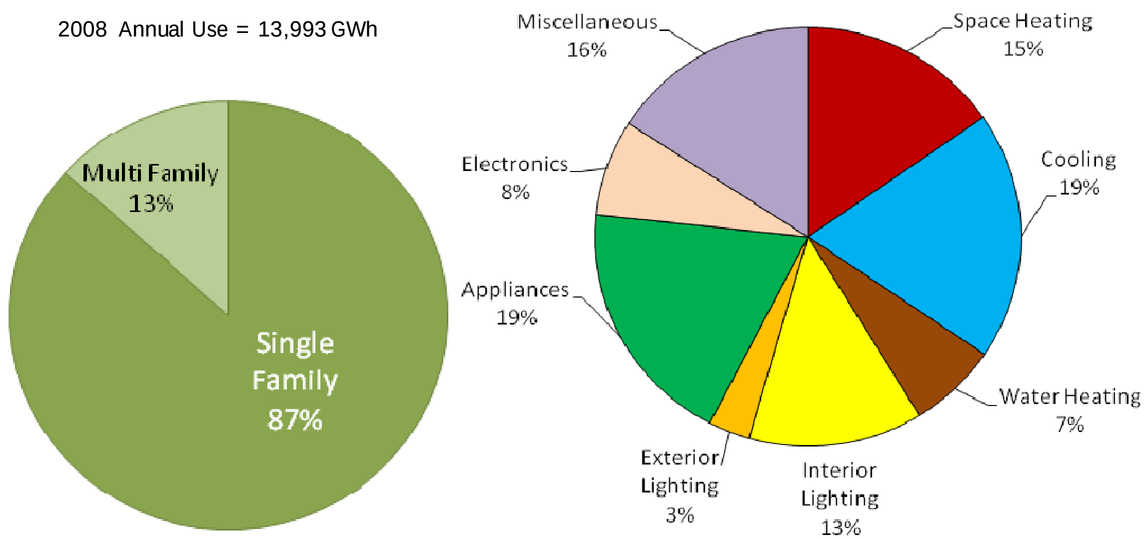
[7] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030), EPRI, TR 1016987, January 2009, available at www.epri.com.

single-family homes (see Figure 17), which used 14,682 kWh/household on average, compared to multi-family homes which used 8,883 kWh/household.

Appliance information and dwelling characteristics from the market research were combined to develop descriptions of prototypical houses in the AmerenUE service area. These prototypes were analyzed using an engineering simulation model to estimate end-use consumption.[8] Comprehensive energy market profiles that characterize electricity usage by end use and segment are presented in Volume 3.

Figure 17 presents a breakdown of 2008 usage by end use. Air conditioning and white-goods appliances are the largest uses, followed by space heating and interior lighting.

Figure 17 Residential Electricity Usage by Segment and End Use



Commercial Sector Electricity Use in 2008

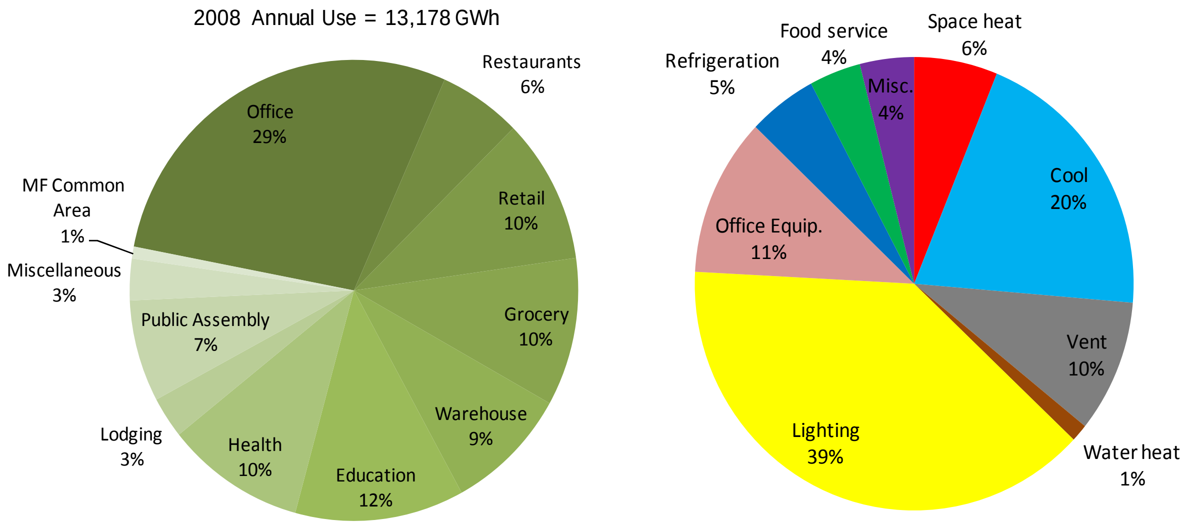
In 2008, AmerenUE provided 13,178 GWh to commercial-sector customers. These businesses occupied 964 million square feet, implying an intensity of 13.7 kWh per square foot per year. The largest segment in the commercial sector is offices, which accounts for 29% of total usage in 2008. All other segments account for 12% or less of total use (see Figure 18).

Information about equipment inventories, business operations and building characteristics from the survey were combined to develop descriptions of prototypical building types in the AmerenUE service area. These prototypes were analyzed in BEST to estimate end-use consumption. Comprehensive energy market profiles that characterize electricity usage by end use and segment are presented in Volume 3.

Figure 18 presents a breakdown of 2008 usage end use. Lighting is the dominant use in the commercial sector, followed by space cooling.

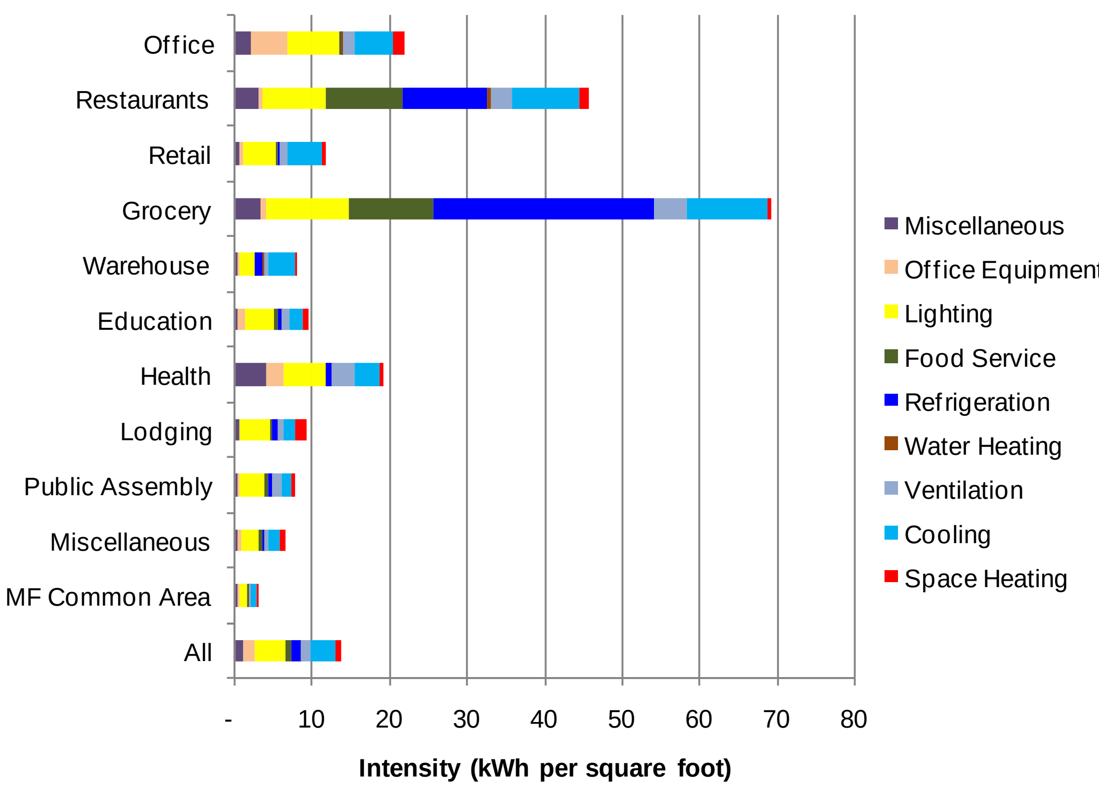
[8] The model used for this purpose is Global's Building Energy Simulation Tool (BEST), which is a user-friendly front-end to the powerful DOE-2 energy simulation model.

Figure 18 2008 Commercial Sector Electricity Usage by Segment and End Use



Electricity use varies considerably by building type and end use. Figure 19 presents the overall intensity in kWh per square foot per year, as well as the end-use breakdown. The grocery and restaurant segments are the most intensive as a result of high refrigeration and food service usage, in addition to lighting and cooling. Lighting and cooling are significant uses across all segments. Office is the largest segment, in terms of absolute kWh usage, and uses about 22 kWh per square foot on average.

Figure 19 Electricity Use by Building Type and End Use

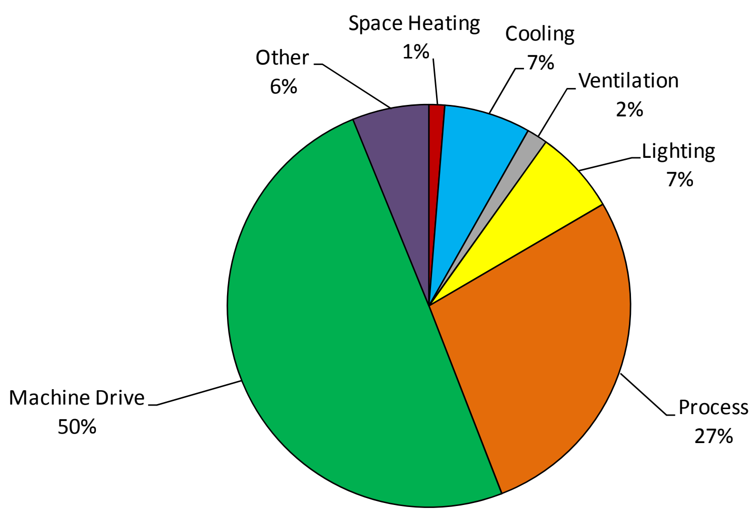


Industrial Sector Electricity Use in 2008

In 2008, AmerenUE provided 10,994 GWh to the industrial sector. Throughout this study, this sector is treated as a whole to protect the confidentiality of AmerenUE's largest customers who might otherwise be identified.

Figure 20 presents a breakdown of 2008 usage by end use for the industrial sector. Machine drives, primarily motors and air compressors, account for 50% of usage in 2008. Electric processes account for just over one fourth of usage. Lighting, cooling, and other uses account for the remaining 23%.

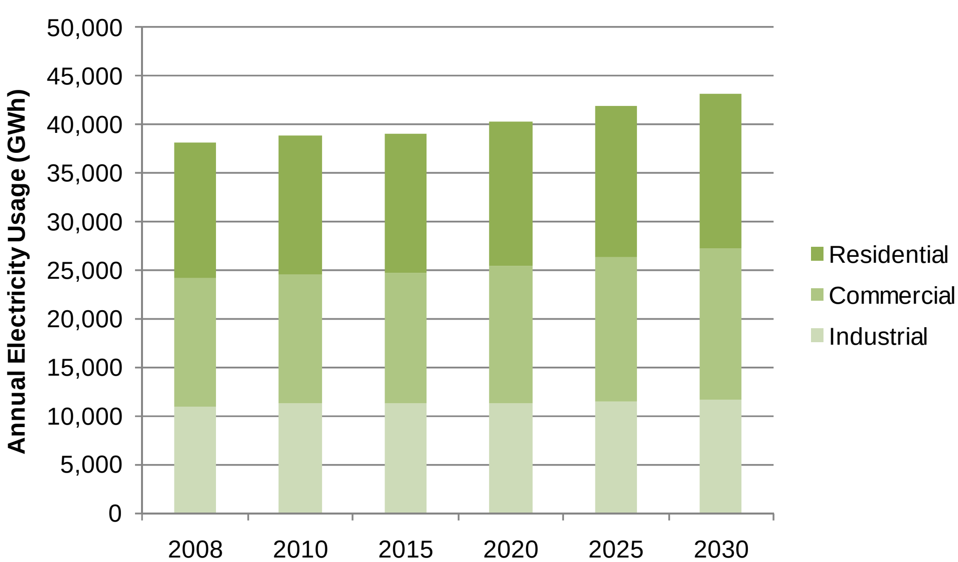
Figure 20 2008 Industrial Electricity Usage by End Use



Baseline End-Use Forecast Results

Using the base-year profiles as a starting point, a baseline end-use forecast was developed for 2009 through 2030 using Global's LoadMAP model. This forecast embodies assumptions about customer growth, electricity prices, technology trends and the impacts of codes and standards. This forecast provides the springboard for the estimation of energy-efficiency potential and is the metric against which EE savings are measured. The total forecast is presented in Figure 21.

Figure 21 Baseline Forecast Summary



Residential Baseline End-use Forecast

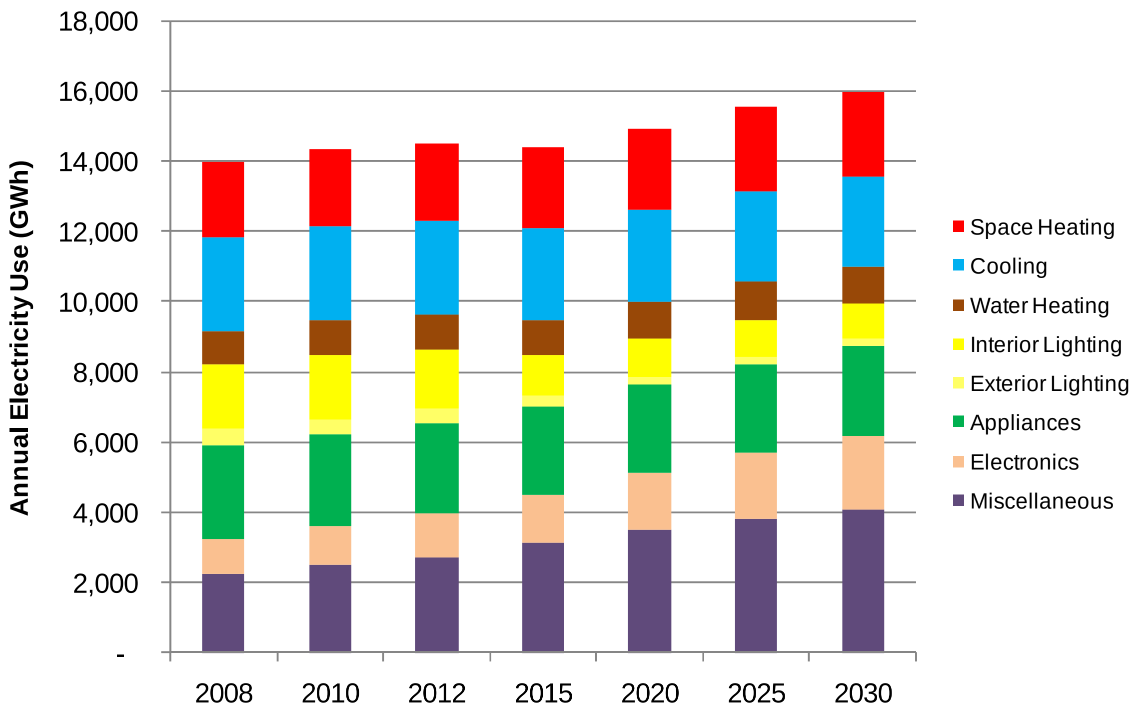
Electricity use is forecast to grow from 13,993 GWh in 2008 to 15,986 GWh in 2030. This is a 14% increase over the 22 years, implying an average growth rate of 0.61%.

Key observations about this forecast include the following:

- Residential lighting is affected by the passage of the Energy Independence and Security Act (EISA) in 2007, which mandates higher efficacies for lighting technologies starting in 2012. Several lighting technologies are anticipated to meet this standard when it goes into effect, including compact fluorescent lamps (CFL), white light-emitting diodes (LED), and advanced incandescents currently under development. Old stock is phased out over time beginning in 2012. The effect of this standard is a decline in electricity for lighting use by 43% over the forecast period, reflecting a low penetration of CFLs in the AmerenUE service area in 2008.
- Growth in electricity use in electronics is strong and reflects an increase in the saturation of electronics and the trend toward higher-powered computers and larger televisions.
- Growth in miscellaneous use is also substantial. This has been a long-term trend and assumptions have been made about growth in this end use that are consistent with the Annual Energy Outlook.

Figure 22 presents the residential end-use forecast.

Figure 22 Residential Baseline End-use Forecast

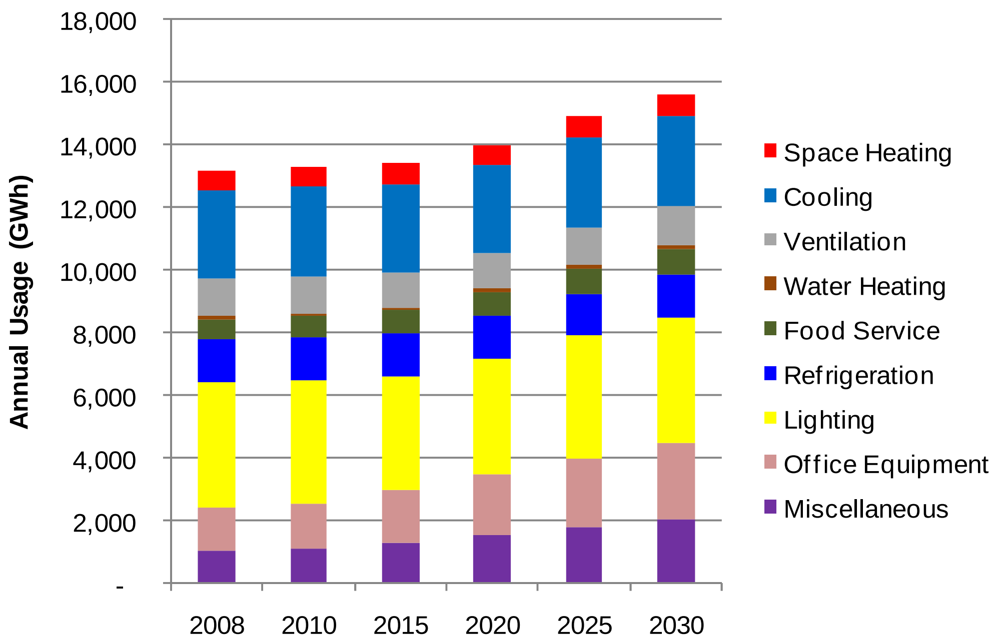


Commercial Baseline End-use Forecast

In the commercial sector, electricity use is forecast to grow from 13,178 GWh in 2008 to 15,615 GWh in 2030. This is an 18% increase over the 22 years, implying an average growth rate of 0.8%.

Figure 23 presents the forecast which shows considerable variation across the end uses. Major uses – cooling, lighting and refrigeration – are relatively flat, while significant growth takes place in office equipment and miscellaneous uses.

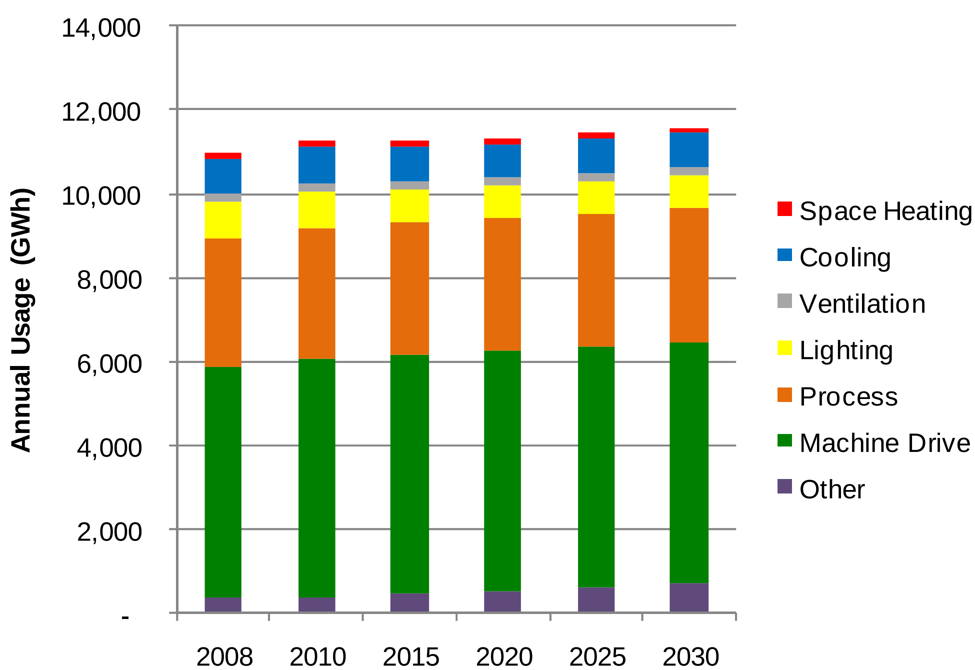
Figure 23 Commercial Baseline End-use Forecast



Industrial Baseline End-use Forecast

Industrial electricity use is projected to stay fairly flat over the next 22 years. Of course, this assumes the continued viability of AmerenUE's largest industrial customers. Electricity use is forecast to grow from 10,994 GWh in 2008 to 11,580 GWh in 2030, an increase of 5%. As in the other sectors, lighting use declines as the result of standards. The primary source of growth is in the other uses. The forecast is depicted in Figure 24.

Figure 24 Industrial Baseline End-use Forecast



POTENTIAL SAVINGS FROM ENERGY EFFICIENCY MEASURES

Once the baseline forecast was developed, analysis of energy-efficiency potential proceeded. This activity began with the identification and screening of energy-efficiency measures. A total of 299 individual measures were considered across all three sectors. The residential analysis included 118 measures, the commercial sector included 120 measures and the industrial sector considered 43 measures. The primary sources for EE measure information include:

- Global's Database of Energy Efficiency Measures (DEEM)
- California's Database of Energy Efficiency Resources (DEER database)
- AmerenUE stakeholder input

The analysis of energy-efficiency measures yielded estimates of energy efficiency for Technical and Economic potential, which were the building blocks of the subsequent program analysis and achievable potentials (see Table 1):

- **Technical potential** is the theoretical upper bound of energy-efficiency savings regardless of cost.
    1. In 2020, technical potential is 11,098 GWh, which represents 27.6% of total usage in that year.
    2. In 2030, technical potential is 12,696 GWh, 29.4% of total usage.
- **Economic potential** is an estimate of all cost-effective energy efficiency savings.
    1. In 2020, economic potential is 5,475 GWh, which represents 13.6% of total usage in that year.
    2. In 2030, economic potential is 7,181 GWh, 16.6% of total usage.

Figure 25 presents the savings as a percent of baseline energy usage in each of selected years.

Figure 25 Summary of Energy-efficiency Measure Potential

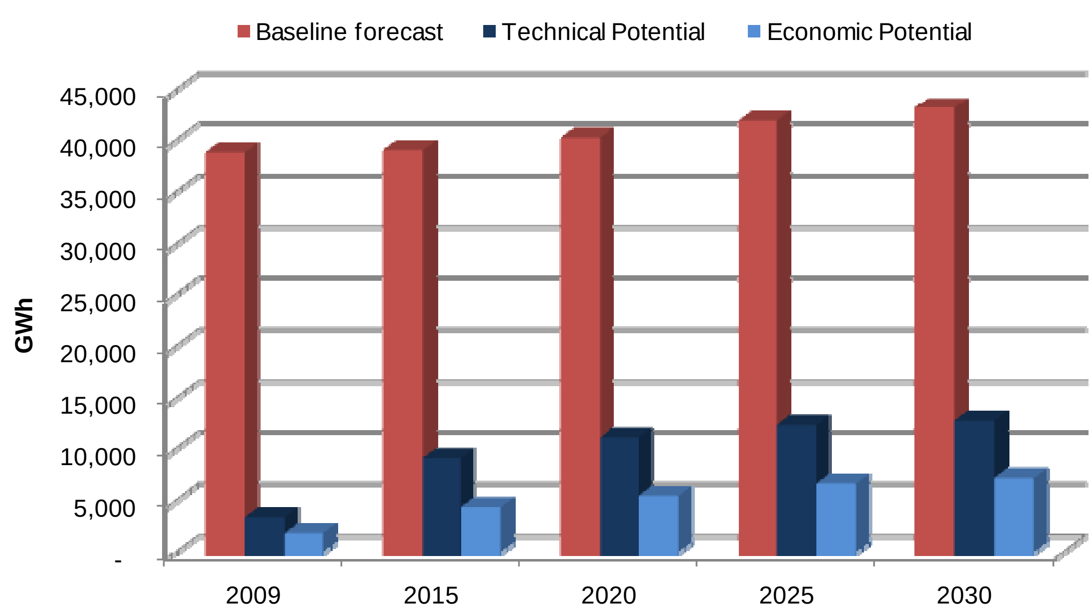
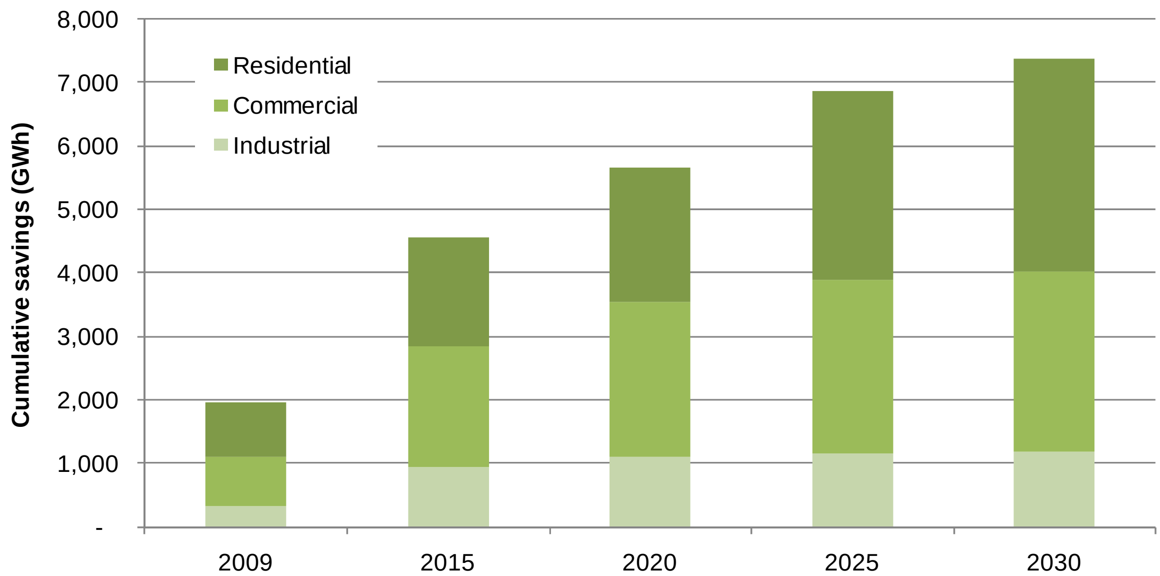


Figure 26 summarizes economic potential by sector. The contributions to savings from the residential and commercial sectors are roughly equal, while the industrial sector is the smallest of the three.

Figure 26 Summary of Economic Potential by Sector



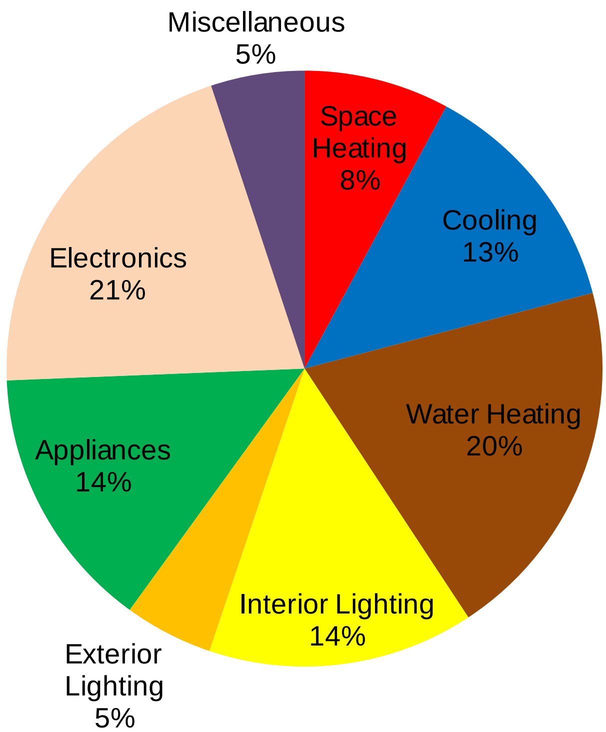
Residential EE Measure Potential

Economic potential in the residential sector in 2030 is 3,348 GWh or 21% of baseline residential usage in that year. The breakdown by end use for selected years is presented in Table 8. Figure 27, which illustrates the end-use breakdown in 2030, shows that there are substantial savings across all end uses in the residential sector, even after the effects of appliance standards.

Table 8 Residential Economic Potential by End Use

	2009	2015	2020	2030
Space Heating	66	191	214	264
Cooling	95	275	328	436
Water Heating	107	338	446	664
Interior Lighting	354	269	291	484
Exterior Lighting	135	195	164	161
Appliances	14	97	196	482
Electronics	19	205	339	688
Miscellaneous	43	123	152	170
Total	**834**	**1,692**	**2,130**	**3,348**

Figure 27 End-use Breakdown of Residential Economic Potential in 2030



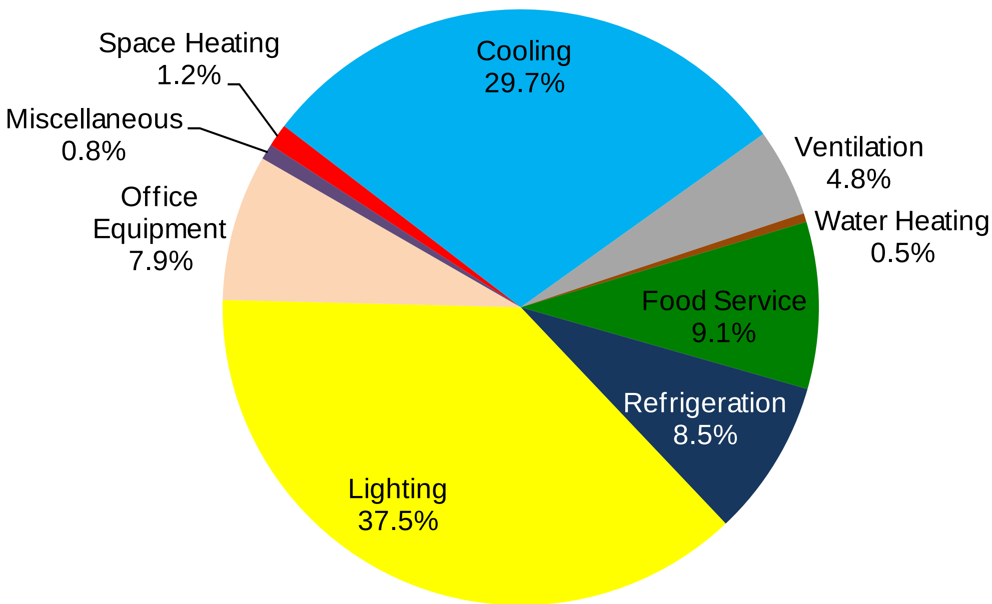
Commercial EE Measure Potential

In 2030, economic potential in the commercial sector is 2,847 GWh or 18% of baseline commercial usage in 2030. The breakdown by end use for selected years is presented in Table 9. Figure 28, which illustrates the end-use breakdown in 2030, shows that lighting and cooling account for the majority of potential savings.

Table 9 Commercial Economic Potential by End Use

	2009	2015	2020	2030
Space Heating	13	32	34	35
Cooling	196	542	679	846
Ventilation	14	95	132	136
Water Heating	2	7	10	13
Food Service	13	118	214	258
Refrigeration	14	90	152	242
Lighting	481	852	1,020	1,066
Office Equipment	42	156	178	226
Miscellaneous	2	12	20	24
Total	**777**	**1,903**	**2,441**	**2,847**

Figure 28 End-use Breakdown of Commercial Economic Potential in 2030



Industrial EE Measure Potential

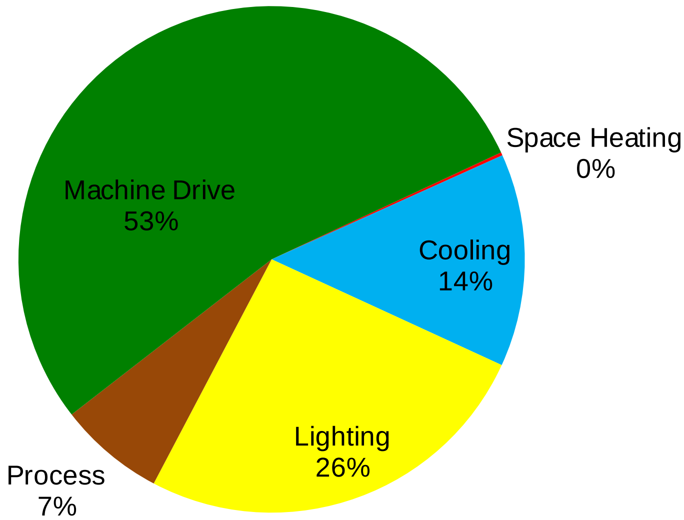
In 2030, economic potential in the industrial sector is 986 GWh or 8.5% of baseline industrial usage in 2030. The breakdown by end use for selected years is presented in Table 10.

Figure 29, which illustrates the end-use breakdown in 2030, shows that machine drives – motors and air compressors account for more than half the potential savings. However, the absolute savings from motors is relatively small for two reasons. First, there are significant savings already embodied in the baseline forecast as a result of the NEMA standards that have been in place for many years and which will begin to require that premium-grade motors be installed in December 2010. Second, industrial customers are savvy and have been able to successfully postpone motor replacement by rewinding existing motors. In addition to motors, there are significant savings opportunities in cooling, lighting and, to a lesser degree, electric processes.

Table 10 Industrial Economic Potential by End Use

	2009	**2015**	**2020**	**2030**
Space Heating	1	1	2	2
Cooling	26	63	75	134
Ventilation	-	-	-	-
Lighting	117	252	251	255
Process	25	65	67	67
Machine Drive	114	416	509	528
Total	**284**	**797**	**904**	**986**

Figure 29 End-use Breakdown of Industrial Economic Potential in 2030



DSM PROGRAM ANALYSIS

The process of developing the EE and DR programs for this study involved an assessment process that is illustrated in Figure 30. This figure depicts the sources of information that were used to guide the development of a portfolio of representative EE and DR programs that could then serve as the basis for detailed analyses, including cost-effectiveness analysis, supply curve assessment and scenario analysis. The results of these various analytics will serve as the inputs necessary for AmerenUE to conduct its current IRP assessment, work through the Missouri regulatory process and support the process of implementation.

Figure 30 Process for Developing Energy Efficiency and Demand Response Programs

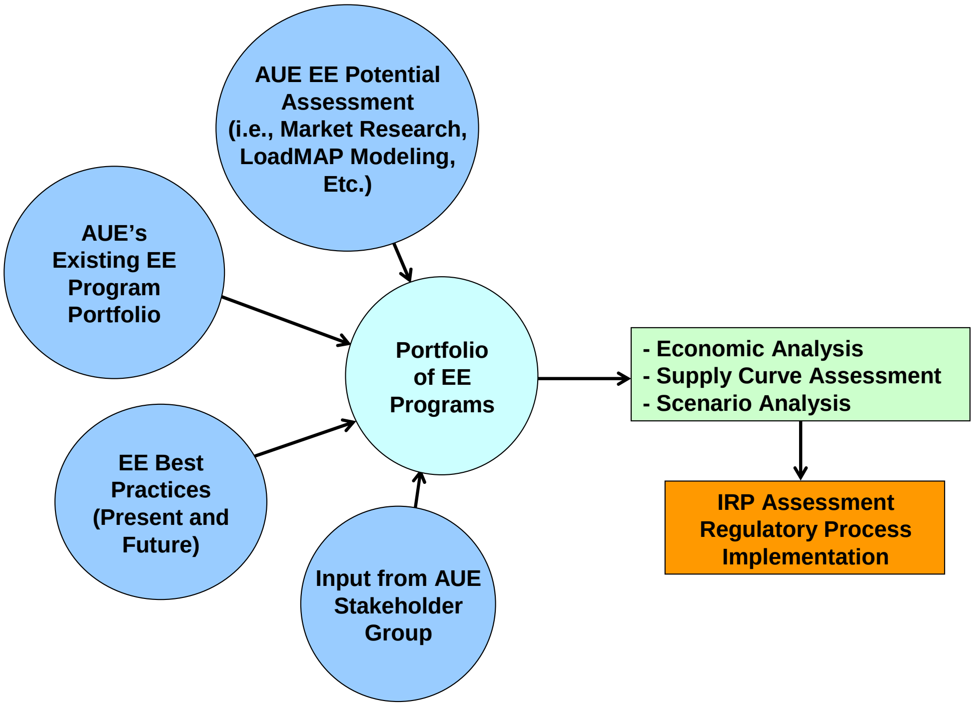


Table 11 identifies the portfolio of energy-efficiency programs considered in the analysis as well as target market segments for each. These programs reflect current industry best practices, but also provide a structure that allows the programs to adapt to meet future needs.

Figure 31 presents realistic achievable potential from energy-efficiency programs in selected years. The largest savings are found in three programs: C&I Standard Incentives, C&I Custom Incentives and Residential Lighting and Appliances

Table 11 Energy Efficiency Programs

Energy Efficiency Program	Target Market Segment(s)
1. Residential Lighting and Appliances	All residential customers
2. Multi-Family Common Area	Owners and property managers of multi-family buildings
3. Residential New Construction	Single-family new constructions
4. Residential HVAC Equipment & Diagnostics	Single-family home customers
5. Residential Energy Performance	Single-family home customers
6. Residential Low Income	Low-income residential customers
7. Residential Appliance Recycling	All residential customers
8. Residential Information/Feedback	All residential customers
9. C&I Standard Incentives	All C&I customers
10. C&I Custom Incentives	All C&I customers
11. C&I New Construction	C&I new constructions
12. C&I Retro-Commissioning	All C&I customers
13. C&I Information/Feedback	All C&I customers

Figure 31 Realistic Achievable Potential from Energy Efficiency Programs

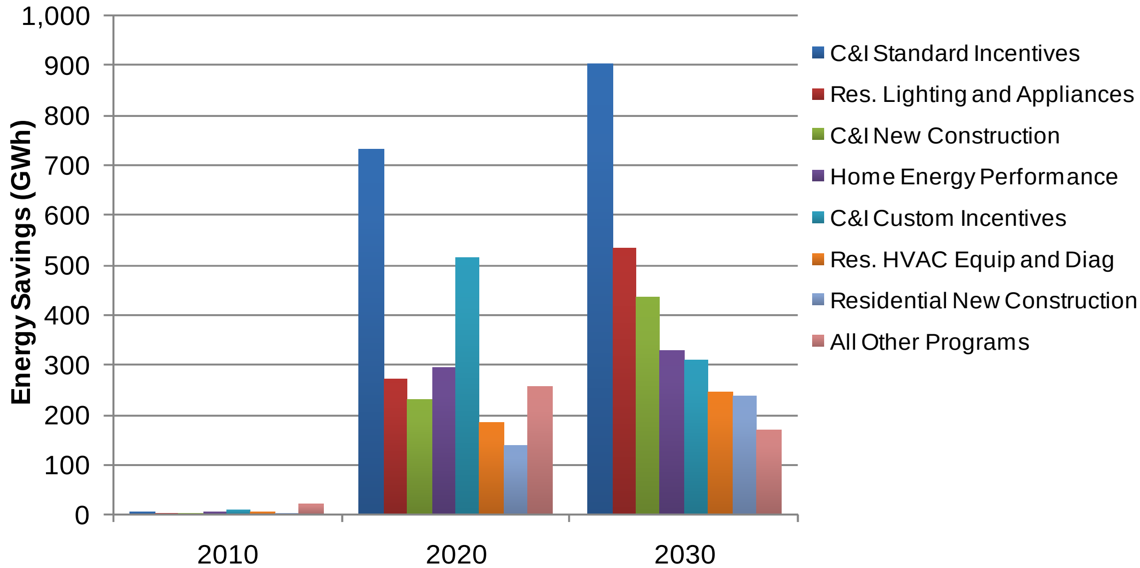
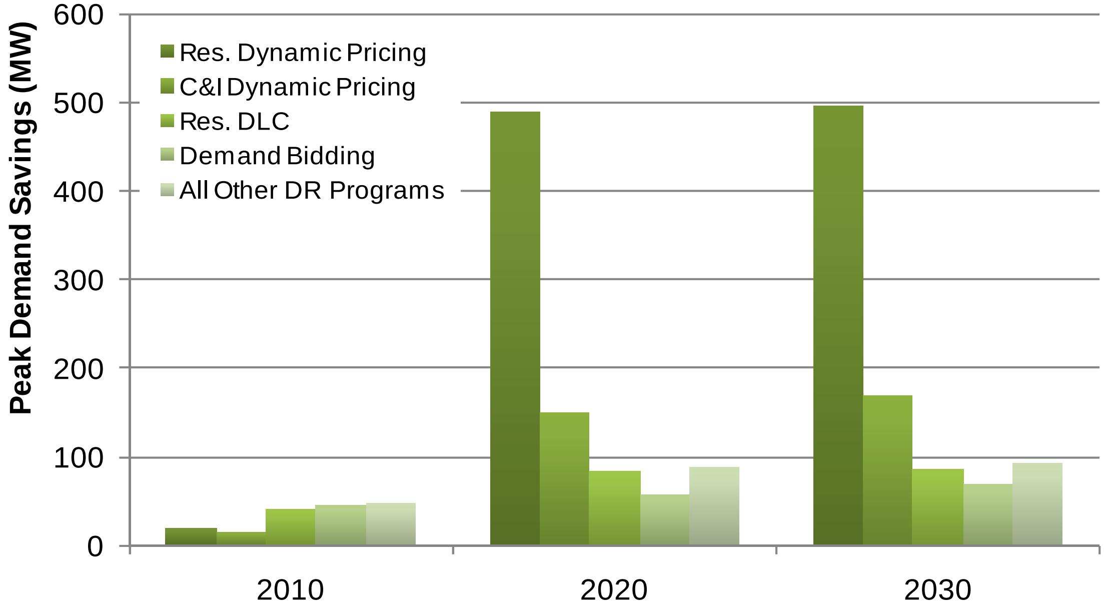


Table 12 identifies the list of demand-response programs included in the analysis together with the target segments for each. Figure 32 presents realistic achievable potential for selected years. In 2010, the majority of savings come from non-pricing programs, but by 2020 the trend is reversed and savings from dynamic pricing programs dominate.

Table 12 Demand Response Programs

Demand Response Program	Target Market Segment(s)
1. Residential Direct Load Control	All residential customers with air conditioning and electric water heating
2. Residential Dynamic Pricing	All residential customers
3. C&I Direct Load Control	All small-sized C&I customers (Rate 2M)
4. C&I Dynamic Pricing	All C&I customers (Rates 2M, 3M, 4M and 11M)
5. Demand Bidding	All medium- and large-sized C&I customers (Rates 3M, 4M and 11M)
6. Curtailable	All large-sized C&I customers (Rates 4M and 11M)
7. DR Aggregator Contracts	All C&I customers (Rates 2M, 3M, 4M and 11M)

Figure 32 Realistic Achievable Potential from Demand Response Programs



COMPARISON WITH OTHER STUDIES

The results of this AmerenUE study have been compared with three recent and relevant studies:

- The EPRI National Potential Study: ***Assessment of Achievable Potential from Energy Efficiency and Demand Response in the U.S. (2010-2030)***, TR 1016987, January 2009
- The Wisconsin Study: ***Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin, For the years 2012 and 2018***, ECW Report Number 244-1, April 2009
- The FERC Study: ***A National Assessment of Demand Response Potential***, Staff Report, June 2009

The EPRI Study

The EPRI Study assessed EE and DR potential for the U.S. and for four Census regions. AmerenUE is part of the Midwest Census region. The EPRI study has a 20-year time horizon and used a bottom-up analysis approach for the residential and commercial sectors, and a top-down approach for the industrial sector. (The AmerenUE study used a bottom-up analysis approach for all three sectors.) The base-year market characterization and the baseline end-use forecast were based on 2008 Annual Energy Outlook prepared by the Energy Information Administration. Energy-efficiency measures were comprehensive but not as extensive as the AmerenUE measure list. Market acceptance rates and program implementation factors were based on a Delphi approach with industry experts. The estimates of realistic achievable potential from this study represent a forecast of what is likely to occur and do not represent what might occur under “aggressive” utility programs. The AmerenUE parameters are based on primary market research with AmerenUE customers.

The Midwest regional results from the EPRI National Potential Study compare with AmerenUE as follows for the year 2030:

- EPRI economic potential in 2030 is 12.3%. AmerenUE economic potential is 16.6% and reflects the more extensive list of energy-efficiency measures.
- EPRI maximum achievable potential in 2030 is 10.1%, compared to the AmerenUE value of 11.0%. This reflects the lower market acceptance rates for AmerenUE based on market research.

- EPRI realistic achievable is 7.5%, compared with 7.3% for AmerenUE.

Even though the AmerenUE economic potential is higher than the EPRI study, the achievable potential estimates are in close alignment reflecting the results of the market research performed for the AmerenUE study.

The Wisconsin Study

The State of Wisconsin Study was conducted by Energy Center of Wisconsin (ECW), with subcontractors ACEEE, GDS Associates and L&S Technical Associates. It defines achievable potential not as a “middle-of-the-road” case, but rather as an upper-bound estimate of what could be achieved with aggressive utility programs. This study used a bottom-up analysis framework for the residential sector and a top-down approach for the C&I sectors. As mentioned above, market and program acceptance rates for AmerenUE are based on primary market research. The Wisconsin study used a Delphi approach to explore an aggressive energy-efficiency future in Wisconsin.

This study is regarded to be aggressive in its findings of energy-efficiency savings. Therefore, the results are compared with the RAP and MAP estimates from AmerenUE. Specifically, over a ten-year horizon, the ECW study concludes:

- Wisconsin economic potential is 18%, compared to 14% for AmerenUE.
- Wisconsin achievable potential is 13%, compared to 7% for AmerenUE RAP and 10% for AmerenUE MAP.

Given the definition of achievable potential used for the Wisconsin study and the approach for developing market acceptance rates, it is not surprising that the Wisconsin estimates of achievable potential are higher than the AmerenUE estimates.

The FERC Study

In 2008-2009, FERC conducted its first assessment of demand-response potential. The analysis was performed for each of the 50 states and the District of Columbia and aggregated to regional and national totals. The results reflect a bottom-up analysis approach that relies on secondary data from a variety of resources.

The definition of achievable potential for the FERC study is similar to that used for the Wisconsin EE study in that it is an aggressive perspective. Specifically, achievable potential is defined as what could be achieved over a ten-year horizon if advanced metering infrastructure (AMI) were deployed universally, dynamic pricing were the default tariff, and other DR programs, such as direct load control, were available to those who opted out of dynamic pricing. The FERC study also estimated an “expanded business as usual” scenario which represents expansion of current programs to all states and with higher participation rates, partial AMI deployment, and optional dynamic pricing tariffs. Participation rates are based on secondary data and expert judgment, whereas the AmerenUE rates are based on primary market research and expert judgment.

The FERC study provides the following estimates for the state of Missouri:

- FERC achievable potential is 19.2%, compared with 11.9% for maximum achievable for AmerenUE
- FERC expanded BAU is 14.1%, compared with 9.6% for realistic achievable potential for AmerenUE.

Since the definition of achievable potential in the FERC study is more aggressive (or optimistic) than that used for the AmerenUE study, it is not surprising that estimates of achievable potential are higher than the AmerenUE estimates.

ABOUT GLOBAL

Established in 1998, Global Energy Partners, LLC is a premier provider of energy and environmental engineering and technical services to utilities, energy companies, research organizations, government/regulatory agencies and private industry.

Global's offerings range from strategic planning to turn-key program design and implementation and technology applications.

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AmerenUE DSM Cost Recovery Examples
Forecast Expense Tracker
(Dollars in Millions)

Example of Under-Collection

	Rate Case Filed 2010	2011	2012	Rate Case Filed 2013	2014	2015
1 DSM Program Expenses from Implementation Plan		46	54	56	57	61
2 2-year Forecast Average Expense	50			59		
3 Expenses Collected		50	50	50	59	59
4 Actual DSM Program Expenses		**47**	**56**	56	57	60
5 Amount Over/(Under)-Collected (line 3 - line 4)		3	(6)	(6)	2	(1)
6 Over/(Under)-Recovery Regulatory Asset Balance		3	(3)	(9)	(6)	(6)
7 Over/(Under)-Recovery Amount to be Amortized				(3)		
8 Amortization of Over/(Under)-Recover Amount (3-year amortization beginning when new rates are effective)					1	1
9 Total Collections Related to Forecast Expense Tracker (line 3 + line 8)		50	50	50	60	60

Example of Over-Collection

	Rate Case Filed 2010	2011	2012	Rate Case Filed 2013	2014	2015
1 DSM Program Expenses from Implementation Plan		46	54	56	57	61
2 2-year Forecast Average Expense	50			59		
3 Expenses Collected		50	50	50	59	59
4 Actual DSM Program Expenses		**42**	**52**	56	57	60
5 Amount Over/(Under)-Collected (line 3 - line 4)		8	(2)	(6)	2	(1)
6 Over/(Under)-Recovery Regulatory Asset Balance		8	6	-	-	(3)
7 Over/(Under)-Recovery Amount to be Amortized				6		
8 Amortization of Over/(Under)-Recover Amount (3-year amortization beginning when new rates are effective)					(2)	(2)
9 Total Collections Related to Forecast Expense Tracker (line 3 + line 8)		50	50	50	57	57

Note: Examples ignore the accrual of carrying costs during accumulation and return during amortization for simplicity.

Aligning Utility Incentives with Investment in Energy Efficiency

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2007

SMK-ER4-1

About This Document

This report on *Aligning Utility Incentives with Investment in Energy Efficiency* is provided to assist gas and electric utilities, utility regulators, and others in the implementation of the recommendations of the National Action Plan for Energy Efficiency (Action Plan) and the pursuit of its longer-term goals.

The Report describes the financial effects on a utility of its spending on energy efficiency programs, how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency, and how adoption of various policy mechanisms can reduce or eliminate these barriers. The Report also provides a number of examples of such mechanisms drawn from the experience of utilities and states.

The primary intended audiences for this paper are utilities, state policy-makers, and energy efficiency advocates interested in specific options for addressing the financial barriers to utility investment in energy efficiency.

Aligning Utility Incentives with Investment in Energy Efficiency

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2007

SMK-ER4-3

Aligning Utility Incentives with Investment in Energy Efficiency is a product of the National Action Plan for Energy Efficiency Leadership Group and does not reflect the views, policies, or otherwise of the federal government. The role of the U.S. Department of Energy and U.S. Environmental Protection Agency is limited to facilitation of the Action Plan.

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List of Abbreviations and Acronyms

A

APS Arizona Public Service Company

B

BA balance adjustment

BGE Baltimore Gas & Electric

BGSS Basic Gas Supply Service

C

CCRA conservation cost recovery adjustment

CCRC conservation cost recovery charge

CET conservation enabling tariff

CIP conservation improvement program or Conservation Incentive Program

CMP Central Maine Power

CPUC California Public Utilities Commission

CUA conservation and usage adjustment

D

DBA DSM balance adjustment

DCR DSM program cost recovery

DNG distribution non-gas

DOE U.S. Department of Energy

DRLS DSM revenue from lost sales

DSM demand-side management

DSMI DSM incentive

DSMRC demand-side management recovery component

E

ECCR energy conservation cost recovery

EPA U.S. Environmental Protection Agency

ER earnings rate

ERAM electric rate adjustment mechanism

F

FCA fixed cost adjustment

FCM forward capacity market

FEECA Florida Energy Efficiency and Conservation Act

FPL Florida Power and Light

H

HECO Hawaiian Electric Company

I

ISO independent system operator

K

kW kilowatt

kWh kilowatt-hour

L

LG&E Louisville Gas & Electric

LRAM lost revenue adjustment mechanism

M

MW megawatt

MWh megawatt-hour

List of Abbreviations and Acronyms (continued)

N

NARUC	National Association of Regulatory Utility Commissioners
NJNG	New Jersey Natural Gas
NJR	New Jersey Resources
NJRES	NJR Energy Services
NSP	Northern States Power Company

O

O&M	operation and maintenance

P

PBR	performance-based ratemaking
PEB	performance earnings basis
PG&E	Pacific Gas & Electric Company

R

RAP	Regulatory Assistance Project
ROE	return on equity

S

SFV	Straight Fixed-Variable
SJG	South Jersey Gas

U

UCE	Utah Clean Energy

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This report on Aligning Utility Incentives with Investment in Energy Efficiency is a key product of the Year Two Work Plan for the National Action Plan for Energy Efficiency. This work plan was developed based on feedback received from Action Plan Leadership Group members and observers during fall 2006. The work plan was further refined during the March 2007 Leadership Group meeting in Washington, D.C. A full list of Leadership Group members is provided in Appendix A.

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- Lynn Anderson, Idaho Public Service Commission
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Executive Summary

This report on Aligning Utility Incentives with Investment in Energy Efficiency describes the financial effects on a utility of its spending on energy efficiency programs, how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency, and how adoption of various policy mechanisms can reduce or eliminate these barriers. The Report also provides a number of examples of such mechanisms drawn from the experience of utilities and states. The Report is provided to assist in the implementation of the National Action Plan for Energy Efficiency's five key policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which collectively consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Aligning the financial incentives of utilities with the delivery of cost-effective energy efficiency supports the key role utilities can play in capturing energy savings.

This Report has been developed to help parties fully implement the five key policy recommendations of the National Action Plan for Energy Efficiency. (See Figure 1-1 for a full list of options to consider under each Action Plan recommendation.) The Action Plan was released in July 2006 as a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level.

This Report directly supports the Action Plan recommendations to "provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective" and "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Key options to consider under this recommendation include committing to a consistent way to recover costs in a timely manner, addressing the typical utility throughput incentive and providing utility incentives for the successful management of energy efficiency programs.

There are a number of possible regulatory mechanisms for addressing these issues. Determining which mechanism will work best for any given jurisdiction is a process that takes into account the type and financial structure of the utilities in that jurisdiction; existing statutory and regulatory authority; and the size of the energy efficiency investment. The net impact of an energy efficiency cost recovery and performance incentives policy will be affected by a wide variety of other rate design, cost recovery, and resource procurement strategies, as well as broader considerations, such as the rate of demand growth and environmental and resource policies.

The Financial and Policy Context

Utility spending on energy efficiency programs can affect the utility's financial position in three ways: (1) through recovery of the direct costs of the programs; (2) through the impact on utility earnings of reduced

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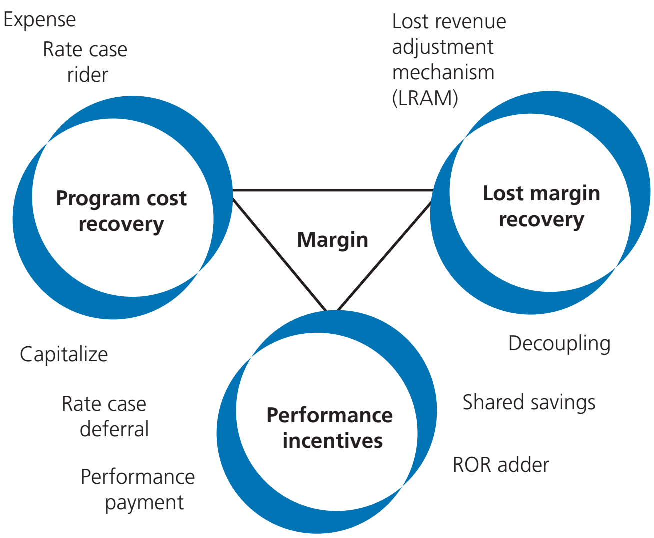
sales; and (3) through the effects on shareholder value of energy efficiency spending versus investment in supply-side resources. The relative importance of each effect to a utility is measured by its impact on earnings. A variety of mechanisms have been developed to address these impacts, as illustrated in Figure ES-1.

Figure ES-1. Cost Recovery and Performance Incentive Options



How these impacts are addressed creates the incentives and disincentives for utilities to pursue energy efficiency investment. The relative importance of each of these depends on specific context—the impacts of energy efficiency programs will look different to gas and electric utilities, and to investor-owned, publicly owned, and cooperatively owned utilities. Comprehensive policies addressing all three levels of impact generally are considered more effective in spurring utilities to pursue efficiency aggressively. Ultimately, however, it is the cumulative net effect on utility earnings or net income of a policy that will determine the alignment of utility financial interests with energy efficiency investment. The same effect can be achieved in different ways, not all of which will include explicit mechanisms for each level. Chapter 2 of this Report explores the financial effects of and policy issues associated with utility energy efficiency spending.

Program Cost Recovery

The most immediate impact is that of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants. Reasonable opportunity for program cost recovery is a necessary condition for utility program spending, as failure to recover these costs produces a direct dollar-for-dollar reduction in utility earnings, all else being equal, and sends a discouraging message regarding further investment.

Policy-makers have a wide variety of tools available to them within the broad categories of expensing and capitalization to address cost recovery. Program costs can be recovered as expenses or can be treated like capital items by accruing program costs with carrying charges, and then amortizing the balances with recovery over a period of years. Chapter 4 reviews both general options as well as several approaches for the tracking, accrual, and recovery of program costs. Case studies for Arizona, Iowa, Florida, and Nevada are presented to illustrate the actual application of the mechanisms.

Each of these tools can have different financial impacts, but the key factors in any case are the determination of the prudence of program expenditures and the timing of cost recovery. How each of these is addressed will affect the perceived financial risk of the policy. The more uncertain the process for determining the prudence of expenditures, and the longer the time between an expenditure and its recovery, the greater the perceived financial risk and the less likely a utility will be to aggressively pursue energy efficiency.

Lost Margin Recovery and the Throughput Incentive

The second impact, sometimes called the lost margin recovery issue is the effect on utility financial margins caused by the energy efficiency-produced drop in sales. Utilities incur both fixed and variable costs. Fixed costs include a return of (depreciation) and a return on (interest plus earnings) capital (a utility's physical infrastructure), as well as property taxes and certain operation and maintenance (O&M) costs. These costs do not vary as a function of sales in the short-run. However, most utility rate designs attempt to recover a portion of these fixed costs through volumetric prices—a price per kilowatt-hour or per therm. These prices are based on an estimate of sales: price = revenue requirement/ sales.1 If actual sales are either higher or lower than the level estimated when prices are set, revenues will be higher or lower. All else being equal, if an energy efficiency program reduces sales, it reduces revenues proportionately, but fixed costs do not change. Less revenue, therefore, means that the utility is at some risk for not recovering all of its fixed costs. Ultimately, the drop in revenue will impact the utility's earnings for an investor-owned utility, or net operating margin for publicly and cooperatively owned utilities.

Few energy efficiency policy issues have generated as much debate as the issue of the impact of energy efficiency programs on utility margins. Arguments on all sides of the lost margin issue can be compelling. Many observers would agree that significant and sustained investment in energy efficiency by utilities, beyond that required under statute or order, will not occur without implementation of some type of mechanism to ensure recovery of lost margins. Others argue that the lost margin issue cannot be treated in isolation; margin recovery is affected by a wide variety of factors, and special adjustments for energy efficiency constitute single issue ratemaking.[2]

Care should be taken to ensure that two very different issues are not incorrectly treated as one. The first issue is whether a utility should be compensated for the under-recovery of fixed costs when energy efficiency programs or events outside of the control of the utility (e.g., weather or a drop in economic activity) reduce sales below the level on which current rates are based. *Lost revenue adjustment mechanisms* (LRAMs) have been designed to estimate and collect the margin revenues that might be lost due to a successful energy efficiency program. These mechanisms compensate utilities for the effect of reduced sales due to efficiency, but they do not change the linkage between sales and profit. Few states currently use these mechanisms.

The second issue is whether potential lost margins should be addressed as a stand-alone matter of cost recovery or by *decoupling* revenues from sales—an approach that fundamentally changes the relationship between sales and revenues, and thus margins. Decoupling not only addresses lost margin recovery, but also removes the throughput incentive—the incentive for utilities to promote sales growth, which is created when fixed costs are recovered through volumetric charges. The *throughput incentive* has been identified by many as the primary barrier to aggressive utility investment in energy efficiency.

Chapter 5 examines the cause of and options for recovery of lost margins, and case studies are presented for decoupling in Idaho, New Jersey, Maryland, and Utah, and for the application of a LRAM in Kentucky.

Utility Performance Incentives

The two impacts described above pertain to potential direct disincentives for utilities to engage in energy efficiency program investment. The third impact concerns incentives for utilities to undertake such investment. Under traditional regulation, investor-owned utilities earn returns on capital invested in generation, transmission, and distribution. Unless given the opportunity to profit from the energy efficiency investment that is intended to substitute for this capital investment, there is a clear financial incentive to prefer investment in supply-side assets, since these investments contribute to enhanced shareholder value. Providing financial incentives to a utility if it performs well in delivering energy efficiency can change that business model by making efficiency profitable rather than merely a break-even activity.

The three major types of performance mechanisms have been most prevalent include:

- Performance target incentives.
- Shared savings incentives.
- Rate of return adders.

Performance target incentives provide payment—often a percentage of the total program budget—for achievement of specific metrics, usually including savings targets. Most states providing such incentives set performance ranges; incentives are not paid unless a utility achieves some minimum fraction of proposed savings, and incentives are capped at some level above projected savings.

Shared savings mechanisms provide utilities the opportunity to share with ratepayers the net benefits resulting from successful implementation of energy efficiency programs. These structures also include specific performance targets that tie the percentage of net savings awarded to the percentage of goal achieved. Some, but not all, shared savings mechanisms include penalty provisions requiring utilities to pay customers when minimum performance targets are not achieved.

Rate of return adders provide an increase in the return on equity (ROE) applied to capitalized energy efficiency expenditures. This approach currently is not common as a performance incentive for several reasons. First, this mechanism requires energy efficiency program costs to be capitalized, which relatively few utilities prefer. Second, at least as applied in several cases, the adder is not tied to performance—it simply is applied to all capitalized energy efficiency costs as a way to broadly incent a utility for efficiency spending. On the other hand, capitalization, in theory, places energy efficiency on more equal financial terms with supply-side investments to begin with. Thus, any adder could be viewed more as a risk-premium for investment in a regulatory asset.

The premise that utilities should be paid incentives as a condition for effective delivery of energy efficiency programs is not universally accepted. Some argue that utilities are obligated to pursue energy efficiency if that is the policy of a state, and that performance incentives require customers to pay utilities to do something that they should do anyway. Others have argued more directly that the basic business of a utility is to deliver energy, and that providing financial incentives over-and-above what could be earned by efficient management of the supply business simply raises the cost of service to all customers and distorts management behavior.

Chapter 6 reviews these mechanisms in greater detail and provides case studies drawn from Massachusetts, Minnesota, Hawaii, and California.

Table ES-1 summarizes the current level of state activity with regard to the financial mechanisms describe above.

Understanding Objectives—Developing Policy Approaches That Fit

The overarching goal in every jurisdiction that considers an energy efficiency investment policy is to generate and capture substantial net economic benefits. Achieving this goal requires aligning utility financial interests with investment in energy efficiency. The right combination of cost recovery and performance incentive mechanisms to support this alignment requires a balancing of a variety of more specific objectives common to the ratemaking process. Chapter 3 reviews how these objectives might influence design of a cost recovery and performance incentive policy, and highlights elements of the policy context that will affect policy design. Each of these objectives are not given equal weight by policy-makers, but most are given at least some consideration in virtually every discussion of cost recovery and performance incentives.

- **Strike an Appropriate Balance of Risk/Reward Between Utilities/Customers.** If a mechanism is well-designed and implemented, customer benefits will be large enough to allow sharing some of this benefit as a way to reduce utility risk and strengthen institutional commitment; all parties will be better off than if no investment had been made.
- **Promote Stabilization of Customer Rates and Bills.** While it is prudent to explore policy designs that, among available options, minimize potential rate volatility, the pursuit of rate stability should be balanced against the broader interest of lowering the overall cost of providing electricity and natural gas.
- **Stabilize Utility Revenues.** Even if cost recovery policy covers program costs, fixed cost recovery and performance incentives, how this recovery takes

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Table ES-1. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Alabama	Yes					
Alaska						
Arizona	Yes (electric)	Yes (electric)		Pending (gas)		Yes (electric)
Arkansas				Yes (gas)		
California	Yes	Yes		Yes		Yes
Colorado	Yes		Yes	Pending		Yes
Connecticut		Yes (electric)			Yes	Yes
Delaware	Yes			Pending		
District of Columbia	Yes			Pending (electric)		
Florida			Yes (electric)			
Georgia	Yes					Yes (electric)
Hawaii				Pending (electric)		Yes
Idaho	Yes (electric)			Yes (electric)		
Illinois	Yes (electric)					
Indiana	Yes			Yes (gas)	Yes	Yes
Iowa	Yes		Yes			
Kansas						Yes
Kentucky			Yes	Pending (gas)	Yes	Yes
Louisiana						
Maine		Yes (electric)				
Maryland				Yes (gas) Pending (electric)		
Massachusetts		Yes (electric)		Pending (electric)	Yes	Yes (electric)
Michigan				Pending (gas)		
Minnesota	Yes			Yes		Yes
Mississippi	Yes					
Missouri				Yes (gas)		
Montana	Yes (gas)	Yes (electric)				Yes
Nebraska						
Nevada	Yes (electric)			Yes (gas)		Yes (electric)
New Hampshire		Yes (electric)		Pending (electric)		Yes (electric)

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Table ES-1. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities (continued)

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
New Jersey		Yes		Yes (gas) Pending (electric)		
New Mexico	Yes			Pending (gas)		
New York		Yes (electric)		Yes		
North Carolina				Yes (gas)		
North Dakota						
Ohio			Yes (electric)	Yes (gas)	Yes (electric)	Yes (electric)
Oklahoma						
Oregon		Yes		Yes (gas)		
Pennsylvania	Yes					
Rhode Island		Yes (electric)		Yes		Yes
South Carolina						Yes
South Dakota						
Tennessee						
Texas	Yes					
Utah	Yes (electric)		Yes (electric)	Yes (gas)		
Vermont		Yes (electric)			Yes	Yes
Virginia				Pending (gas)		
Washington	Yes (electric)		Yes (electric)	Yes (gas)		
West Virginia						
Wisconsin	Yes (electric)	Yes (electric)		Pending (electric)		
Wyoming						

Source: Kushler et al., 2006. (Current as of September 2007.) Please see Appendix C for specific state citations.

place can affect the pattern of cash flow and earnings. Large episodic jumps in earnings (produced, for example, by a decision to allow recovery of accrued under-recovery of fixed costs in a lump sum), can cloud financial analysts' ability to discern the true financial performance of a company.

- **Administrative Simplicity and Managing Regulatory Costs.** Simplicity requires that any/all mechanisms be transparent with respect to both calculation of recoverable amounts and overall impact on utility earnings. Every mechanism will impose some incremental cost on all parties, since some regulatory responsibilities are inevitable. The objective, therefore, is to structure mechanisms that lend themselves to a consistent and more formulaic process. This objective can be satisfied by providing clear rules prescribing what is considered acceptable/necessary as part of an investment plan.

Finding the right policy balance hinges on a wide range of factors that can influence how a cost recovery and performance incentive measure will actually work. These factors will include: industry structure (gas or electric utility, public or investor-owned, restructured or bundled); regulatory structure and process (types of test year, current rate design policies); and utility operating environment (demand growth and volatility, utility cost and financial structure, structure of the energy efficiency portfolio). Given the complexity of many of these issues, most states defer to state utility regulators to fashion specific cost recovery and performance incentive mechanism(s).

Emerging Models

Although the details of the policies and mechanisms for addressing the financial impacts of energy efficiency programs continue to evolve in jurisdictions across the country, the basic classes of mechanisms have been understood, applied, and debated for more than two decades. Most jurisdictions currently considering policies to remove financial disincentives to utility investment in energy efficiency are considering one or more of the mechanisms described above. Still, the persistent debate over recovery of lost margins and performance incentives in particular creates an interest in new approaches.

In April 2007, Duke Energy proposed what is arguably the most sweeping alternative to traditional cost recovery, margin recovery and performance incentive approaches since the 1980s. Offered in conjunction with an energy efficiency portfolio in North Carolina, Duke's Energy Efficiency Rider encapsulates program cost recovery, recovery of lost margins, and shareholder incentives into one conceptually simple mechanism tied to the utility's avoided cost. The approach is based on the notion that, if energy efficiency is to be viewed from the utility's perspective as equivalent to a supply resource, the utility should be compensated for its investment in energy efficiency by an amount roughly equal to what it would otherwise spend to build the new capacity that is to be avoided. The Duke proposal would authorize the company, "to recover the amortization of and a return on 90 percent of the costs avoided by producing save-a-watts."

The proposal clearly represents an innovation in thinking regarding elimination of financial disincentives for utilities, and has intuitive appeal for its conceptual simplicity. The Duke proposal does represent a distinct departure from cost recovery and shareholder incentives convention. What is a simple and compelling concept is embedded in a formal mechanism that is quite complex, and the mechanism will likely engender substantial debate.

A second emerging model is represented by the ISO New England's capacity auction process. This process allows demand-side resources to be bid into an auction alongside supply-side resources, and utilities and third-party energy efficiency providers are allowed to participate in the auction with energy efficiency programs. Winning bids receive a revenue stream that could, under certain circumstances, be used to offset direct program costs or lost margins, or could provide a source of performance incentives. The treatment of revenues received from the auction by a utility, however, is subject to allocation by its state utility commission(s), and the traditional approach to the treatment of off-system revenues is to credit them against jurisdictional revenue requirements. Therefore, the capability of this model to address the impacts described above depends largely on state regulatory policy. Whether this model ultimately is transferable to other areas of the country depends greatly on how power markets are structured in these areas.

Final Thoughts

The history of utility energy efficiency investment is rich with examples of how state legislatures, regulatory commissions, and the governing bodies of publicly and cooperatively owned utilities have explored their cost recovery policy options. As these options are reconsidered and reconfigured in light of the trend toward higher utility investment in energy efficiency, this experience yields several lessons with respect to process.

- **Set cost recovery and incentive policy based on the direction of the market's evolution.** The rapid development of technology, the likely integration of energy efficiency and demand response, continuing evolution of utility industry structure, the likelihood of broader action on climate change, and a wide range of other uncertainties argue for cost recovery and incentive policies that can work with intended effect under a variety of possible futures.

- **Apply cost recovery mechanisms and utility performance incentives in a broad policy context.** The policies that affect utility investment in energy efficiency are many and varied and each will control, to some extent, the nature of financial incentives and disincentives that a utility faces. Policies that could impact the design of cost recovery and incentive mechanisms include those having to do with carbon emissions reduction; non-CO2 environmental control, such as NOX cap-and-trade initiatives; rate design; resource portfolio standards; and the development of more liquid wholesale markets for load reduction programs.

- **Test prospective policies.** Complex mechanisms that have many moving parts cannot easily be understood unless the performance of the mechanisms is simulated under a wide range of conditions. This is particularly true of mechanisms that rely on projections of avoided costs, prices, or program impacts. Simulation of impacts using financial modeling and/or use of targeted pilots can be effective tools to test prospective policies.

- **Policy rules must be clear.** There is a clear link between the risk a utility perceives in recovering its costs, and disincentives to invest in energy efficiency. This risk is mitigated in part by having cost recovery and incentive mechanisms in place, but the efficacy of these mechanisms depends very much on the rules governing their application. While state regulatory commissions often fashion the details of cost recovery, lost margin recovery, and performance incentive mechanisms, the scope of their actions is governed by legislation. In some states, significant expenditures on energy efficiency by utilities are precluded by lack of clarity regarding regulators' authority to address one or more of the financial impacts of these expenditures. Legislation specifically authorizing or requiring various mechanisms creates clarity for parties and minimizes risk.

- **Collaboration has value.** The most successful and sustainable cost recovery and incentive policies are those that are based on a consultative process that, in general, includes broad agreement on the aims of the energy efficiency investment policy.

- **Flexibility is essential.** Most of the states that have had significant efficiency investment and cost recovery policies in place for more than a few years have found compelling reasons to modify these policies at some point. These changes reflect an institutional capacity to acknowledge weaknesses in existing approaches and broader contextual changes that render prior approaches ineffective. Policy stability is desirable, and policy changes that have significant impacts on earnings or prices can be particularly challenging. However, it is the stability of impact rather than adherence to a particular model that is important in addressing financial disincentives to invest.

- **Culture matters.** One important test of a cost recovery and incentives policy is its impact on corporate culture. A policy providing cost recovery is an essential first step in removing financial disincentives associated with energy efficiency investment, but it will not change a utility's core business model. Earnings are still created by investing in supply-side assets and selling more energy. Cost recovery plus a policy enabling recovery of lost margins might make a utility indifferent to selling or saving a kilowatt-hour or therm, but still will not make the business case for aggressive pursuit of energy efficiency. A full complement of cost recovery, lost margin recovery, and performance incentive mechanisms can change this model, and likely will be needed to secure sustainable funding for energy efficiency at levels necessary to fundamentally change resource mix.

Notes

1. Revenue requirement refers to the sum of the costs that a utility is authorized to recover through rates.

2. For example, see the National Association of State Utility Consumer Advocates' Resolution on Energy Conservation and Decoupling, June 12, 2007.

1: Introduction

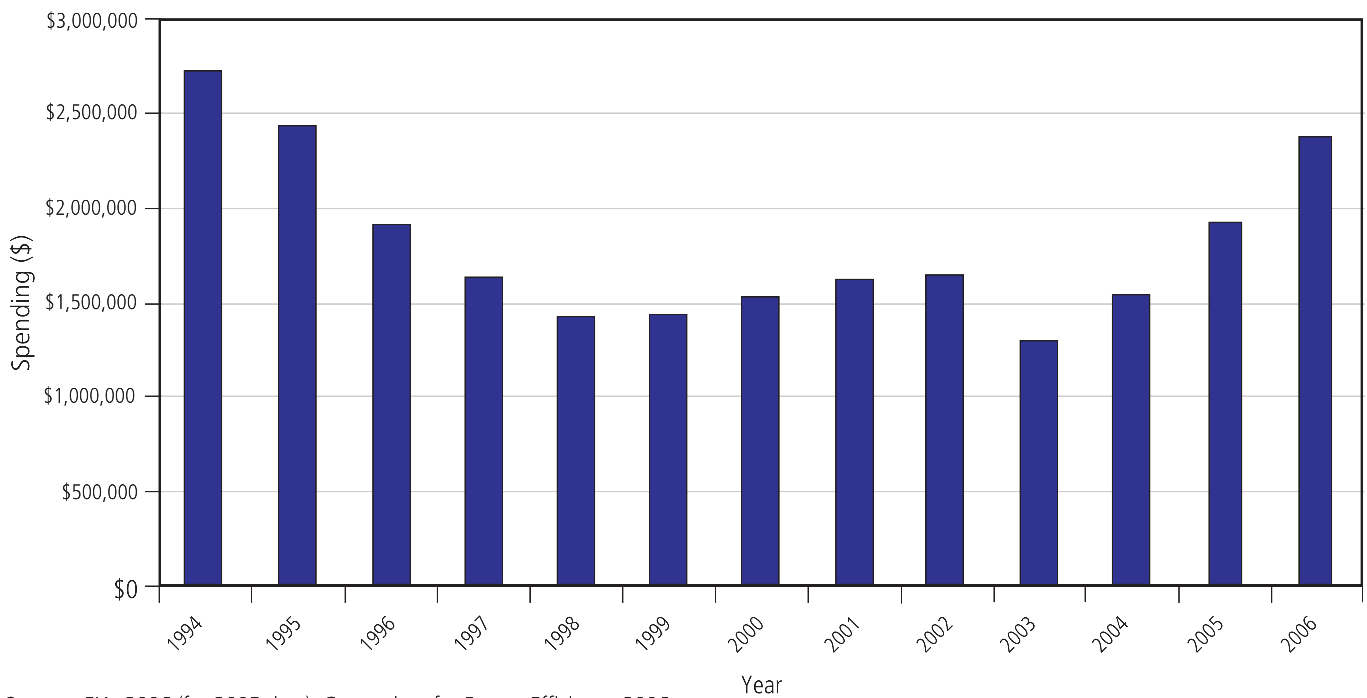
Improving the energy efficiency of homes, businesses, schools, governments, and industries—which collectively consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants.[1]

Recognizing this large untapped opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency.[2] The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency; outlines five key policy recommendations for achieving all cost-effective energy efficiency, focusing largely on state-level energy efficiency policies and programs; and provides a number of options to consider in pursuing these recommendations (Figure 1-1). As of November 2007, nearly 120 organizations have endorsed the Action Plan recommendations and made public commitments to implement them in their areas. Aligning utility incentives with the delivery of cost-effective energy efficiency is key to making the Action Plan a reality.

1.1 Energy Efficiency Investment

Actual and prospective investment in energy efficiency programs is on a steep climb, driven by a variety of resource, environmental, and customer cost mitigation concerns. Nevada Power is proposing substantial increases in energy efficiency funding as a strategy for

Figure 1-1. Annual Utility Spending on Electric Energy Efficiency



Sources: EIA, 2006 (for 2005 data); Consortium for Energy Efficiency, 2006.

Figure 1-2. National Action Plan for Energy Efficiency Recommendations and Options

Recognize energy efficiency as a high-priority energy resource.

Options to consider:

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.

Options to consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust measurement and verification procedures.
- Designating which organization(s) is responsible for administering the energy efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Broadly communicate the benefits of and opportunities for energy efficiency.

Options to consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level, addressing relevant customer, utility, and societal perspectives.
- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.
- Communicating the role of building codes, appliance standards, and tax and other incentives.

Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

Options to consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options, such as revenue requirement or resource procurement funding, system benefits charges, rate-basing, shared-savings, and incentive mechanisms.
- Establishing funding for multi-year period.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Options to consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.
- Providing utility incentives for the successful management of energy efficiency programs.
- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.
- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.
- Adopting rate designs that encourage energy efficiency by considering the unique characteristics of each customer class and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit-sharing programs and on-bill financing.

Source: National Action Plan for Energy Efficiency, 2006a.

compliance with the state's aggressive resource portfolio standard. Funding in California has roughly doubled since 2004 as utilities supplement public charge monies with "procurement funds."[3] Michigan and Illinois have been debating significant efficiency funding requirements, and the Texas legislature has doubled the percentage of load growth that must be offset by energy efficiency, implying a significant increase in efficiency program funding. Integrated resource planning cases and various regulatory settlements from Delaware to North Carolina and Missouri are producing new investment in energy efficiency. Data recently compiled by the Consortium for Energy Efficiency (2006) show total estimated energy efficiency spending by electric utilities exceeding $2.3 billion in 2006, on par with peak energy efficiency spending in the mid-1990s. With the rise in funding, there is broad interest across the country in refashioning regulatory policies to eliminate financial disincentives and barriers to utility investment in energy efficiency.

1.1.1 Understanding Financial Disincentives to Utility Investment

Not unexpectedly, the rise in interest in energy efficiency investment has produced a resurgent interest in how the costs associated with energy efficiency programs are recovered, and whether, in the light of what many believe to be compelling reasons for greater program spending, utilities have sufficient incentive to aggressively pursue these investments.

Energy efficiency programs can have several financial impacts on utilities that create disincentives for utilities to promote energy efficiency more aggressively. Policymakers have developed several mechanisms intended to minimize or eliminate these impacts.

Utility concerns for these three impacts have had a profound effect on energy efficiency investment policy at the corporate and state level for over 20 years, and the concerns continue to create tension as utilities are called upon to boost energy efficiency spending.

Although the nature of today's cost recovery and incentives discussion may be reminiscent of a similar discussion almost two decades ago, the context in which this discussion is taking place is very different. Not only have parties gained valuable experience related to the use of various cost recovery and incentive mechanisms, but the policy landscape has also been reshaped fundamentally.

Industry Structure

The past two decades have witnessed significant industry reorganization in both wholesale and retail power and natural gas markets. Investor-owned electric utilities, particularly in the Northeast and sections of

Table 1-1. Utility Financial Concerns

Potential Impact	Potential Solutions
Energy efficiency expenditures adversely impact utility cash flow and earnings if not recovered in a timely manner.	• Recovery through general rate case • Energy efficiency cost recovery surcharges • System benefits charge
Energy efficiency will reduce electricity or gas sales and revenues and potentially lead to under-recovery of fixed costs.	• Lost revenue adjustment mechanisms that allow recovery of revenue to cover fixed costs • Decoupling mechanisms that sever the link between sales and margin or fixed-cost revenues • Straight fixed-variable (SFV) rate design (allocate fixed costs to fixed charges)
Supply-side investments generate substantial returns for investor-owned utilities. Typically, energy efficiency investments do not earn a return and are, therefore, less financially attractive.[4]	• Capitalize efficiency program costs and include in rate base • Performance incentives that reward utilities for superior performance in delivering energy efficiency

the Midwest, unbundled (i.e., separated the formerly integrated functions of generation, transmission, and distribution) in anticipation of retail competition. Investor-owned natural gas utilities also have gone through a similar unbundling process, albeit one that has been quite different in its form.[5] Unbundling creates two effects relevant to the issues of energy efficiency cost recovery and incentives.

First, unbundling of industry structure also unbundles the value of demand-side programs, in the sense that none of the entities created by unbundling an integrated company can capture the full value of an energy efficiency investment. An integrated utility can capture the value of an energy efficiency program associated with avoided generation, transmission, and distribution costs. The distribution company produced by unbundling an integrated utility can only directly capture the value associated with avoided distribution. One of the principal arguments for public benefits funds was that they could effectively re-bundle this value.[6]

Second, unbundling changes the financial implications of energy efficiency investment as a function of changing cost-of-service structures. The corporate entity subject to continued traditional cost-of-service regulation following unbundling typically is the distribution or wires company. The actual electricity or natural gas sold to consumers is often purchased by consumers directly from competitive or, more commonly, default service providers. In some states, this is also the distribution company. The distribution company adds a distribution service charge to this commodity cost, often levied per unit of throughput, which represents its cost to move the power or gas over its system to the customer. Often, this charge as levied by electric utilities reflects a higher percentage of fixed costs than had been the case when the utility provided bundled service, simply because the utility no longer incurs the variable costs associated with power production.[7] In the case of the distribution company, the potential impact on utility earnings of a drop in sales volume is more pronounced.[8]

Renewed Focus on Resource Planning

Industry restructuring was accompanied by a steep decline in the popularity and practice of resource planning, which had supported much of the early rise in energy efficiency programming. The last several years have seen a resurgence of interest in resource planning (in both bundled and restructured markets) and renewal of interest in ratepayer-funded energy efficiency as a resource option capable of mitigating some of this market volatility.[9]

The intervening years have reshaped the practice of resource planning into a more sophisticated and, sometimes, multi-state process, focused much more on an acknowledgement of and accommodation to the costs and risks surrounding the acquisition of new resources. Energy efficiency investments increasingly are given proper value for their ability to mitigate a variety of policy and financial risks.

Distinctions With a Difference: Gas v. Electric Utilities and Investor-Owned v. Publicly and Cooperatively Owned Utilities

Throughout this Report, distinctions are made between gas and electric utilities and between those that are investor- and publicly or cooperatively owned. In some cases, these distinctions create very important differences in how barriers might be perceived and in whether particular cost recovery and incentive mechanisms are applicable and appropriate. For example, gas and electric utilities face very different market dynamics and can have different cost structures. Declining gas use per customer across the industry creates greater financial sensitivity to the revenue impacts of energy efficiency programs. Publicly and cooperatively owned utilities operate under different financial and, in most states, regulatory structures than investor-owned companies. And just the fact that publicly and cooperatively owned utilities are owned by their customers creates a different set of expectations and obligations. At the same time, all utilities are sensitive to many of the same financial implications, particularly regarding recovery of direct program costs and lost margins. Wherever possible, the Report highlights specific instances in which these distinctions are particularly important.

Rising Commodity Costs and Flattening Sales

The run-up in natural gas prices over the past several years has made the case for gas utility implementation of energy efficiency programs more compelling as a strategy for helping manage customer energy costs. However, where once these programs were implemented in at least a modestly growing gas market, efficiency programs are now combined with flat or declining use per customer, making recovery of program costs and lost margins a more urgent matter.

Acknowledgement of Climate Risk

There is a growing recognition among state policy-makers and electric utilities that action is required to mitigate the impacts of climate change and/or hedge against the likelihood of costly climate policies. Energy efficiency investments are valued for their ability to reduce carbon emissions at low cost by reducing the use of existing high-carbon emitting sources and the deferral of the need for new fossil capacity. Some of the largest electric utilities in the country are forming their business strategies around the likelihood of action on climate policy, and making energy efficiency pivotal in these strategies. Although the environmental attributes of energy efficiency have long been emphasized in arguing the business case for energy efficiency investment, particularly in the electric industry, today that argument appears largely to be over, and attention is shifting to the practical elements of policies that can support scaled-up investment in efficiency.[10]

As utilities increasingly turn to energy efficiency as a key resource, they will look more closely at the links between efficiency, sales, and financial margins, sharpening the question of whether ratemaking policies that reward increases in sales are sustainable. Perhaps less obvious, as policies are implemented to reduce carbon emissions, they likely will create new pathways for capturing the financial value of efficiency that, in turn, will require policy-makers to consider whether current approaches to cost recovery and incentives are aligned with these broader policies.

Advancing Technology

The technology and therefore, the practice of energy efficiency, appear on the edge of significant transformation, particularly in the electric utility industry. The formerly bright line between energy efficiency and demand response[11] is blurring with the growing adoption of advanced metering technologies, innovative pricing regimes, and smart appliances.[12] Emerging technologies enable utilities to more precisely target valuable load reductions, and offer consumers prices that more closely represent the time-varying costs to provide energy. Ultimately, when consumers can receive and act on time- and location-specific energy prices, this will affect the types of energy efficiency measures possible and needed, and efficiency program design and funding will change accordingly. With respect to the immediate issues of cost recovery and incentives, the incorporation of increasing amounts of demand response in utility resource portfolios can change the financial implications of these portfolios, as programs targeted at peak demand reduction as opposed to energy consumption reduction can have a substantially different impact on the recovery of fixed costs.[13]

1.1.2 Current Status

The answer to *"what has changed?"* then, is that the rationale for investment in efficiency has been re-thought, refocused, and strengthened, with ratepayer funding rising to levels eclipsing those of the late 1980s/early 1990s. And as funding rises, the need to address and resolve the issues surrounding energy efficiency program cost recovery and performance incentives take on greater importance and urgency. At the same time, many of the utilities being asked to make this investment are structured differently today than two decades ago during the last efficiency investment boom, so today's efficiency initiatives will have different financial impacts on the utility. Table 1-2 presents a best estimate of the current status of energy efficiency cost recovery and utility performance incentive activity across the country. Where a cell reads "Yes" without reference to gas or electric, the policy applies to both gas and electric utilities.

Table 1-2 reveals that many states have implemented policies that support cost recovery and/or performance incentives to some extent. Even those states that are not shown as having a specific program cost recovery policy

Table 1-2. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Alabama	Yes					
Alaska						
Arizona	Yes (electric)	Yes (electric)		Pending (gas)		Yes (electric)
Arkansas				Yes (gas)		
California	Yes	Yes		Yes		Yes
Colorado	Yes		Yes	Pending		Yes
Connecticut		Yes (electric)			Yes	Yes
Delaware	Yes			Pending		
District of Columbia	Yes			Pending (electric)		
Florida			Yes (electric)			
Georgia	Yes					Yes (electric)
Hawaii				Pending (electric)		Yes
Idaho	Yes (electric)			Yes (electric)		
Illinois	Yes (electric)					
Indiana	Yes			Yes (gas)	Yes	Yes
Iowa	Yes		Yes			
Kansas						Yes
Kentucky			Yes	Pending (gas)	Yes	Yes
Louisiana						
Maine		Yes (electric)				
Maryland				Yes (gas) Pending (electric)		
Massachusetts		Yes (electric)		Pending (electric)	Yes	Yes (electric)
Michigan				Pending (gas)		
Minnesota	Yes			Yes		Yes
Mississippi	Yes					

Source: Kushler et al., 2006. (Current as of September 2007.) Please see Appendix C for specific state citations.

Table 1-2. The Status of Energy Efficiency Cost Recovery and Incentive Mechanisms for Investor-Owned Utilities (continued)

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism	
Missouri				Yes (gas)		
Montana	Yes (gas)	Yes (electric)				Yes
Nebraska						
Nevada	Yes (electric)			Yes (gas)		Yes (electric)
New Hampshire		Yes (electric)		Pending (electric)		Yes (electric)
New Jersey		Yes		Yes (gas) Pending (electric)		
New Mexico	Yes			Pending (gas)		
New York		Yes (electric)		Yes		
North Carolina				Yes (gas)		
North Dakota						
Ohio			Yes (electric)	Yes (gas)	Yes (electric)	Yes (electric)
Oklahoma						
Oregon		Yes		Yes (gas)		
Pennsylvania	Yes					
Rhode Island		Yes (electric)		Yes		Yes
South Carolina						Yes
South Dakota						
Tennessee						
Texas	Yes					
Utah	Yes (electric)		Yes (electric)	Yes (gas)		
Vermont		Yes (electric)			Yes	Yes
Virginia				Pending (gas)		
Washington	Yes (electric)		Yes (electric)	Yes (gas)		
West Virginia						
Wisconsin	Yes (electric)	Yes (electric)		Pending (electric)		
Wyoming						

Source: Kushler et al., 2006. (Current as of September 2007.) Please see Appendix C for specific state citations.

do allow recovery of approved program costs through rate cases. The table also shows that there is a substantial amount of activity surrounding gas revenue decoupling. However, despite the significant level of activity around the country, relatively few states have implemented comprehensive policies that address program cost recovery, recovery of lost margins, and performance incentives. The challenge to policy-makers is whether the level of investment envisioned can be achieved without broader action to implement such comprehensive policies.

1.2 Aligning Utility Incentives with Investment in Energy Efficiency Report

This report on Aligning Utility Incentives with Investment in Energy Efficiency describes the financial effects on a utility of its spending on energy efficiency programs; how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency; and how adoption of various policy mechanisms can reduce or eliminate these barriers. This Report also provides a number of examples of such mechanisms drawn from the experience of a number of utilities and states.

The Report was prepared in response to a need identified by the Action Plan Leadership Group (see Appendix A for a list of group members) for additional practical information on mechanisms for reducing these barriers to support the Action Plan recommendations to "provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective" and "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Key options to consider under this recommendation include committing to a consistent way to recover costs in a timely manner, addressing the typical utility throughput incentive, and providing utility incentives for the successful management of energy efficiency programs.

There are a number of possible regulatory mechanisms for addressing both options, as well as for ensuring recovery of prudently incurred energy efficiency program costs. Determining which mechanism will work best for any given jurisdiction is a process that takes into account the type and financial structure of the utilities in that jurisdiction, existing statutory and regulatory authority, and the size of the energy efficiency investment. The net impact of an energy efficiency cost recovery and performance incentives policy will be affected by a wide variety of other factors, including rate design and resource procurement strategies, as well as broader considerations such as the rate of demand growth and environmental and resource policies.

Specifically, the Report provides a description of three financial effects that energy efficiency spending can have on a utility:

- Failure to recover program costs in a timely way has a direct impact on utility earnings.
- Reductions in sales due to energy efficiency can reduce utility financial margins.
- As a substitute for new supply-side resources, energy efficiency reduces the earnings that a utility would otherwise earn on the supply resource.

This Report examines how these effects create disincentives to utility investment in energy efficiency and the policy mechanisms that have been developed to address these disincentives. In addition, this Report examines the often complex policy environment in which these effects are addressed, emphasizing the need for clear policy objectives and for an approach that explicitly links together the impacts of policies to address utility financial disincentives. Two emerging models for addressing financial disincentives are described, and the Report concludes with a discussion of key lessons for states interested in developing policies to align financial incentives with utility energy efficiency investment.

The subject of financial disincentives and possible remedies has been debated for over two decades, and there remain several unresolved and contentious issues. This Report does

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not attempt to resolve these issues. Rather, by providing discussion of the financial effects of utility efficiency investment, and of the possible policy options for addressing these effects, this Report is intended to deepen the understanding of these issues. In addition, this Report is intended to provide specific examples of regulatory mechanisms for addressing financial effects for those readers exploring options for reducing financial disincentives to sustained utility investment in energy efficiency.

This Report was prepared using an extensive review of the existing literature on energy efficiency program cost recovery, lost margin recovery, and utility performance incentives—a literature that reaches back over 20 years. In addition, this Report uses a broad review of state statutes and administrative rules related to utility energy efficiency program cost recovery. Key documents for the reader interested in additional information include:

- *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives*, Martin Kushler, Dan York, and Patti Witte, American Council for an Energy Efficient Economy, Report Number U061, October 2006.
- *Decoupling for Electric and Gas Utilities: Frequently Asked Questions (FAQ)*, September 2007, available at <http://www.naruc.org>.
- A variety of documents and presentations developed by RAP, available online at <http://www.raponline.org>.
- Ken Costello, *Revenue Decoupling for Natural Gas Utilities—Briefing Paper*, National Regulatory Research Institute, April 2006.
- American Gas Association, *Natural Gas Rate Round-Up, Update on Decoupling Mechanisms—April 2007*.
- DOE, *State and Regional Policies That Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities: A Report to the United States Congress Pursuant to Section 139 of the Energy Policy Act of 2005*, March 2007.
- *Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Counci*l, January 2007.

1.2.1 How to Use This Report

This Report focuses on the issues associated with financial implications of utility-administered programs. For the most part, these issues are the same whether the funding flows from a system benefits charge or is authorized by regulatory action, with the exception that a system benefits charge effectively resolves issues associated with program cost recovery. In addition, the issues related to the effect of energy efficiency on utility financial margins apply whether the efficiency is produced by a utility-administered program or through building codes, appliance standards, or other initiatives aimed at reducing energy use. This Report is intended to help the reader answer the following questions:

- How are utilities affected financially by their investments in energy efficiency?
- What types of policy mechanisms can be used to address the various financial effects of energy efficiency investment?
- What are the pros and cons of these mechanisms?
- What states have employed which types of mechanisms and how have they been structured?
- What are the key differences related to financial impacts between publicly and investor-owned utilities and between electric and gas utilities?
- What new models for addressing these financial effects are emerging?
- What are the important steps to take in attempting to address financial barriers to utility investment in energy efficiency?

This Report is intended for utilities, regulators and regulatory staff, consumer representatives, and energy efficiency advocates with an interest in addressing these financial barriers.

1.2.2 Structure of the Report

Chapter 2 of the Report outlines the basic financial effects associated with utility energy efficiency investment, reviews the key related policy issues, and provides a case study of how a comprehensive approach to addressing financial disincentives to utility energy efficiency investment can have an impact on utility corporate culture. Chapter 3 outlines a range of possible objectives that policy-makers should consider in designing policies to address financial incentives.

Chapters 4, 5, and 6 provide examples of specific program cost recovery, lost margin recovery, and utility performance incentive mechanisms, as well as a review of possible pros and cons. Chapter 7 provides an overview of two emerging cost recovery and performance incentive models, and the Report concludes with a discussion of important lessons for developing a policy to eliminate financial disincentives to utility investment in energy efficiency.

1.2.3 Development of the Report

The Report on Aligning Utility Incentives with Investment in Energy Efficiency is a product of the Year Two Work Plan for the National Action Plan for Energy Efficiency. In addition to direction and comment by the Action Plan Leadership Group, this Guide was prepared with highly valuable input of an Advisory Group. Val Jensen of ICF International served as project manager and primary author of the Report with assistance from Basak Uluca, under contract to the U.S. Environmental Protection Agency.

The Advisory Group members are:

- Lynn Anderson, Idaho Public Service Commission
- Jeff Burks, PNM Resources
- Sheryl Carter, Natural Resources Defense Council
- Dan Cleverdon, DC Public Service Commission
- Roger Duncan, Austin Energy
- Jim Gallagher, New York State Public Service Commission
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- Leonard Haynes, Southern Company
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- Don Low, Kansas Corporation Commission
- Mark McGahey, Tristate Generation and Transmission Association, Inc.
- Barrie McKay, Questar Gas Company
- Roland Risser, Pacific Gas & Electric
- Gene Rodrigues, Southern California Edison
- Michael Shore, Environmental Defense
- Raiford Smith, Duke Energy
- Henry Yoshimura, ISO New England Inc.

1.3 Notes

1. See the *National Action Plan for Energy Efficiency* (2006), available at <www.epa.gov/cleanenergy/actionplan/report.htm>.

2. See <www.epa.gov/actionplan>.

3. "Procurement funds" are monies that are approved by the California Public Utilities Commission for procurement of new resources as part of what is essentially an integrated resource planning process in California.

4. Publicly and cooperatively owned utilities operate under different financial structures than investor-owned utilities and do not face the same issue of earnings comparability, as they do not pay returns to equity holders.

5. Unbundling in the gas industry took a much different form than it did in the electric industry. Gas utilities were never integrated, in the sense that they were responsible for production, transmission, and distribution. Gas utilities always have principally served the distribution function. However, prior to the early 1980s, most gas utilities were responsible for contracting for gas to meet residential, commercial, and industrial demand. Gas industry restructuring led to larger customers being given the ability to purchase gas and transportation service directly, as well as to an end to the typical long-term bundled supply/transportation contracting that gas utilities formerly had engaged in.

6. Some wholesale markets are developing mechanisms to account for the value of demand-side programs. For example, ISO-New England's Forward Capacity Auction allows providers of demand resources to bid demand reductions into the auction.

7. Although natural gas utilities have never had the capital-intensive financial structure common to integrated electric utilities, they historically have tended to be more vulnerable financially to declines in sales because a much greater fraction of the cost of gas service has been associated with the cost of the gas commodity. Prior to gas industry restructuring this problem was even more acute for those utilities procuring gas under contracts with take-or-pay or fixed-charge clauses.

8. According to the Regulatory Assistance Project, the loss of sales due to successful implementation of energy efficiency will lower utility profitability, and the effect may be quite powerful under traditional rate design. "For example, a 5% decrease in sales can lead to a 25% decrease in net profit for an integrated utility. For a stand-alone distribution utility, the loss to net profit is even greater—about double the impact." See Harrington, C., C. Murray, and L. Baldwin (2007). *Energy Efficiency Policy Toolkit*. Regulatory Assistance Project. p. 21. <www.raponline.org>

9. A number of studies have examined the ability of energy efficiency and particularly, demand response programs, to reduce power prices by cutting demand during high-price periods. Because the marginal costs of power typically exceed average costs during these periods, efficiency programs targeted at high demand periods often will yield benefits for all ratepayers, even non-participants. See, for example, *Direct Testimony of Bernard Neenan on Behalf of the Citizens Utility Board and the City Of Chicago*, Cub-City Exhibit 3.0 October 30, 2006, ICC Docket No. 06-0617, State Of Illinois, Illinois Commerce Commission.

10. See, for example: "Greenhouse Gauntlet," 2007 CEO Forum, *Public Utilities Fortnightly*, June 2007. Pacific Gas and Electric (2007). *Global Climate Change, Risks, Challenges, Opportunities and a Call to Action*. </www.pge.com/includes/docs/pdfs/about_us/environment/features/global_climate_06.pdf>

11. Energy efficiency traditionally has been defined as an overall reduction in energy use due to use of more efficiency equipment and practices, while load management, as a subset of demand response has been defined as reductions or shifts in demand with minor declines and sometimes increases in energy use.

12. There remain important distinctions between dispatchable demand response and energy efficiency, including the ability to participate in wholesale markets.

13. For example, a demand-response program that reduces coincident peak demand but has little impact on sales could lead to a financial benefit for a utility, as its costs might decrease by more than its revenues if the cost of delivering power at the peak period exceeds the price for that power.

2: The Financial and Policy Context for Utility Investment in Energy Efficiency

This chapter outlines the potential financial effects a utility may face when investing in energy efficiency and reviews key related policy issues. In addition, it provides a case study of how a comprehensive approach to addressing financial disincentives to utility energy efficiency investment can have an impact on utility corporate culture and explores the issue of regulatory risk.

2.1 Overview

Investment in energy efficiency programs has three financial effects that map generally to specific types of costs incurred by utilities.

- Failure to recover program costs in a timely way has a direct impact on utility earnings.
- Reductions in sales due to energy efficiency can reduce utility financial margins.
- As a substitute for new supply-side resources, energy efficiency reduces the earnings that a utility would otherwise earn on the supply resource.

How these effects are addressed creates the incentives and disincentives for utilities to pursue investment in energy efficiency. Ultimately, it is the combined effect on utility margins of policies to address these impacts that will determine how well utility financial interests align with investment in energy efficiency.

These effects are artifacts of utility regulatory policy and the general practice of electricity and natural gas rate-setting. Individual state regulatory policy and practice will influence how these effects are addressed in any given jurisdiction. Even where broad consensus exists on the need to align utility and customer interests in the promotion of energy efficiency, the policy and institutional context surrounding each utility dictates the specific nature of incentives and disincentives "on the street." The purpose of this chapter is to briefly review some of the important policy considerations that will affect how the financial implications introduced above are treated.

Two broad distinctions are important when considering policy context. The first is between investor-owned and publicly and cooperatively owned utilities. Every state regulates investor-owned utilities.[1] Most states do not regulate publicly or cooperatively owned utilities except in narrow circumstances. Instead, these entities typically are regulated by local governing boards in the case of municipal utilities, or are governed by boards representing cooperative members. Public and cooperative utilities face many of the same financial implications of energy efficiency investment. They set prices in much the same way as investor-owned utilities, and have fixed cost coverage obligations just as investor-owned utilities do. Because these utilities are owned by their customers, it is commonly accepted that customer and utility interests are more easily aligned. However, because municipal utilities often fund city services through transfers of net operating margins into other city funds, there can be pressure to maintain sales and revenues despite policies supportive of energy efficiency.

The second distinction is between electric and natural gas utilities. This distinction is less between forms of regulation and more between the nature of the gas and electric utility businesses. Natural gas utilities historically have operated as distributors. Although many gas utilities continue to purchase gas on behalf of customers, the costs of these purchases are simply passed through to customers without mark-up. Many electric utilities, by contrast, build and operate generating facilities.

Thus, the capital structures of the two types of utilities have differed significantly.[2] Electric utilities, while more capital intensive in the aggregate, historically have had higher variable costs of operation relative to the total cost of service than gas utilities. In other words, while electric utilities required more capital, fixed capital costs represented a larger fraction of the jurisdictional revenue requirement for gas utilities. This has made gas utilities more sensitive to unexpected sales fluctuations and fostered greater interest in various forms of lost margin recovery.

Much of the discussion of mechanisms for aligning utility and customer interests related to energy efficiency investment assumes the utility is an investor-owned electric utility. However, some issues and their appropriate resolution will differ for publicly and cooperatively owned utilities and for natural gas utilities. These differences will be highlighted where most significant.

This chapter reviews each of the three financial effects of utility energy efficiency spending and then briefly examines some of the policy issues that each raises. More detailed examples of policy mechanisms for addressing each effect are provided in following chapters.

2.2 Program Cost Recovery

The first effect is associated with energy efficiency program cost recovery—recovery of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants. Reasonable opportunity for program cost recovery is a necessary condition for utility program spending. Failure to recover these costs produces a direct dollar-for-dollar reduction in utility earnings, and discourages further investment. If, for whatever reason, a utility is unable to recover $500,000 in costs associated with an energy efficiency program, it will see a $500,000 drop in its net margin.

Policies directing utilities to undertake energy efficiency programs in most cases authorize utilities to seek recovery of program costs, even though actual recovery of all costs is never guaranteed.[3] Clarity with respect to the cost recovery process is critical, as broad uncertainty regarding the timing and threshold burden of proof can itself constitute almost as much a disincentive to utility investment as actual refusal to allow recovery of program costs.[4] A reasonable and reliable system of program cost recovery, therefore, is a necessary first element of a policy to eliminate financial disincentives to utility investment in energy efficiency.

Policy-makers have a wide variety of tools available to them to address cost recovery. These tools can have very different financial implications depending on the specific context. More important, history has shown that recovery is not, in fact, a given. Chapter 5 provides a more complete treatment of program cost recovery mechanisms. However, with respect to the broader policy context, several points are important to note here. All are related to risk.

2.2.1 Prudence

State regulatory commissions, as well as the governing boards of publicly and cooperatively owned utilities, have fundamental obligations to ensure that the costs passed along to ratepayers are just and reasonable and were prudently incurred. Sometimes commissions have found these costs to be appropriately born by shareholders (such as "image advertising") rather than ratepayers. Other times, costs are disallowed because they are considered "unreasonable" for the good or service procured or delivered. Finally, regulators and boards might determine that a certain activity would not have been undertaken by prudent managers and thus costs associated with the activity should not be recoverable from ratepayers.

While within the scope of regulatory authority,[5] such disallowances can create some uncertainty and risk for utilities if the rules governing prudence and reasonableness are not clear.[6] Regulated industries traditionally have been viewed as risk averse, in part because with their returns regulated, risk and reward are not symmetrical. Utilities that have been faced with significant disallowances tend to be particularly averse to incurring any cost that is not pre-approved or for which there is a risk that a particular expense will be disallowed.

Program cost recovery requires a negotiation between regulators and utilities to create more certainty regarding prudence and reasonableness and therefore, to assure utilities that energy efficiency costs will be recoverable. Many states provide this balance by requiring utilities to submit energy efficiency portfolio plans and budgets for review and sometimes approval.[7] The utility receives assurance that its proposed expenditures are *decisionally prudent,* and regulators are assured that proposed expenditures satisfy policy objectives. Such pre-approval processes do not preclude regulatory review of actual expenditures or findings that actual program implementation was imprudently managed.

2.2.2 The Timing of Cost Recovery

Cost recovery timing is important for two reasons:

1. If there is a significant lag between a utility's expenditure on energy efficiency programs and recovery of those costs, the utility incurs a carrying cost—it must finance the cash flow used to support the program expenditure. Even if a utility has sufficient cash flow to support program funding, these funds could have been applied to other projects were it not for the requirement to implement the program.

2. The length of the time lag directly affects a utility's perception of cost recovery risk. The composition of regulatory commissions and boards changes frequently and while commissions may respect the decisions of their predecessors, they are not bound to them. Therefore, a change in commissions can lead to changes in or reversals of policy. More important, the longer the time lag, the greater the likelihood that unexpected events could occur that affect a utility's cash flow.

The timing issues can be addressed in several ways. The two most prevalent approaches are to allow a utility to book program costs in a deferral account with an appropriate carrying charge applied, or to establish a tariff rider or surcharge that the utility can adjust periodically to reflect changes in program costs. Neither approach precludes regulators from reviewing actual costs to determine reasonableness and making appropriate adjustments. However, the deferral approach can create what is known as a regulatory asset, which can rapidly grow and, when it is added to the utility's cost of service, cause a jump in rates depending on how the asset is treated.[8]

2.3 Lost Margin Recovery

The objective of an energy efficiency program is to cost-effectively reduce consumption of electricity or natural gas. However, reducing consumption also reduces utility revenues and, under traditional rate designs that recover fixed costs through volumetric charges, lower revenues often lead to under-recovery of a utility's fixed costs. This, in turn, can lead to lower net operating margins and profits and what is termed the *"lost margin"* effect. This same effect can create an incentive in certain cases for utilities to try to increase sales and thus, revenues, between rate cases—this is known as the *throughput incentive.* Because fixed costs (including financial margins) are recovered through volumetric charges, an increase in sales can yield increased earnings, as long as the costs associated with the increased sales are not climbing as fast.

Treatment of lost margin recovery, either in a limited fashion or through some form of what is known as *"decoupling,"* raises basic issues of not only what the regulatory obligation is with regard to utility earnings, but also of the regulators' role in determining the utility's business model. Few energy efficiency policy issues have produced as much debate as the issue of the impact of energy efficiency programs on utility margins (Costello, 2006; Eto et al., 1994; National Action Plan for Energy Efficiency, 2006b; Sedano, 2006).

2.3.1 Defining Lost Margins

The lost margin effect is a direct result of the way that electricity and natural gas prices are set under traditional regulation. And while the issue might be more immediate for investor-owned utilities where profits are at stake, the root financial issues are the same whether the utility is investor-, publicly, or cooperatively owned.

Defining Terms

A variety of terms are used to describe the financial effect of a reduction in utility sales caused by energy efficiency. All of these relate to the practice of traditional ratemaking, wherein some portion of a utility's fixed costs are recovered through a volumetric charge. Because these costs are fixed, higher-than-expected sales will lead to higher-than-expected revenue and possible over-recovery of fixed costs. Lower-than-expected sales will lead to under-recovery of these costs. The terminology used to describe the phenomenon and its impacts can be confusing, as a variety of different terms are used to describe the same effect. Key terms include:

- **Throughput**—utility sales.
- **Throughput incentive**—the incentive to maximize sales under volumetric rate design.
- **Throughput disincentive**—the disincentive to encourage anything that reduces sales under traditional volumetric rate design.
- **Fixed-cost recovery**—the recovery of sufficient revenues to cover a utility's fixed costs.
- **Lost revenue**—the reduction in revenue that occurs when energy efficiency programs cause a drop in sales below the level used to set the electricity or gas price. There generally also is a reduction in cost as sales decline, although this reduction often is less than revenue loss.
- **Lost margin**—the reduction in revenue to cover fixed costs, including earnings or profits in the case of investor-owned utilities. Similar to lost revenue, but concerned only with fixed-cost recovery, or with the opportunity costs of lost margins that would have been added to net income or created a cash buffer in excess of that reflected in the last rate case. The amount of margin that might be lost is a function of both the change in revenue and the any change in costs resulting from the change in sales.

The National Action Plan for Energy Efficiency used *throughput incentive* to describe this effect. Where possible, this Report will also use that phrase. It will also describe the effect using the phrases *under-recovery of margin revenue* or *lost margins,* for the most part to describe issues related to the effect of energy efficiency on recovery of fixed costs.

Traditional cost-of-service ratemaking is based on the same simple arithmetic used in Table 2-1.[9]

average price = revenue requirement/estimated sales[10]

revenue requirement = variable costs + depreciation + other fixed costs + (capital costs × rate of return)

revenue = actual sales × average price

Capital costs are equal to the original cost of plant and equipment used in the generation, transmission, and distribution of energy, minus accumulated depreciation.

The rate of return, in the case of an investor-owned utility, is a weighted blend of the interest cost on the debt used to finance the plant and equipment and an ROE that represents the return to shareholders. The dollar value of this ROE generally represents allowed profit or "margin." Publicly and cooperatively owned utilities do not earn profit per se, and so the rate of return for these enterprises is the cost of debt.[11] The sum of depreciation, other fixed costs (e.g., fixed O&M, property taxes, labor), and the dollar return on invested capital represents a utility's total fixed costs.

If actual sales fall below the level estimated when rates are set, the utility will not collect revenue sufficient to match its authorized revenue requirement. The portion

Table 2-1. The Arithmetic of Rate-Setting

	Baseline (rate setting proceeding)	Case 1 (2% reduction in sales)	Case 2 (2% increase in sales)
1. Variable costs	$1,000,000	$980,000	$1,020,000
2. Depreciation + other fixed costs	$500,000	$500,000	$500,000
3. Capital cost	$5,000,000	$5,000,000	$5,000,000
4. Debt	$3,000,000	$3,000,000	$3,000,000
5. Interest (@10%)	$300,000	$300,000	$300,000
6. Equity	$2,000,000	$2,000,000	$2,000,000
7. Rate of return on equity (ROE@ 10%)	10%	10%	10%
8. Authorized earnings	$200,000	$200,000	$200,000
9. Revenue requirement (1+2+5+8)	$2,000,000	$1,980,000	$2,020,000
10. Sales (kWh)	20,000,000	19,600,000	20,400,000
11. Average price (9÷10)	$0.10	$0.101	$0.99
12. Earned revenue (11×10)	$2,000,000	$1,960,000	$2,040,000
13. Revenue difference (12–9)	0	-$40,000	+$40,000
14. % of authorized earnings (13÷8)	0	-20%	+20%

Note: Sample values used to illustrate the arithmetic of rate-setting.

of the revenue requirement most exposed is a utility's margin. For legal and financial reasons, a utility will use available revenues to cover the costs of interest, depreciation, property taxes, and so forth, with any remaining revenues going to this margin, representing profit for an investor-owned utility.[12,13]

If sales rise above the levels estimated in a rate-setting process, a utility will collect more revenue than required to meet its revenue requirement, and the excess above any increased costs will go to higher earnings.[14] Table 2-1 provides an example based on an investor-owned utility, and Chapter 4 of the Action Plan—the Business Case for Energy Efficiency—provides a very clear illustration of this impact under a variety of scenarios. The results illustrated are sensitive to the relative proportion of fixed and variable costs in a utility's cost of service. The higher the proportion of the variable costs, the lower the impact of a drop in sales. A gas utility's cost-of-service typically will have a higher proportion of fixed costs than an electric utility's and, therefore, the gas utility can be more financially sensitive to changes in sales relative to a test year level.[15]

This example only examines the impact on earnings due to a sales-produced change in revenue. Margins obviously also are affected by costs, and while many costs are considered fixed in the sense that they do not vary as a function of sales, they are under the control of utilities. Therefore, increases in sales and revenue above a test year level do not necessarily translate into higher margins, and the impact of a reduction in sales on margins depends on how a utility manages its costs.

Although the revenue difference appears small, it can be significant due to the effects on financial margins. The Case 1 revenue deficit of $40,000 represents 20 percent of the allowed ROE. In other words, a 2 percent drop in sales below the level assumed in the rate case translates into a 20 percent drop in earnings or margin, all else being equal. Similarly, sales that are 2 percent higher than assumed yield a 20 percent increase in earnings above authorized levels.

The magnitude of the impact is, in this example, directly related to the efficacy of the efficiency program. Many other factors can have a similar impact on utility revenues—for instance, sales can vary greatly from the rate case forecast assumptions due to weather or economic conditions in the utility's service territory. But unlike the weather or the economy, energy efficiency is the most important factor affecting sales that lies within the utility's control or influence, and successful energy efficiency programs can reduce sales enough to create a disincentive to engage in such programs.

In Case 2, actual sales exceed estimated levels. Once rates are set, a utility may have a financial incentive to encourage sales in excess of the level anticipated during the rate-setting process, since additional units of energy sold compensate for any unanticipated increased costs, and may improve earnings.[16]

Chapter 5 explores mechanisms that can be used to address both cases. Generally, two approaches have been used. First, several states have implemented what are termed lost revenue adjustment mechanisms (LRAMs) that attempt to estimate the amount of fixed-cost or margin revenue that is "lost" as a result of reduced sales. The estimated lost revenue is then recovered through an adjustment to rates. The second approach is known generically as "decoupling." A decoupling mechanism weakens or eliminates the relationship between sales and revenue (or more narrowly, the revenue collected to cover fixed costs) by allowing a utility to adjust rates to recover authorized revenues independent of the level of sales. Decoupling actually can take many forms and include a variety of adjustments.

LRAM and decoupling not only represent alternative approaches to addressing the lost margins effect, but they also reflect two different policy questions related to the relationship between utility sales and profits.

Provide compensation for lost margins?

Should a utility be compensated for the under-recovery of allowed margins when energy efficiency programs—or events outside of the control of the utility, such as weather or a drop in economic activity—reduce sales below the level on which current rates are based? The financial implication—with all else being held equal—is easy to illustrate as shown in Table 4-1. In practice, however, determining what is lost as a direct result of the implementation of energy efficiency programs is not so simple. The determination of whether this loss should stand alone or be treated in context of all other potential impacts on margins also can be challenging. For example, during periods between rate cases, revenues and costs are affected by a wide variety of factors, some within management control and some not. The impacts of a loss of revenue due to an energy efficiency program could be offset by revenue growth from customer growth or by reductions in costs. On the other hand, the addition of new customers imposes costs which, depending on rate structure, can exceed incremental revenues.

Change the basic relationship between sales and profit?

Should lost margins be addressed as a stand-alone matter of cost recovery, or should they be considered within a policy framework that changes the relationship between sales, revenues, and margins—in other words by decoupling revenues from sales? Decoupling not only addresses lost margins due to efficiency program implementation. It also removes the incentive a utility might otherwise have to increase throughput, and can reduce resistance to policies like efficient building codes, appliance standards, and aggressive energy efficiency awareness campaigns that would reduce throughput.

Decoupling also can have a significant impact on both utility and customer risk. For example, by smoothing earnings over time, decoupling reduces utility financial risk, which some have argued can lead to reductions in the utility's cost-of-capital. (For a discussion of this issue, see Hansen, 2007, and Delaware PSC, 2007.) Depending on precisely how the decoupling mechanism is structured, it can shift some risks associated with sales unpredictability (e.g., weather, economic growth) to consumers.[17] This is a design decision within the control of policy-makers, and not an inherent characteristic of decoupling. The issue of the effect of decoupling on risk and therefore, on the cost-of-capital, likely will receive greater attention as decoupling increasingly is pursued. The existing literature and current experience is inconclusive, and the policy discussion would benefit from a more complete examination of the issue than is possible in this Report.

Ultimately, the policy choice must be made based on practical considerations and a reasonable balancing of interests and risks. Most observers would agree that significant and sustained investment in energy efficiency by utilities, beyond that required by statute or order, will not occur absent implementation of some type of lost margin recovery mechanism. More important, a policy that hopes to encourage aggressive utility investment in energy efficiency most likely will not fundamentally change utility behavior as long as utility margins are directly tied to the level of sales. The increasing number of utility commissions investigating decoupling is clear evidence that this question has moved front and center in development of energy efficiency investment policies across the country.

2.4 Performance Incentives

The first two financial impacts described above pertain to obvious disincentives for utilities to engage in energy efficiency program investment. The third effect concerns incentives for utilities to undertake such investment. Full recovery of program costs and collection of allowed revenue eliminates potential financial penalties associated with funding energy efficiency programs. However, simply eliminating financial penalties will not fundamentally change the utility business model, because that model is premised on the earnings produced by supply-side investment. In fact, the earnings inequality between demand- and supply-side investment even where program costs and lost margins are addressed can create a significant barrier to aggressive investment in energy efficiency. An enterprise organized to focus on and profit by investment in supply is not easily converted to one that is driven to reduce demand. This is particularly true in the absence of clear financial incentives or fundamental changes in the business environment.[18]

This issue is fundamental to a core regulatory function—balancing a utility's obligation to provide service at the lowest reasonable cost and providing utilities the opportunity to earn reasonable returns. For example, assume that an energy efficiency program can satisfy an incremental resource requirement at half the cost of a supply-side resource, and that in all other financial terms the efficiency program is treated like the supply resource. Cost recovery is assured and lost margins are addressed. In this case, the utility will earn 50 percent of the return it would earn by building the power plant. Consumers as a whole clearly would be better off by paying half as much for the same level of energy service. However, the utility's earnings expectations are now changed, with a potential impact on its stock price, and total returns to shareholders could decline. There could be additional benefits, to the extent that investors perceive the utility less vulnerable to fuel price or climate risk, but under the conventional approach to valuing businesses, the utility would be less attractive. This is an extreme example, and it is more likely that this trade-off plays out more modestly over a longer period of time. Nevertheless, the prospective loss of earnings from a shift towards greater reliance on demand-side resources is a concern among investor-owned utilities, and it will likely influence some utilities' perspective on aggressive investment in energy efficiency.[19]

The importance of performance incentives is not universally accepted. Some parties will argue that utilities are obligated to pursue energy efficiency if that is the policy of the State. Those taking this view will see performance incentives as requiring customers to pay utilities to do something that should be done anyway. Others have argued that the basic business of a utility is to deliver energy, and that providing financial incentives over-and-above what could be earned by efficient management of the supply business simply raises the cost of service to all customers and distorts management behavior.

Those holding this latter view often prefer that energy efficiency investment be managed by an independent third-party (see, for example, ELCON, 2007). Existing third-party models, such as those in Oregon, Vermont, and Wisconsin, have received generally high marks, but these models carry a variety of implications beyond those related to lost margins and performance incentives. Policy-makers interested in a third party model must balance the potentially beneficial effects for ratepayers with what is typically a lower level of control over the third party, and increased complexity in integrating supply- and demand-side resource policy.

Apart from this threshold issue, regulators face a variety of options for providing incentives to utilities (see Chapter 7), ranging from mechanisms that tie a financial reward to specific performance metrics, including savings, to options that enable a sharing of program benefits, to rewards based on levels of program spending.[20] The latter type of mechanism, while sometimes derided as an incentive to spend, not save, has been applied in some cases simply because it is easier to develop and implement, and it can be combined with pre- and post-implementation reviews to ensure that ratepayer funds are being used effectively.

Providing financial incentives to a utility if it performs well in delivering energy efficiency potentially can change the existing utility business model by making efficiency profitable rather than merely a break-even activity. Today such incentives are the exception rather than the norm. For example, California policy-makers have acknowledged that successfully reorienting utility resource acquisition policy to place energy efficiency first in the resource "loading order" requires that performance incentives be re-instituted (see CPUC, 2006).

2.5 Linking the Mechanisms

Each of the financial effects suggests a different potential policy response, and policy-makers can and have approached the challenge in a variety of ways. It is the net financial effect of a package of cost recovery and incentive policies that matters in devising a policy framework to stimulate greater investment in energy efficiency. A variety of policy combinations can yield roughly the same effect. However, to the extent that mechanisms are developed to address all financial effects, care must be taken to ensure that the interactions among these are understood.

The essential foundation of the policy framework is program cost recovery. While confidence in its ability to recover these direct costs is central to a utility's willingness to invest in energy efficiency, a number of options are available for recovery, some of which also address lost margins and performance incentives. Some states directly provide for lost margin recovery for losses due to efficiency programs through a decoupling or LRAM while others create performance incentive policies that indirectly compensate for some or all lost margins. Minnesota, for example, abandoned its lost margin recovery mechanism in favor of a performance incentive after finding that levels of margin recovery had become so large that their recovery could not be supported by the

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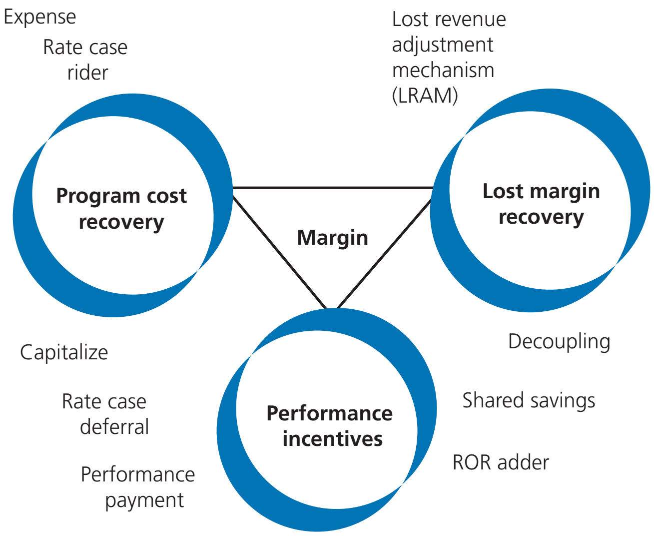
Figure 2-1. Linking Cost Recovery, Recovery of Lost Margins, and Performance Incentives



commission. Although it has been difficult to determine the precise impact of the change in policy, the utilities in Minnesota have indicated that they are generally satisfied given that prudent program cost recovery is guaranteed and significant performance incentives are available.[21,22] Finally, the combination of program cost recovery and a decoupling mechanism could create a positive efficiency investment environment, even absent performance incentives. Depending on its structure, a decoupling mechanism can create more earnings stability, which, all else being equal, can reduce risk.[23]

2.6 "The DNA of the Company:" Examining the Impacts of Effective Mechanisms on the Corporate Culture

A policy that addresses all three financial effects will, in theory, have a powerful impact on utility behavior and, ultimately, corporate culture, turning what for many utilities is a compliance function into a key element of business strategy.[24] Perhaps the clearest example of this is Pacific Gas & Electric.

PG&E has one of the richest histories of investment in energy efficiency of any utility in the country, dating to the late 1970s. A vital part of that history has been California's policy with respect to program cost recovery, treatment of fixed-cost recovery and performance incentives. Decoupling, in the form of electric rate adjustment mechanism (ERAM), was instituted in 1982. ERAM was suspended as the state embarked on its experiment with utility industry restructuring. While that specific mechanism has not been reinstituted, 2001 legislation effectively required reintroduction of decoupling, which each investor-owned utility has pursued, though in slightly different forms. Similarly, utility performance incentives were authorized more than a decade ago, but were suspended in 2002 amidst of a broad rethinking of the administrative structure for energy efficiency investment in the State. A September 2007 decision by the California Public Utilities Commission (CPUC), reinstated utility performance incentives through an innovative risk/reward mechanism offering utilities collectively up to $450 million in incentives over a three-year period. At the same time, this mechanism will impose penalties on utilities for failing to meet performance targets (see Section 7.3 for a more complete description).

The policy framework in California supports very aggressive investment in energy efficiency, placing energy efficiency first in the resource loading order through adoption of the state's Energy Action Plan. The Energy Action Plan also established that utilities should earn a return on energy efficiency investments commensurate with foregone return on supply-side assets. Public proceedings directed by CPUC set three-year goals for each utility, and the payment of performance incentives will be based on meeting these goals.

PG&E's current energy efficiency investment levels are approaching an all-time high, totaling close to $1 billion over the 2006–2008 period. Base funding comes from the state's public goods charge, but a substantial fraction now comes as the result of the State's equivalent of integrated resource planning proceedings. These procurement proceedings, through which the loading order is implemented, will continue to maintain energy efficiency funding at levels in excess of the public goods charge, as the state pursues aggressive savings goals.

A view only to savings targets and spending levels might suggest that a discussion of disincentive to investment and utility corporate culture is irrelevant in PG&E's case. However, support for these aggressive investments appears to be run deep within the California investor-owned utilities, and clearly this policy would struggle were it not for utility support. Even so, has this policy actually shaped utility corporate culture?

Discussions with PG&E management suggest the answer is "yes" (personal communication with Roland Risser, Director of Customer Energy Efficiency, Pacific Gas & Electric Company, May 2, 2007). Although investment levels always have been high in absolute terms, the company's view in the 1980s initially had been that, as long as energy efficiency investment did not hurt financially, the company would not resist that investment. However, the combined effect of ERAM and utility performance incentives turned what had been a compliance function into a vital piece of the company's business, and a defining aspect of corporate culture that has produced the largest internal energy efficiency organization in the country.[25]

The policy and financial turbulence created by the state's attempt at industry restructuring challenged this culture, first as ERAM and performance incentives were halted, and then as the regulatory environment turned sour with the energy crisis. However, a combination of a new policy recommitment to demand-side management (DSM), and the arrival of a new PG&E CEO have combined to reset the context for utility investment in efficiency and strengthen corporate commitment. Decoupling is again in place and CPUC has adopted a new performance incentive structure.

The significant escalation in efficiency funding driven by California's Energy Action Plan, in addition to resource procurement proceedings, required the company to address the role of energy efficiency investment in more fundamental terms internally. The choices made in the procurement proceedings allocated funding to energy efficiency resources—funding that otherwise would have gone to support acquisition of conventional supply. While in most organizations such allocation processes can create fierce competition, the environment within PG&E has significantly reduced potential conflict and even more firmly embedded energy efficiency in the company's clean energy strategy.

The culture shift certainly is the product of a combination of forces, including the arrival of a new CEO with a strong commitment to climate protection; a state policy environment that is intensely focused on clean energy development; an investment community interested in how utilities hedge their climate risks; and the re-emergence of favorable treatment of fixed-cost coverage and performance incentives. It is not clear that progressive cost recovery and incentive policies are solely responsible for this change, but without these policies it is unlikely that efficiency investment would have become a central element of corporate strategy, embedded "in the DNA of the Company" (personal communication with Roland Risser, PG&E).

Would the same cost recovery and incentive structure have the same effect elsewhere? That answer is unclear, though it is unlikely that simply adopting mechanisms similar to what are in place in California would effect overnight change. Corporate culture is formed over extended periods of time and is influenced by the whole of an operating environment and the leadership of the company. Nevertheless, according to senior PG&E staff, the effect of the cost recovery and incentive policies is undeniable—in this case it was the catalyst for the change.

2.7 The Cost of Regulatory Risk

A comprehensive cost recovery and incentive policy can help institutionalize energy efficiency investment within a utility. At the same time, the absence of a comprehensive approach, or the inconsistent and unpredictable application of an approach, can create confusion with respect to regulatory policy and institutionalize resistance to energy efficiency investment. A significant risk that policy-makers could disallow recovery of program costs and/or collection of incentives, even if such investments have been encouraged, imposes a real, though hard-to-quantify cost on utilities. While a significant disallowance can have direct financial implications, a less tangible cost is associated with the institutional friction a disallowance will create. Organizational elements within a utility responsible for energy efficiency initiatives will find it increasingly difficult to secure resources. Programs that are offered will tend to be those that minimize costs rather than maximize savings or cost-effectiveness. Easing this friction will not be as simple as a regulatory message that it will not happen again, and in fact the disallowance could very well have been justified, should have happened, and would happen again.

Regulators clearly cannot give up their authority and responsibility to ensure just and reasonable rates based on prudently incurred costs. And changes in the course of policy are inevitable, making flexibility and adaptability essential. All parties must realize, however, that the consistent application of policy with respect to cost recovery and incentives matters as much if not more than the details of the policies themselves. The wide variety of cost recovery and incentive mechanisms provides opportunities to fashion a similar variety of workable policy approaches. Significant and sustained investment in energy efficiency by utilities very clearly requires a broad and firm consensus on investment goals, strategy, investment levels, measurement, and cost recovery. It is this consensus that provides the necessary support for consistent application of cost recovery and incentives mechanisms.[26]

2.8 Notes

1. However, as they explored industry restructuring, a number of states stripped utility commissions of regulatory authority over generation and, in some cases, transmission to varying degrees.

2. In fact, many gas utilities do make investment in plant and equipment beyond gas distribution pipes—gas peaking and storage facilities, for example.

3. Recovery of costs always is based on demonstration that the costs were prudently incurred.

4. The forward period for which energy efficiency program costs is approved can be quite important to the success of programs. Year-by-year approval requirements complicate program planning, and longer term commitments to the market actors cannot be made. The trend among states is to move toward longer program implementation periods, e.g., three years. Thus, to the extent that program costs are reviewed as part of proposed implementation plans, initial approval for spending is conferred for the three-year period, providing program stability and flexibility.

5. Courts can rule on appeal that regulatory disallowances were not supported by the facts of a case or by governing statute.

6. In fact, some such disallowances have had the effect of clarifying these rules.

7. Another approach to achieving this balance is using stakeholder collaboratives to review, help fashion, and, where appropriate based on this review, endorse certain utility decisions. Where these collaboratives produce stipulations that can be offered to regulators, they provide some additional assurance to regulators that parties who might otherwise challenge the prudence or reasonableness of an action, have reviewed the proposed action and found it acceptable. Though sometimes time-and resource-intensive, such collaboratives have been helpful tools for reducing utility prudence risk related to energy efficiency expenditures.

8. In addition, because such regulatory asset accounts are backed not by hard assets but by a regulatory promise to allow recovery, their use can raise concern in the financial community particularly for utilities with marginal credit ratings.

9. The lost margin issue actually arises as a function of rate designs that intend to recover fixed costs through volumetric (per kilowatt-hour or therm) charges. A rate design that placed all fixed costs of service in a fixed charge per customer (SFV rate) would largely alleviate this problem. However such rates significantly reduce a consumer's incentive to undertake efficiency investments, since energy use reductions would produce much lower customer bill savings relative to a the situation under a rate design that included fixed costs in volumetric charges. In addition, fixed-variable rates are criticized as being regressive (the lower the use, the higher the average cost per unit consumed) and unfair to low-income customers. See Chapter 5, "Rate Design," of the Action Plan for an excellent discussion of this process.

10. This equation is a simplification of the rate-setting process. The actual rates paid per kilowatt-hour or therm often will be higher or lower than the average revenue per unit.

11. Note, however, that publicly owned utilities typically must transfer some fraction of net operating margins to other municipal funds, and cooperatively owned utilities typically pay dividends to the member of the co-op. These payments are the practical equivalent of investor-owned utility earnings. In addition, these utilities typically must meet bond covenants requiring that they earn sufficient revenue to cover a multiple of their interest obligations. Therefore, there can be competing pressures for publicly and cooperatively owned utilities to maintain or increase sales at the same time that they promote energy efficiency programs.

12. Although a utility is not obligated to pay returns to shareholders in the same sense that it is obligated to pay for fuel or to pay the interest associated with debt financing, failure to provide the opportunity to earn adequate returns will lead equity investors to view the utility as a riskier or less desirable investment and will require a higher rate of return if they are to invest in the utility. This will increase the utility's overall cost of service and its rates.

13. Publicly and cooperatively owned utilities do not earn profits per se and thus, have no return on equity. However, they do earn financial margins calculated as the difference between revenues earned and the sum of variable and fixed costs. These margins are important as they fund cooperative member dividends and payments to the general funds of the entities owning the public utilities.

14. The actual impact on margins of a change in sales depends critically on the extent to which fixed costs are allocated to volumetric charges. Actual electricity and natural gas prices usually include both a fixed customer charge and a price per unit of energy consumed. The larger the share of fixed costs included in this price per unit, the more a utility's margin will fluctuate with changes in sales.

15. A gas utility's cost of service does not include the actual commodity cost of gas which is flowed through directly to customers without mark-up.

16. Some states require utilities to participate in a rate case every two or three years. Others hold rate cases only when a utility believes it needs to change its prices in light of changing costs or the regulatory agency believes that a utility is over-earning.

17. Unless properly structured, a decoupling mechanism also can lead to a utility over-earning—collecting more margin revenue than it is authorized to collect.

18. An alternative has been for state utility commissions to require adherence to least-cost planning principles that require the less expensive energy efficiency to be "built," rather than the new supply-side resource. However, this approach does not alter the basic financial landscape described above.

19. The California Public Utilities Commission's recent ruling regarding utility performance rewards explicitly recognized this issue.

20. The actual implementation of an incentive mechanism may address more than financial incentives. For example, The Minnesota Commission considers its financial incentive mechanism as effectively addressing the financial impact of the reduction in revenue due to an energy efficiency program.

21. State EE/RE Technical Forum Call #8, Decoupling and Other Mechanisms to Address Utility Disincentives for Implementing Energy Efficiency, May 19, 2005. <http://www.epa.gov/cleanenergy/stateandlocal/efficiency.htm#decoup>

22. The Minnesota Legislature recently adopted legislation directing the Minnesota Public Service Commission to adopt criteria and standards for decoupling, and to allow one or more utilities to establish pilot decoupling programs. S.F. No. 145, 2nd Engrossment 85th Legislative Session (2007–2008).

23. As noted, some argue that this risk reduction should translate into a corresponding reduction in the cost of capital, although views are mixed regarding the extent to which this reduction can be quantified.

24. For a broader discussion of how cost recovery and incentive mechanisms can affect the business model for utility investment in energy efficiency, see NERA Economic Consulting (2007). *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities. Prepared for Edison Electric Institute.*

25. This infrastructure was significantly scaled back during California's restructuring era.

26. One way to manage the regulatory risk issue is to make the regulatory goals very clear and long-term in nature. Setting energy savings targets—for example, by using an Energy Efficiency Resource Standard—can remove some part of the utility's risk. If the utility meets the targets, and can show that the targets were achieved cost-effectively, prudence and reasonableness are easier to establish, and cost recovery and incentive payments become less of an issue. Otherwise, more issues are under scrutiny: did the utility seek "enough" savings? Did it pursue the "right" technologies and markets? With a high-level, simple, and long-term target, such issues become less germane.

3: Understanding Objectives—Developing Policy Approaches That Fit

This chapter explores a range of possible objectives for policy-makers' consideration when exploring policies to address financial disincentives. It also addresses the broader context in which these objectives are pursued.

3.1 Potential Design Objectives

Each jurisdiction could value the objectives of the energy efficiency investment process and the objectives of cost recovery and incentive policy design differently. Jurisdictional approaches are formed by a variety of statutory constraints, as well as by the ownership and financial structures of the utilities; resource needs; and related local, state, and federal resource and environmental policies. ***The overarching objective in every jurisdiction that considers an energy efficiency investment policy should be to generate and capture substantial net economic benefits***. This broad objective sometimes is expressed as a spending target, but more often as an energy or demand reduction target, either absolute (e.g., 500 MW by 2017) or relative (e.g., meet 10, 50, or 100 percent of incremental load growth or total sales). Increasingly, states are linking this objective to others that promote the use of cost-effective energy efficiency as an environmentally preferred option. The objectives outlined below guide how a cost recovery and incentive policy is crafted to support this overarching objective.

A review of the cost recovery and incentive literature, as well as the actual policies established across the country, reveals a fairly wide set of potential policy objectives. Each one of these is not given equal weight by policy-makers, but most of these are given at least some consideration in virtually every discussion of cost recovery and performance incentives. Many of these objectives apply to broader regulatory issues as well. Here the focus is solely on the objectives as they might apply to design of cost recovery and incentive mechanisms intended to serve the overarching objective stated above; that is whether the treatment of these objectives leads to a policy that effectively incents substantial cost-effective savings. A cost recovery and incentives policy that satisfies each of the design objectives described below, but which does not stimulate utility investment in energy efficiency, would not serve the overarching objective.

3.1.1 Strike an Appropriate Balance of Risk/Reward Between Utilities/Customers

The principal trade-off is between lowering utility risk/enhancing utility returns on the one hand and the magnitude of consumer benefits on the other. Mechanisms that reduce utility risk by, for example, providing timely recovery of lost margins and providing performance incentives, reduce consumer benefit, since consumers will pay for recovery and incentives through rates.[1] However, if the mechanisms are well-designed and implemented, customer benefits will be large enough that sharing some of this benefit as a way to reduce utility risk and strengthen institutional commitment will leave all parties better off than had no investment been made.

3.1.2 Promote Stabilization of Customer Rates and Bills

This objective is common to many regulatory policies and is relevant to energy efficiency cost recovery and incentives policy primarily with respect to recovery of lost margins. The ultimate objective served by a cost recovery and incentives policy implies an overall reduction in the long run costs to serve load, which equate to the total amount paid by customers over time. Therefore, while it is prudent to explore policy designs that, among available options, minimize potential rate volatility, the pursuit of rate stability should be balanced against the broader interest of total customer bill reductions. In fact, there are cases (Questar Gas in Utah, for example) where energy efficiency programs produce benefits for all customers (programs pass the so-called No-Losers test of cost-effectiveness) through reductions in commodity costs (Personal communication with Barry McKay, Questar Gas, July 9, 2007).

Program costs and performance incentives are relatively stable and predictable, or at least subject to caps. Lost margins can grow rapidly, and recovery can have a noticeable impact on customer rates. Decoupling mechanisms can be designed to mitigate this problem through the adoption of annual caps, but there have been isolated cases in which the true-ups have become so large due to factors independent of energy efficiency investment that regulators have balked at allowing full recovery.[2] Therefore, consideration of this objective is important for customers and utilities, as erratic and substantial energy efficiency cost swings can imperil full recovery and increase the risk of efficiency investments for utilities.

3.1.3 Stabilize Utility Revenues

This objective is a companion to stabilization of rates. Aggressive energy efficiency programs will impact utility revenues and full recovery of fixed costs. However, even if cost recovery policy covers program costs, lost margins, and performance incentives, how this recovery takes place can affect the pattern of earnings. Large episodic jumps in earnings (for example, produced by a decision to allow recovery of accrued lost margins in a lump sum), while better than non-recovery, cloud the financial community's ability to discern the true financial performance of the company, and creates the perception of risk that such adjustments might or might not happen again. PG&E views the ability of its decoupling mechanism to smooth earnings as a very important risk mitigation tool (personal communication with Roland Risser, PG&E).

3.1.4 Administrative Simplicity and Managing Regulatory Costs

Simplicity requires that any/all mechanisms be transparent with respect to both calculation of recoverable amounts and overall impact on utility earnings. This, in turn, supports minimizing regulatory costs. Given the workload facing regulatory commissions, adoption of cost recovery and incentive mechanisms that require frequent and complex regulatory review will create a latent barrier to effective implementation of the mechanisms. Every mechanism will impose some incremental cost on all parties, since some regulatory responsibilities are inevitable. The objective, therefore, is to structure mechanisms with several attributes that can establish at least a consistent and more formulaic process.

The mechanism should be supported by prior regulatory review of the proposed efficiency investment plan, and at least general approval of the contours of the plan and budget. In the alternative, policy-makers can establish clear rules prescribing what is considered acceptable/necessary as part of an investment plan, including cost caps. This will reduce the amount of time required for post-implementation review, as the prudence of the investment decision and the reasonableness of costs will have been established.

Use of tariff riders with periodic true-up allows for more clear segregation of investment costs and adjustment for over/under-recovery than simply including costs in a general rate case. However, in some states, the periodic treatment of energy efficiency program costs, fixed cost recovery, and incentives outside of a general rate case could be prohibited as single-issue ratemaking.[3]

Because certain mechanisms require evaluation and verification of program savings as a condition for recovery, very clear specification of the evaluation standards at the front end of the process is important. Millions of dollars are at stake in such evaluations, and failure to prescribe these standards early in the process almost guarantees that evaluation methods will be contested in cost recovery proceedings.

3.2 The Design Context

The need to design mechanisms that match the often unique circumstances of individual jurisdictions is clear, but what are the variables that determine the context for cost recovery and incentive design? Table 3-1 identifies and describes several variables often cited as important influences.

Table 3-1. Cost Recovery and Incentive Design Considerations

Variable	Implication
Related to Industry Structure	
Differences between gas and electric utility policy and operating environments	Wide variety of embedded implications. Gas utility cost structures create greater sensitivity to sales variability and recovery of fixed costs. In addition, as an industry, gas utilities face declining demand per customer.
Differences between investor-, publicly, and cooperatively owned utilities	Significant differences in financing structures. Municipal and cooperative ownership structures might provide greater ratemaking flexibility. Shareholder incentives are not relevant to publicly and cooperatively owned utilities, although management incentives might be.
Differences between bundled and unbundled utilities	Unbundled electric utilities have cost structures with some similarities to gas utilities; may be more susceptible to sales variability and fixed-cost recovery.
Presence of organized wholesale markets	Organized markets may provide an opportunity for utilities to resell "saved" megawatt-hours and megawatts to offset under-recovery of fixed costs.
Related to Regulatory Structure and Process	
Utility cost recovery and ratemaking statutes and rules	Determines permissible types of mechanisms. Prohibitions on single-issue ratemaking could preclude approval of recovery outside of general rate cases. Accounting rules could affect use of balancing and deferred/escrow accounts. Use of deferred accounts creates regulatory assets that are disfavored by Wall Street.
Related legislative mandates such as DSM program funding levels or inclusion of DSM in portfolio standards	Can eliminate decisional prudence issues/reduce utility program cost recovery risk. Does not address fixed-cost recovery or performance incentive issues.

Table 3-1. Cost Recovery and Incentive Design Considerations (continued)

Variable	Implication
Related to Regulatory Structure and Process (continued)	
Frequency of rate cases and the presence of automatic rate adjustment mechanisms	Frequent rate cases reduce the need for specific fixed-cost recovery mechanism, but do not address utility incentives to promote sales growth or disincentives to promote customer energy efficiency. Utility and regulator costs increase with frequency.
Type of test year	Type of test year (historic or future) is relevant mostly in cases in which energy efficiency cost recovery takes place exclusively within a rate case. Test year costs typically must be known, which can pose a problem for energy efficiency programs that are expected to ramp-up significantly. This applies particularly to the initiation or significant ramp-up of energy efficiency programs combined with a historic test year.
Performance-based ratemaking elements	Initiating an energy efficiency investment program within the context of an existing performance-based ratemaking (PBR) structure can be complicated, requiring both adjustments in so-called "Z factors"4 and performance metrics. However, revenue-cap PBR can be consistent with decoupling.
Rate structure	The larger the share of fixed costs allocated to fixed charges, the lower the sensitivity of fixed-cost recovery to sales reductions. Price cap systems pose particular issues, since costs incurred for programs implemented subsequent to the cap but prior to its expiration must be carried as regulatory assets with all of the associated implications for the financial evaluation of the utility and the ultimate change in prices once the cap is lifted.
Regulatory commission/governing board resources	Resource-constrained commissions/governing boards may prefer simpler, self-adjusting mechanisms.
Related to the Operating Environment	
Sales/peak growth and urgency of projected reserve margin shortfalls	Rapid growth may imply growing capacity needs, which will boost avoided costs. Higher avoided costs create a larger potential net benefit for efficiency programs and higher potential utility performance incentive. Growth rate does not affect fixed-cost recovery if the rate has been factored into the calculation of prices.

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Table 3-1. Cost Recovery and Incentive Design Considerations (continued)	
Variable	**Implication**
Related to the Operating Environment (continued)	
Volatility in load growth	Unexpected acceleration or slowing of load growth can have a major impact on fixed-cost recovery, an impact that can vary by type of utility. Higher than expected growth can lessen the impact of energy efficiency on fixed cost recovery, while slower growth exacerbates it. On the other hand, if the cost to add a new customer exceeds the embedded cost, higher than expected growth can adversely impact utility finances.
Utility cost structure	Utilities with higher fixed/variable cost structures are more susceptible to the fixed-cost recovery problem.
Structure of the DSM portfolio	Portfolios more heavily weighted toward electric demand response will result in less significant lost margin recovery issues, thus reducing the need for a specific mechanism to address. Moreover, a portfolio weighted toward demand response typically will not offer the same environmental benefits.

3.3 Notes

1. A related concern raised by skeptics of performance incentives is that by providing an incentive to utilities to deliver successful energy efficiency programs, customers might pay more than they otherwise should or would have to achieve the same result if another party delivered the programs, or if the utilities were simply directed to acquire a certain amount of energy savings. Of course, the counter-argument is that in some cases, the level of savings actually achieved by a utility (savings in excess of a goal, for example) are motivated by the opportunity to earn an incentive. In addition, certain third-party models include the opportunity for the administering entity to earn performance incentives.

2. See the discussion of the Maine decoupling mechanism in the National Action Plan for Energy Efficiency, July 2006, Chapter 2, pages 2–5. The examples of this issue are isolated, emerging in early decoupling programs in the electric utility industry. The negative impacts were exacerbated by accounting treatments that deferred recovery of the revenues in the balancing accounts.

3. Single issue ratemaking allows for a cost change in a single item in a utility's cost of service to flow through to consumer rates. A prohibition on single-issue ratemaking occurs because, among the multitude of utility cost items, there will be increases and decreases, and many states find it inappropriate to base a rate change on the movement of any single cost item in isolation. In some states, a fuel adjustment clause is an exception to this rule, justified because the impacts of changes in fuel costs on the total cost of service is high. States that employ an energy efficiency rider justify this exception as a function of the policy importance of energy efficiency and as an important element in creating a stable energy efficiency funding environment.

4. Z factors are factors affecting the price of service over which the utility has no control. PBR programs typically allow rate cap adjustments to accommodate changes in these factors.

4: Program Cost Recovery

This chapter provides a practical overview of alternative cost recovery mechanisms and presents their pros and cons. Detailed case studies are provided for each mechanism.

4.1 Overview

Administration and implementation of energy efficiency programs by utilities or third-party administrators involves the annual expenditure of several million dollars to several hundred million dollars, depending on the jurisdiction. The most basic requirement for elimination of disincentives to customer-funded energy efficiency is establishing a fair, expeditious process for recovery of these costs, which include participant incentives and implementation, administration, and evaluation costs. Failure to recover such costs directly and negatively affects a utility's cash flow, net operating income, and earnings.

Utilities incur two types of costs in the provision of service. Capital costs are associated with the plant and equipment associated with the production and delivery of energy. Expenses typically are the costs of service that are not directly associated with physical plant or other hard assets.[1] The amount of revenue that a utility must earn over a given period to be financially viable must cover the sum of expenses over that period plus the financial cost associated with the utility's physical assets. In simple terms, a utility revenue requirement is equivalent to the cost of owning and operating a home, including the mortgage payment and ongoing expenses. The costs associated with utility energy efficiency programs must be recovered either as expenses or as capital items.

The predominant approach to recovery of program costs is through some type of periodic rate adjustment established and monitored by state utility regulatory commissions or the governing entities for publicly or cooperatively owned utilities. These regulatory mechanisms can take a variety of forms including recovery as expenses in traditional rate cases, recovery as expenses through surcharges or riders that can be adjusted periodically outside of a formal rate case, or recovery via capitalization and amortization. Variations exist within these broad forms of cost recovery as well, through the use of balancing accounts, escrow accounts, test years, and so forth.

The approach applied in any given jurisdiction will often be the product of a variety of local factors such as the frequency of rate cases, the specific forms of cost accounting allowed in a state, the amount and timing of expenditures, and the types of programs being implemented. States will also differ in how costs are distributed across and recovered from different customer classes. Some states, for example, allow large customers to opt-out of efficiency programs administered by utilities,[2] and some states require that costs be recovered only from the classes of customers directly benefiting from specific programs. These variations preclude a single best approach. However, for those utilities and states considering implementation of energy efficiency programs, the variety of approaches offers a variety of options to consider.

4.2 Expensing of Energy Efficiency Program Costs

Most energy efficiency program costs are recovered through "expensing." In the simplest case, if a utility spends $1.00 to fund an energy efficiency program, that $1.00 is passed directly to customers as part of the utility's cost of service. While in principle, the expensing of energy efficiency program costs is straightforward, utilities and state regulatory commissions have employed a wide variety of specific accounting treatments and actual recovery mechanisms to enable recovery of

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program expenses. This section provides an overview of several of the more common approaches.

4.2.1 Rate Case Recovery

The most straightforward approach to recovery of program costs as expenses involves recovery in base rates as an element of the utility revenue requirement. Energy efficiency program costs are estimated for the relevant period, added to the utility's revenue requirement, and recovered through customer rates that were set based on this revenue requirement and estimated sales. Rate cases typically involve an estimate of known future costs, given that the rates that emerge from the case are applied going forward. For example, a utility and its commission might conduct a rate case in 2007 to establish the rates that will apply beginning in 2008. Therefore, the utility will estimate (and be seeking approval to incur) the costs associated with the energy efficiency program in 2008 and annually thereafter. The approved level of energy efficiency spending will be included in the allowed revenue requirement, and the rates taking effect in 2008 should include an amount that will recover the utility's budgeted program costs over the course of the year based on the level of annual sales estimated in the rate case. Although actual program expenses rarely match the amount of revenue collected for those programs in real-time, in principle, program expenses incurred will match revenue received by the end of the year. This approach works best when annual energy efficiency expenditures are constant on average.

4.2.2 Balancing Accounts with Periodic True-Up

Practice rarely matches principle, however, particularly with respect to energy efficiency program costs. The estimates of program costs used as the basis for setting rates are based in large part on assumed customer participation in the efficiency programs. However, participation is difficult to predict at a level of precision that ensures that annual expenditures will match annual revenue, especially in the early years of programs. Under-recovery of expenses occurs if participation in programs exceeds estimates and actual program costs rise. Regulatory commissions and utilities frequently have implemented various types of balancing mechanisms to ensure that customers do not pay for costs never incurred, and that utilities are not penalized because participation and program costs exceeded estimates. Such approaches also enable utilities to more flexibly ramp program activity (and associated spending) up or down. These mechanisms also often include some type of periodic prudence review to ensure that costs incurred in excess of those estimated in the rate case were prudently incurred.

The mechanics of a balancing account can work in a number of ways. Balances can simply be carried (typically with an associated carrying charge) until the next rate case, at which point they are "trued-up."[3] A positive balance could be used to reduce the level of expenses authorized for recovery in the future period, and a negative balance could be added in full to the authorized revenues for the future period or could be amortized. Alternatively, the balances can be self-adjusting by using a surcharge or tariff rider (discussed below), and some states allow annual true-up outside of general rate case proceedings.[4]

4.2.3 Pros and Cons

Table 4-1 describes general pros and cons associated with the expensing of program costs.

4.2.4 Case Study: Arizona Public Service Company (APS)

In June 2003, APS filed an application for a rate increase and a settlement agreement was signed between APS and the involved parties in August 2004. The settlement addresses DSM and cost recovery, allowing $10 million each year in base rates for eligible expenses, as well as an adjustment mechanism for program expenses beyond $10 million.

- The settlement agreement embodied in Order No. 67744 issued in April of 2005, under Docket No. E-01345A-03-0437[5] includes the following provisions:
- Included in APS' total test year settlement base rate revenue requirement is an annual $10 million base rate DSM allowance for the costs of approved "eligible DSM-related items," defined as the planning, implementation, and evaluation of programs that reduce the use of electricity by means of energy efficiency products, services, or practices. Performance incentives are included as an allowable expense.

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Table 4-1. Pros and Cons of Expensing Program Costs

Pros
• Expensing treatment is generally consistent with standard utility cost accounting and recovery rules.
• Avoids the creation of potentially large regulatory assets and associated carrying costs.
• Provides more-or-less immediate recovery of costs and reduces recovery risk.
• The use of balancing mechanisms outside of a general rate case ensures more timely recovery when efficiency program costs are variable and prevents significant over- or under-recovery from being carried forward to the next rate case.
Cons
• A combination of infrequent rate cases and escalating expenditures can lead to under-recovery absent a balancing mechanism.
• Can be viewed as single-issue ratemaking.
• If annual energy efficiency expenditures are large, lump sum recovery can have a measurable short-term impact on rates.
• Some have argued that expensing creates unequal treatment between the supply-side investments (which are rate-based) and the efficiency investments that are intended to substitute for new supply.

- In addition to expending the annual $10 million base rate allowance, APS is obligated to spend, on average, at least another $6 million annually on approved eligible DSM-related items. These additional amounts are to be recovered by means of a DSM adjustment mechanism.
- All DSM programs must be pre-approved before APS may include their costs in any determination of total DSM costs incurred.
- The adjustment mechanism uses an adjustor rate, initially set at zero, which is to be reset on March 1, 2006, and thereafter on March 1 of each subsequent year. The adjustor is used only to recover costs in arrears. APS is required to file its proposal for spending in excess of $10 million prior to the March 1 adjustment. The per-kilowatt-hour charge for the year will be calculated by dividing the account balance by the number of kilowatt-hours used by customers in the previous calendar year.
- General Service customers that are demand-billed will pay a per-kilowatt charge instead of a per-kilowatt-hour charge. The account balance allocated to the General Service class is divided by the kilowatt billing determinant for the demand-billed customers in that class to determine the per-kilowatt DSM adjustor charge. The DSM adjustor applies to all customers taking delivery from the company, including direct access customers.

4.2.5 Case Study: Iowa Energy Efficiency Cost Recovery Surcharge

Until 1997, electric energy efficiency program costs were tracked in deferred accounts with recovery in a rate case via capitalization and amortization. Since then investor-owned utilities in Iowa, pursuant to Iowa Code 2001, Section 476.6,[6] recover energy efficiency program-related costs through an automatic rate pass-through reconciled annually to prevent over- or under-recovery (i.e., costs are expensed and recovered concurrently). Program costs are allocated within the rate classes to which the programs are directed, although certain program costs, such as those associated with low income and research and development programs, are allocated to all customers. The cost recovery surcharge is recalculated annually based on historical collections and expenses and planned budgets. The energy efficiency costs recovered from customers during the previous period are compared to those that were allowed to be recovered at the time of the prior adjustment. Any over- or under-collection, any ongoing costs, and any change in forecast sales, are used to adjust the current energy efficiency cost recovery factors. The statute requires that each utility file, by March 1 of each year, the energy efficiency costs proposed to be recovered in rates for the 12-month recovery period. This period begins at the start of the first utility billing month at least 30 days following Iowa Utility Board approval.

199 Iowa Administrative Code Chapter 35[7] provides the detailed cost recovery mechanism in place in Iowa. These details are summarized in Appendix D.

4.2.6 Case Study: Florida Electric-Rider Surcharge

The Florida Energy Efficiency and Conservation Act (FEECA) was enacted in 1980 and required the Florida Commission to adopt rules requiring electric utilities to implement cost-effective conservation and DSM programs. Florida Administrative Code Rules 25-17.001 through 25-17.015 require all electric utilities to implement cost-effective DSM programs. In June 1993, the commission revised the existing rules and required the establishment of numeric goals for summer and winter demand and annual energy sales reductions.

In order to obtain cost recovery, utilities are required to provide a cost-effectiveness analysis of each program using the ratepayer impact measure, total resource cost, and participant cost tests.

Investor-owned electric utilities are allowed to recover prudent and reasonable commission-approved expenses through the Energy Conservation Cost Recovery (ECCR) clause. The commission conducts ECCR proceedings during November of each year. The commission determines an ECCR factor to be applied to the energy portion of each customer's bill during the next calendar year. These factors are set based on each utility's estimated conservation costs for the next calendar year, along with a true-up for any actual conservation cost under- or over-recovery for the previous year (Florida PSC, 2007).

The procedure for conservation cost recovery is described by Florida Administrative Code Rule 25-17.015(1);[8] details are included in Appendix D. Table 4-2 shows the current cost recovery factors.

Florida Power and Light's (FPL's) recent cost recovery filing provides some insight into the nature of the adjustment process:

> FPL projects total conservation program costs, net of all program revenues, of $175,303,326 for the period January 2007 through December 2007. The net true-up is an over recovery of $4,662,647, which includes the final conservation true-up over recovery for January 2005, through December 2005, of $5,849,271 that

Table 4-2. Current Cost Recovery Factors in Florida

	Residential Conservation Cost Recovery Factor (cents per kWh)	Typical Residential Monthly Bill Impact (based on 1,000 kWh)
FPL	0.169	$1.69
FPUC	0.060	$0.60
Gulf	0.088	$0.88
Progress	0.169	$1.96
TECO	0.073	$0.73

Source: Florida PSC, 2007.

was reported in FPL's Schedule CT-1, filed May 1, 2006. Decreasing the projected costs of $175,303,326 by the net true-up over-recovery of $4,662,647 results in a total of $170,640,679 of conservation costs (plus applicable taxes) to be recovered during the January 2007, through December 2007, period. Total recoverable conservation costs and applicable taxes, net of program revenues and reflecting any applicable over- or under-recoveries are $170,705,441, and the conservation cost recovery factors for which FPL seeks approval are designed to recover this level of costs and taxes.

4.3 Capitalization and Amortization of Energy Efficiency Program Costs

Capitalization as a cost recovery method is typically reserved for the costs of physical assets such as generating plant and transmission lines. However, some states allow the costs of energy efficiency and demand-response programs to be treated as capital items, even though the utility is not acquiring any physical asset. In the case of an investor-owned utility, such capital items are included in the utility's rate base. The utility is allowed to earn a return on this capital, and the investment is depreciated over time, with the depreciation charged as an expense. Depending on precisely how a capitalization mechanism is structured, it can serve as a strict cost-recovery tool or as a utility performance incentive mechanism as well. A principle argument made in favor of capitalizing energy efficiency program costs is that this treatment places demand-and supply-side expenditures on an equal financial footing.[9,10]

Capitalization[11] currently is not a common approach to energy efficiency program cost recovery, although during the peak of the last major cycle of utility energy efficiency investment during the late 1980s and early 1990s many states allowed or required capitalization.[12]

Capitalization of energy efficiency costs as a cost recovery mechanism first appeared in the Pacific Northwest (Reid, 1988). Oregon and Idaho were the first two states to allow capitalization of certain selected costs in the early 1980s. Washington soon followed with statutory authority for ratebasing that included authorization for a higher return on energy efficiency investments. Puget Power1[3] in Washington was allowed to ratebase all of its energy efficiency–related costs using a 10-year recovery period with no carrying charges applied to the costs incurred between rate cases. Montana followed Washington in 1983 and adopted a similar mechanism. In 1986, Wisconsin switched from expensing the conservation expenditures to capitalization and allowed a large amount of direct investment to be capitalized with a 10-year amortization period.

With a very few exceptions, capitalization is no longer the method of choice for energy efficiency cost recovery in these states. The decline in the popularity of this approach can be attributed to a variety of factors, including the general decline in utility energy efficiency investment. However, in several states capitalization was abandoned, in part because the total costs associated with recovery (given the cost of the return on investment) were rising rapidly.

4.3.1 The Mechanics of Capitalization

As a simplified example, suppose that a utility spends $1 million in each of five years for its energy efficiency programs, and it is allowed to capitalize and amortize these investments over a 10-year recovery period uniformly. Table 4-3 illustrates the yearly change in revenue requirements, assuming a 10 percent rate of return on the unrecovered balance.

By the end of the 15-year amortization period, the total amount collected by the utility through rates is $7,250,000. Just as the total cost of purchasing a home will be lower with a shorter mortgage, shorter amortization periods yield a lower total cost for recovery of the energy efficiency program expenditures. Similarly, although the total amount recovered is almost 50 percent higher in this case than the direct cost of the energy efficiency program, the $2,250,000 represents a legitimate cost to the utility which comes from the need to carry an unrecovered balance on its books. Conceptually, a utility will be indifferent to immediate recovery of program costs as an expense and capitalization, as the added cost of capitalization should be equal to the cost to the utility of effectively lending the $5 million to customers. However, in the cases of those states that have allowed utilities to earn a return on energy efficiency investments that exceeds their weighted cost of capital, this added return constitutes an incentive for investment in energy efficiency that goes beyond that provided for traditional capital investments.

4.3.2 Issues

The length of time over which an energy efficiency investment is amortized (essentially the rate of depreciation), and the capital recovery rate or rate-of-return on the unamortized balance of the investment, both affect the total cost to customers of the utility.

Amortization and Depreciation

When an expenditure is capitalized, the recovery of this expenditure is spread over several years, with predetermined amounts recovered in rates each year during the recovery or amortization period. The depreciation or amortization rate is the fraction of unrecovered cost that is recovered each year. Tax law and regulation generally govern the specific rate used for different types of capital investments such as generating or distribution plant and equipment and other physical structures. However, since the costs of energy efficiency programs typically are not considered capital items, there is no universally accepted depreciation rate applied to energy efficiency program costs that are capitalized. An early study (Reid, 1988) of energy efficiency capitalization found that amortization programs for conservation expenditures ranged from three to 10 years. For example, Washington and Wisconsin allowed a 10-year recovery period for amortization.

Table 4-3. Illustration of Energy Efficiency Investment Capitalization

End-of-year	Annual Energy-Efficiency Expenditure	Cumulative Energy-Efficiency Expenditure	Depreciation	Unamortized Balance	Return on Unrecovered Investment	Incremental Revenue Requirements
1	1,000,000	1,000,000	$100,000	$900,000	$90,000	$190,000
2	1,000,000	2,000,000	$200,000	$1,700,000	$170,000	$370,000
3	1,000,000	3,000,000	$300,000	$2,400,000	$240,000	$540,000
4	1,000,000	4,000,000	$400,000	$3,000,000	$300,000	$700,000
5	1,000,000	5,000,000	$500,000	$3,500,000	$350,000	$850,000
6			$500,000	$3,000,000	$300,000	$800,000
7			$500,000	$2,500,000	$250,000	$750,000
8			$500,000	$2,000,000	$200,000	$700,000
9			$500,000	$1,500,000	$150,000	$650,000
10			$500,000	$1,000,000	$100,000	$600,000
11			$400,000	$600,000	$60,000	$460,000
12			$300,000	$300,000	$30,000	$330,000
13			$200,000	$100,000	$10,000	$210,000
14			$100,000	$0	$0	$100,000
15/Total	5,000,000		$5,000,000		$2,250,000	$7,250,000

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Massachusetts used the lifetime of the energy efficiency equipment for the recovery period.

Rate of Return[14]

Just as the interest rate on a home mortgage can greatly affect both the monthly payment and the total cost of the home, the rate of return allowed on the unamortized cost of an energy efficiency program can significantly affect the cost of that program to ratepayers. Rates-of-return for investor-owned utilities are set by state regulators based on the relative costs of debt and equity. In the case of publicly and cooperatively owned utilities, the return much more closely mirrors the cost of debt. The ROE, in turn, is based on an assessment of the financial returns that investors in that utility would expect to receive—an expectation that is influenced by the perceived riskiness of the investment. This riskiness is related directly to the perceived likelihood that a utility will, for some reason, not be able to earn enough money to pay off the investment.

Unless the level of energy efficiency program investment is significant relative to a utility's total unamortized capital investment, the relative riskiness of energy efficiency versus supply-side investments is not a major issue. However, if this investment is significant, the relative risk of an energy efficiency investment can become an issue for a variety of reasons, including:

- These resources are not backed by physical assets. While a utility actually owns gas distribution mains or generating plants, it does not own an efficient air conditioner that a customer installs through a utility program. If energy efficiency spending is accrued for future recovery, either by expensing or amortization, this accrual is considered as a "regulatory asset"—an asset created by regulatory policy that is not backed by an actual plant or equipment. Carrying substantial regulatory assets on the balance sheet can hurt a utility's financial rating.

- The investment becomes more susceptible to disallowance. Recovery of a capital investment typically is allowed only for investments deemed prudent and used-and-useful. Because energy efficiency programs are based on customer behavior, and because that behavior is difficult to predict, it is possible that the investment being recovered does not actually produce its intended benefit. This result could lead regulators to conclude that the investment was not prudent or used-and-useful. This risk owes more to the fact that energy efficiency program effectiveness is subject to ex post evaluation. As program design and implementation experience grows, program realization rates (the ratio of actual to expected savings) increases, and this risk diminishes. It is not clear that this risk is any different with respect to its ultimate effect than the risks associated with the construction and operation of a utility plant.

- Potential uncertainty arising from policy changes that govern energy efficiency incentive mechanisms heightens the risk. Although both supply- and demand-side resources are subject to policy risk, the modularity and short lead-times associated with demand-side resources (which is a distinct benefit from a resource planning perspective) also create more opportunities to revisit the policies governing energy efficiency expenditure and cost recovery. The fact that energy efficiency program costs are regulatory assets in theory, means that the regulatory policy underlying those assets can change with changes in the regulatory environment. The pressure to modify policies governing recovery of program costs has increased historically as the size of these assets has grown with increases in program funding.

4.3.3 Pros and Cons

Based on experience to date, capitalization and amortization carries pros and cons as illustrated in Table 4-4.

4.3.4 Case Study: Nevada Electric Capitalization with ROE Bonus

Nevada is the only state currently that allows recovery of energy efficiency program costs using capitalization *as well as* a bonus return on those costs. Development and administration of energy efficiency programs by Nevada's regulated electric utilities takes place within the context of an integrated resource planning process combined with a resource portfolio standard that allows energy efficiency programs to fulfill up to 25 percent of the utilities' portfolio requirements. Over the past several years spending on energy efficiency programs has risen substantially, both as a response to rapid growth in electricity demand and as Nevada Power and Sierra Pacific Power have attempted to maximize the contribution of energy efficiency to portfolio requirements as those requirements grow.

All prudently incurred costs associated with energy efficiency programs are recoverable pursuant to the Nevada Administrative Code 704.9523. A utility may seek to recover any costs associated with approved programs for conservation and DSM, including labor, overhead, materials, incentives paid to customer, advertising, and program monitoring and evaluation.

Mechanically, the Nevada mechanism works as follows for those approved programs not already included in a utility's rate base:

- The utility tracks all program costs monthly in a separate account.
- A carrying cost equal to 1/12 of the utility's annual allowed rate of return is applied to the balance in the account.
- At the time of the next rate case, the balance in the account (including program costs and carrying costs) is cleared from the tracking account and moved into the utility's rate base.
- The commission sets an appropriate amortization period for the account balance based on its determination of the life of the investment.
- The utility applies a rate of return to the unamortized balances equal to the authorized rate of return plus 5 percent (for example a 10.0 percent return becomes 10.5 percent).

Nevada's current cost recovery/incentive structure has been in place since 2001. However, with the recent rapid rise in utility energy efficiency program spending, concerns also have arisen with respect to the structure of the mechanism and its effect on the utilities' investment incentives. These concerns prompted the Nevada Public Service Commission to open an investigatory docket in late 2006. In its Revised Order in Docket Nos. 06-0651 and 07-07010 on January 30, 2007, the commission wrote that:

Table 4-4. Pros and Cons of Capitalization and Amortization

Pros

- Places energy efficiency investments on more of an equal footing with supply-side investment with respect to cost recovery
- Capitalization can help make up for the decline in utility generation and transmission and distribution assets expected to occur, as energy efficiency defers the need for new supply-side investment.
- As part of this equalization, enables the utility to earn a financial return on efficiency investments.
- Smoothes the rate impacts of large swings in annual energy efficiency spending.

Cons

- Treats what is arguably an expense as a capital item.
- Creates a regulatory asset that can grow substantially over time; because this asset is not tangible or owned by utility, it tends to be viewed as more risky by the financial community.
- Delays full recovery and boosts recovery risk.
- To the extent that the return on the energy efficiency program investment is intended to provide a financial incentive for the utility, this incentive is not tied to program performance.
- Raises the total dollar cost of the efficiency programs.

> [We] believe that appropriate incentives for utility DSM programs are necessary. The exact nature and form of incentives that should be offered for such programs involve a number of factors, including the regulatory and statutory environment. The current incentives for DSM were implemented in 2001 when the companies had few, if any, incentives to implement DSM programs. The enactment of A.B. 3 changed both the regulatory and statutory context. Utilities now have incentives to implement DSM to meet portions of their respective renewable portfolio standard requirements. Nevada Power Company's expenditures will increase almost four times compared to pre A.B. 3 during this action plan. Given these changes, it is now time to reexamine the mandatory package of incentives provided to DSM programs. This includes the types and categories of costs eligible for expense treatment, as well as prescribed incentives. The commission therefore directs its secretary to open an investigation and rulemaking into the appropriateness of DSM cost recovery mechanisms and incentives.

In early 2007, the commission asked all interested parties to comment on four specific issues, as identified below:

- What are the public policy objectives of an incentive structure? i.e., Should only the most cost-effective programs be incented? Should only the most strategic programs be incented?
- Does the current incentive structure provide the appropriate incentives to fulfill each public policy objective?
- Are there alternative incentive structures that the commission should consider? If so, what are these incentives and how would each further the goals identified above?
- How should the current incentive structure be redesigned? i.e., what expenses should be included in the incentive mechanism? What should be the basis for determining incentives?

Commission staff have argued that the underlying rationale for utility energy efficiency investments is found in the integrated resource planning process. Staff noted that utilities should be inclined to pursue those programs that contribute to the least-cost resource mix. The addition of the resource portfolio requirement and the ability to meet up to 25 percent of that requirement provides further incentive to pursue energy efficiency investment. At the same time, staff argued that the current cost recovery mechanism, with the addition of the five percentage point rate of return bonus, provided no incentive for effective program performance and in fact, simply encouraged additional spending with no consideration for the implementation outcome—an argument echoed by the Attorney General's Bureau of Consumer Protection. Staff recommended that the ideal solution is to tie incentives to program performance and to share program net benefits with ratepayers.

Nevada Power Company and Sierra Pacific Power Company have endorsed the existing mechanism as providing appropriate incentives to fulfill the public policy objective of achieving a net benefit for customers while providing a stable and motivating incentive for the utility. According to the companies, the current incentive scheme with the bonus rate of return recognizes the increased risks associated with DSM investments compared to the supply-side investments, and they argue that changing the existing incentive structure will create uncertainty and therefore, increase the perceived risk associated with energy efficiency investments. They further argue that the integrated resource plan review process ensures that program budgets are given detailed review.

4.4 Notes

1. Depreciation of capital equipment is, however, treated as an expense.

2. An "opt-out" allows a customer, typically a large customer, to elect to not participate in a utility program and to avoid paying associated program costs. Some states do not allow opt-outs, but will allow large customers to spend the monies that otherwise would be collected from them by utilities for efficiency projects in their own facilities. This often is called "self-direction."

3. Wisconsin investor-owned utilities use "escrow accounting" as a form of a balancing account. Should the Public Service

Commission authorize a utility to incur specific program costs during a period between rate cases, these costs are recorded in an escrow account. Carrying charges are applied to the balance. The balance of the escrow account is cleared into the revenue requirement at the time of the next rate case (typically every two years).

4. As discussed elsewhere in this paper, addressing recovery of program costs as a separate matter apart from all other utility cost changes could be considered single-issue ratemaking which can be prohibited.

5. Order No. 67744, *In the Matter of the Application of the Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return, and for Approval of Purchased Power Contract,* Docket No. E-01345-A-03-0437, accessed at <www.azcc.gov/divisions/utilities/electric/APS-FinalOrder.pdf>.

6. Iowa Code 2001: Section 476.6, accessed at <www.legis.state.ia.us/IACODE/2001/476/6.html>.

7. 199 Iowa Administrative Code Chapter 35, accessed at <www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf>.

8. Florida Administrative Code Rule 25-17.015(1), accessed at <www.flrules.org/gateway/RuleNo.asp?ID=25-17.015>.

9. Some have argued that capitalization and amortization of energy efficiency program costs provides an incentive to utilities to invest in energy efficiency without regard to the performance of the programs. See the Nevada case study below for a broader treatment of this issue.

10. From a narrow theoretical perspective, there should be no significant financial difference between expensing and capitalization. The return on capital is intended to compensate a utility for the cost of money used to fund an activity. For investor-owned utilities, this compensation includes payment to equity investors. However, if program expenses are immediately expensed—that is, if the utility can immediately recover each dollar it expends on a program—the utility does not need to "advance" capital to fund the programs, and therefore, there is no cost incurred by the utility.

11. This Report uses the generic term "capitalization" as opposed to "ratebasing," since, in some states, energy efficiency program costs technically are not included in a utility's rate base but are treated in a similar fashion via capitalization.

12. The following states either have used in the past or continue to use some form of capitalization of energy efficiency costs: Oregon, Idaho, Washington, Montana, Texas, Wisconsin, Nevada, Oklahoma, Connecticut, Maine, Massachusetts, Vermont, and Iowa. With the exception of Nevada, most of these states are no longer using capitalization, though it remains an option. See Reid, M. (1988). *Ratebasing of Utility Conservation and Load Management Programs. The Alliance to Save Energy.*

13. Puget Power is now known as Puget Sound Energy.

14. "Rate of return" is used in this context to refer to the rate applied to an unamortized balance that is used to represent the cost of money to the utility. In the case of investor-owned utilities, this rate is usually a weighted average of the interest rate on debt and the allowed return on equity.

5: Lost Margin Recovery

This chapter provides a practical overview of alternative mechanisms to address the recovery of lost margins and presents their pros and cons. Detailed case studies are provided for each mechanism.

5.1 Overview

Chapter 2 of the Action Plan provides a concise explanation of the throughput incentive and a summary of options to mitigate the incentive. This incentive has been identified by many as the primary barrier to aggressive utility investment in energy efficiency. Policy expectations that utilities aggressively pursue the implementation of energy efficiency programs create a conflict of interest for utilities in that they cannot fulfill their obligations to their shareholders while simultaneously encouraging energy efficiency efforts of their customers, which will reduce their sales and margins in the presence of the throughput incentive.

Any approach aiming to eliminate, or at least neutralize, the impact of the throughput incentive on effective implementation of energy efficiency programs must address the issue of lost margins due to successful energy efficiency programs. Two major cost recovery approaches have been tried since the 1980s with this objective in mind; *decoupling* and *lost revenue* recovery.[1] A third approach, known generically as *straight fixed-variable* (SFV) ratemaking, conceptually provides a solution to the problem by allocating most or all fixed costs to a fixed (non-volumetric) charge. Under such a rate design, reductions in the volume of sales do not affect recovery of fixed costs. While conceptually appealing, this approach carries with it complex implementation issues associated with the transition from a structure that recovers fixed costs via volumetric charges to a SFV structure. It also can reduce the financial incentive for end-users to pursue energy efficiency investments by reducing the value that consumers realize by reducing the volume of consumption—an issue more likely to impact electricity consumers than gas customers, since commodity cost represents a larger share of a consumer's total gas bill. While it has seen application in the natural gas industry, SFV ratemaking is uncommon in the electric industry (see American Gas Association, 2007).

5.2 Decoupling

The term "decoupling" is used generically to represent a variety of methods for severing the link between revenue recovery and sales. These methods vary widely in scope, and it is rare that a mechanism fully decouples sales and revenues. Some approaches provide for limited true-ups in attempts to ensure that utilities continue to bear the risks for sales changes unrelated to energy efficiency programs. Some focus on preserving recovery of lost margins. This focus recognizes that a sales reduction will be accompanied by some cost reduction, and therefore, the total revenue requirement will be lower. Truing up total revenue would, in such cases, boost utility earnings.

In recent years, decoupling has re-emerged as an approach to address the margin recovery issue facing utilities implementing substantial energy efficiency program investments. Decoupling can be defined generally as a separation of revenues and profits from the volume of energy sold and, in theory, makes a utility indifferent to sales fluctuations. Mechanically, decoupling trues-up revenues via a price adjustment when actual sales are different than the projected or test year levels.

Decoupling mechanisms appear under various names including the following listed by the National Regulatory Research Institute (Costello, 2006): Conservation Margin Tracker; Conservation-Enabling Tariff; Conservation Tariff; Conservation Rider; Conservation and Usage Adjustment

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(CUA) Tariff; Conservation Tracker Allowance; Incentive Equalizer; Delivery Margin Normalization; Usage per Customer Tracker; Fixed Cost Recovery Mechanism; and Customer Utilization Tracker. Although often cited as a solution to the throughput issue raised by energy efficiency programs, decoupling is also a mechanism that often is generally suggested as a way to smooth earnings in the face of sales volatility. Natural gas utilities have been among the strongest advocates of decoupling because of its ability to moderate the impacts of abnormal weather and declining usage per customer, in addition to its ability to mitigate the under-recovery of fixed costs caused by energy efficiency programs (see American Gas Association, 2006a).

A decoupling mechanism will sometimes include a balancing account in order to ensure the exact collection of the revenue requirement, although this approach typically is used only if there is an extended period between rate adjustments. If revenues collected deviate from allowed revenues, the difference is collected from or returned to customers through periodic adjustments or reconciliation mechanisms. If a successful energy efficiency program reduces sales, there will not be any loss in revenue resulting from these energy efficiency programs. If sales turn out to be higher than the projected, the excess revenue is returned to the ratepayer.

There are two major forms of revenue decoupling—those linked to total revenue and those focused on revenue per customer: the revenue a utility is allowed to earn is capped in the former, and the revenue per customer is capped in the latter. The primary advantage of a revenue-per-customer model is that it recognizes the link between a utility's revenue requirement and its number of customers. For example, if a decoupling mechanism caps total revenue, and if the utility experiences a net increase in customers, all else being equal, the allowed level of revenue will fall short of the cost of serving the additional customers, leading to a drop in earnings. A revenue-per-customer mechanism allows total revenue to grow (or fall) as the number of customers and associated costs rise (fall).

Table 5-1 shows a simple example (constructed similarly to the example in Eto et al., 1994) illustrating the basic decoupling mechanism with a balancing account.

For year 1, the revenue requirement of $100 is authorized through the general rate case. Given projected sales of 1,000 therms, the price is determined to be 10

Table 5-1. Illustration of Revenue Decoupling

		A	B	C (A÷B)	D	E (D÷B)	F	G (E×F)	H (G–A)	I (D–G)
	Year	Revenue Requirements	Expected Sales (Therms)	Price Set in the Rate Case (Therms)	Allowed to Collect	Actual Price ($/Therm)	Actual Sales (Therms)	Actual Revenue	Changes Between Revenue Requirement and Actual Revenue	Balance Account
Rate Case 1	1	$100.00	1,000	0.100	$100.00	0.100	1,100	$110.00	$10.00	-$10.00
	2	$100.00	1,000	0.100	$90.00	0.090	990	$89.10	-$10.90	$0.90
Rate Case 2	3	$111.10	1,010	0.110	$112.00	0.111	1,010	$112.00	$0.90	$0.00

cents/therm. If actual sales are 1,100 therms, then at the rate of 0.1 $/therm, the actual realized revenue is $110. The utility places the $10 difference between the actual revenue and the allowed revenue in a balancing account. The next year, the utility needs to collect only $90 to reach the $100 authorized revenue and the price per therm is set at 9 cents. If the sales were indeed 1,000 therms, the utility would make $90, and with the $10 in the balancing account, it would exactly meet the authorized revenue. However, in this example, the sales are 990 therms, and utility revenue is $89.10 at 9 cents/therm. The utility needs to collect 90 cents from the ratepayers.

Suppose that the revenue requirement is reset to $111.10 at the projected sales level of 1,010 therms. The utility needs to collect the balance in the balancing account and its authorized revenue of $111.10, a total of $112. At the projected sales level of 1,010, the price needs to be set at 11.1 cents per therm to recover $112. Suppose that the utility's sales are actually equal to the projected sales of 1,010. The utility recovers exactly $112 and there is a zero balance left in the balancing account.

Under the revenue-per-customer cap approach, the actual revenues collected *per customer* are compared to the authorized revenues *per customer,* and the balancing account maintains the over- or under-earnings. A simple example of the revenue cap-per-customer approach is illustrated in Table 5-2.

In this example, the revenue per customer to be collected is fixed or capped. Assuming monthly adjustments, actual revenues collected per customer are compared

Performance-Based Ratemaking and Decoupling

Performance-Based Ratemaking (PBR) is an alternative to traditional return on rate base regulation that attempts to forego frequent rate cases by allowing rates or revenues to fluctuate as a function of specified utility performance against a set of benchmarks. One form of PBR embodies a revenue cap mechanism that functions very much like a decoupling, wherein price is allowed to fluctuate as a way to true-up actual revenues to allowed revenues. The revenue-cap PBR mechanism can be more complex, incorporating a variety of specific adjustments to both price and revenue. In most cases, if a utility operates under revenue-cap PBR, sales and revenues are decoupled for purposes of energy efficiency investment, although specific adjustments may be required to allow prices to be adjusted for changes in actual program costs as well as changes in margins.

Table 5-2. Illustration of Revenue per Customer Decoupling

A		Revenue requirements ($)	100
B		Expected sales (therms)	1,000
C	**(A÷B)**	Price set in the rate case ($/therm)	0.1
D		Number of customers	100
E	**(A÷D)**	Allowed revenue per customer ($/therm)	1
F		Actual sales (therms)	950
G	**(C×F)**	Actual revenue ($)	95
H		Actual number of customers	101
I		Allowed revenue ($)	101
J	**(I–G)**	Revenue adjustment ($)	6

to the allowed revenue per customer for that month. The difference is recorded in a balancing account and reconciled periodically. In this case, because of customer growth, the utility is allowed to collect $6 more than the initial revenue requirement.

Revenue decoupling has been a part of gas ratemaking for over two decades, with revenue cap-per-customer the more commonly encountered approach.[2] Interest has increased over the past several years due to increased customer conservation in response to high gas prices and utility-funded energy efficiency initiatives. In addition, natural gas usage per household has declined more than 20 percent since the 1980s and is projected to continue to decline in the future in many jurisdictions (Costello, 2006). In such cases, decoupling provides an automatic adjustment mechanism that allows the utility to be revenue neutral and can help defer otherwise needed rate cases.

Early experience with decoupling, as recounted in Chapter 2 of the Action Plan, provides important lessons.[3] In 1991, the Maine PUC adopted a revenue decoupling mechanism in the form of revenue-per-customer cap for Central Maine Power (CMP) on a three-year trial basis. The utility's allowed revenue was determined through a rate case and adjusted annually in accordance with changes in the number of customers. CMP was allowed to file a rate case at any time to adjust its authorized revenues. With the economic downturn Maine experienced around the time the mechanism was in place, sales dipped significantly leading to a large unrecovered balance ($52 million by the end of 1992) that needed to be charged to the ratepayers. In fact, the portion of the energy efficiency-related drop in the sales was very small. Nevertheless, the program in its entirety was terminated in 1993.

Currently, a number of jurisdictions are investigating the advantages and disadvantages of decoupling, including Arizona, Colorado, Delaware, the District of Columbia, Delaware, Hawaii, Kentucky, Maryland, Michigan, New Hampshire, New Mexico, Pennsylvania, Tennessee, and Virginia. Sixteen states have adopted either gas or electric decoupling programs for at least one utility. Arkansas, New York, Utah, Oregon, Washington, Idaho, and Minnesota are among the states recently adopting decoupling programs.[4]

Table 5-3 suggests the possible pros and cons of decoupling. The specific nature of the decoupling mechanism and, in particular, the nature of adjustments for factors such as weather and economic growth, will determine the extent to which the link between sales and profits is affected.

5.2.1 Case Study: Idaho's Fixed Cost Recovery Pilot Program

The mechanism adopted in Idaho to address the impacts of efficiency program-induced changes in sales should not be viewed as decoupling in the broadest sense of that term. While it contains a number of the elements found in decoupling plans, it is focused specifically on recovery of lost fixed-cost revenues. The Idaho Public Utilities Commission initiated Case No. IPC-04-15 in August 2004, to investigate financial disincentives to investment in energy efficiency by Idaho Power Company. A series of workshops was conducted, and a written report was filed with the commission in early 2005. The report pointed to two action items:

1. The development of a true-up simulation to track what might have occurred if a decoupling or true-up mechanism had been implemented for Idaho Power at the time of the last general rate case.

2. The filing of a pilot energy efficiency program that would incorporate both performance incentives and fixed-cost recovery.

During the investigation, the parties agreed that there were disincentives preventing higher energy efficiency investment by Idaho Power, but no agreement was reached on whether or not the return of lost fixed-cost revenues would result in removing the disincentives. The parties agreed to conduct a simulation of the proposed mechanism, the results of which indicated that lost fixed-cost revenues, in fact, produced barriers to energy efficiency investments and, therefore, a three-year pilot mechanism to allow recovery of fixed-cost revenue losses should be approved.

Table 5-3. Pros and Cons of Revenue Decoupling

Pros
• Revenue decoupling weakens the link between sales and margin recovery of a utility, reducing utility reluctance to promote energy efficiency, including building codes, appliance standards, and other efficiency policies.
• Through decoupling, the utility's revenues are stabilized and shielded from fluctuations in sales. Some have argued that this, in turn, might lower its cost of capital.[5] (For a discussion of this issue, see Hansen, 2007, and Delaware PSC, 2007). The degree of stabilization is a function of adjustments made for weather, economic growth, and other factors (some mechanisms do not adjust revenues for weather or economic growth-induced changes in sales).[6]
• Decoupling does not require an energy efficiency program measurement and evaluation process to determine the level of under-recovery of fixed costs.[7]
• Decoupling has a low administrative cost relative to specific lost revenue recovery mechanisms.
• Decoupling reduces the need for frequent rate cases and corresponding regulatory costs.
Cons
• Rates (and in the case of gas utilities, non-gas customer rates) can be more volatile between rate cases, although annual caps can be instituted.
• Where carrying charges are applied to balancing accounts, the accruals can grow quickly.
• The need for frequent balancing or true-up requires regulatory resources; may be a lesser commitment than required for frequent rate cases.

Idaho Power filed an application with the Idaho Public Utilities Commission in January of 2006, and requested authority to implement a fixed cost adjustment (FCA) decoupling or true-up mechanism for its residential and small General Service customers. The commission staff, the NW Energy Coalition, and Idaho Power negotiated a settlement agreement, and the commission approved a Joint Motion for Approval of Stipulation in December 2006.

The commission issued Order No. 30267 (Idaho PUC, 2007) approving the FCA as a three-year pilot program, noting that either staff or Idaho Power can request discontinuance of the pilot. Program implementation began on January 1, 2007, and will last through December 31, 2009, plus any carryover. The first rate adjustment will occur June 1, 2008, and subsequent rate adjustments will occur on June 1 of each year during the term of the pilot.

The proposed FCA is applicable to residential service and small General Service customers because, as the company noted, these two classes present the most fixed-cost exposure for the company. The FCA is designed to provide symmetric rate adjustment (up or down) when fixed-cost recovery per customer varies above or below a commission-established level. While this approach fits the conventional description of a decoupling mechanism, Idaho Power noted that a more accurate description of the mechanism is a "true-up." The fixed-cost portion of the revenue requirement would be established for residential and small General Service customers at the time of a general rate case. Thereafter, the FCA would provide the mechanism to true-up the collection of fixed costs per customer to recover the difference between the fixed costs actually recovered through rates and the fixed costs authorized for recovery in the company's most recent general rate case. The FCA mechanism incorporates a 3 percent cap on annual increases, with carryover of unrecovered deferred costs to subsequent years.

The actual number of customers in the adjustment year for each customer class to which the mechanism applies is multiplied by the assumed fixed cost per customer, which is determined by dividing the total fixed costs by the total number of customers from the last general rate case. This allowed fixed-cost recovery amount is compared with the amount of fixed costs actually recovered by the Idaho Power. The actual fixed-cost recovery is determined by multiplying the weather-normalized sales for each class by the fixed-cost per kilowatt-hour rate also determined in the general rate case. The difference between the allowed and the actual fixed-cost recovered amounts is the fixed-cost adjustment for each class.

For customer billing purposes only, the commission-approved FCA adjustment is combined with the conservation program funding charge.

While recognizing the potential value of the true-up mechanism, parties have taken a cautious approach that allows the company and the commission to gain experience in implementing, monitoring, and evaluating the program. And, since the program is a pilot, program corrections or cessation will take place if it is found unsuccessful or if unintended consequences develop. From the commission's perspective, the company must demonstrate an "enhanced commitment" to energy efficiency investment resulting from implementation of the FCA, including making efficiency and load management programs widely available, supporting building code improvement activity, pursuing appliance standards, and expanding of DSM programs.

Despite the approval of the pilot, the commission staff raised a number of the technical issues related to the relationship between energy efficiency program implementation and the application of the true-up mechanism. Given that the success of the mechanism is being determined in part by how it affects the company's investment in energy efficiency, several issues were raised regarding how that commitment was to be measured and, specifically, how evidence of that commitment could be distinguished from factors affecting sales per customer unrelated to the company's energy efficiency efforts. The commission noted that FCA will require close monitoring, and the development of proper metrics to evaluate the company's performance remains an issue.

5.2.2 Case Study: New Jersey Gas Decoupling

A relatively novel decoupling mechanism has recently been approved in New Jersey. In late 2005, New Jersey Natural Gas (NJNG) and South Jersey Gas (SJG) jointly filed proposals with the New Jersey Board of Public Utilities to implement a CUA clause in a five-year pilot program. The CUA was proposed as a way to *"[s]eparate the companies' margin recoveries from throughput and to adjust margin recoveries for variances in customer usage, enabling the companies to aggressively promote conservation and energy efficiency by their customers"* (New Jersey BPU, 2006).

The companies, the New Jersey Utility Board Staff, and the Department of the Public Advocate reached a settlement agreement that was approved by the New Jersey Commission in October 2006. Through the settlement, the proposed CUA was modified and implemented on a three-year pilot basis and renamed as the Conservation Incentive Program (CIP). The CIP replaced the Weather Normalization Clause, which helped cover weather-related fluctuations. The CIP is an incentive-based program that:

- Requires the companies to implement shareholder-funded conservation programs designed to aid customers in reducing their costs of natural gas and to reduce each utility's peak winter and design day system demand.
- Requires the companies to reduce gas supply related costs.
- Allows the companies to recover from customers certain non-weather margin revenue losses limited to the level of gas supply cost savings achieved.

The companies are required to make annual CIP filings, based on seven months of actual data and five months of projected data, with a June 1 filing date. The filings are to document actual results, perform the required

CIP collection test, and propose the new CIP rate. Any variances from the annual filings will be trued up in the subsequent year. The board has reserved the right to review any aspect of the companies' programs, including, but not limited to, the sufficiency of program funding.

The CIP tariffs include ROE limitations on recoveries from customers for both the weather and non-weather-related components. In the case of South Jersey Gas, the ROE was set at the level of the company's most recent general rate case. The ROE for New Jersey Natural Gas was set at 10.5 percent (compared to its most recently authorized rate of 11.5 percent).

The most significant element of the CIP tariff is its requirement that, as a condition for decoupling, the utilities must reduce gas supply costs—the so-called Basic Gas Supply Service (BGSS) savings—such that consumers see no net change in costs.

The methodology employed to calculate the non-weather-related CIP surcharge, if any, is delineated in paragraph 33(a) of the stipulation. If the non-weather-related CIP recovery is less than or equal to the level of available gas cost savings, the amount will be eligible for recovery through the CIP tariffs. Any portion of the non-weather CIP value that exceeds the available gas cost savings will not be recovered in the current period, will be deferred up to three years, and will be subject to an eligibility test in the subsequent period. Deferred CIP surcharges may be recovered in a future period to the extent that available gas cost savings are available to offset the deferred amount. If the pilot is terminated after the initial period, any remaining deferred CIP surcharges will not be recovered. The value of any BGSS savings during one year in excess of the non-weather CIP value cannot be carried forward for use in future year calculations.

NJNG will provide $2 million for program costs and SJG will provide $400,000 for each year of the pilot program, all of which will come from shareholders. The companies are required to provide the full cost of the programs, even if the program costs exceed the budgeted levels.

In approving the stipulation, the commission concluded with the following:

> With the CIP and the possible recovery of non-weather-related margin losses, the utilities have represented that they will actively promote conservation and energy efficiency by their customers through programs funded by their shareholders. The programs are not to replicate existing CEP programs and are to include, among other things, customized customer communications and outreach built upon the utilities' relationships with their customers. While not replicating existing CEP programs, the CIP programs include initiatives that promote customers' use of CEP programs through consistent messaging with the CEP programs. At the same time, by limiting non-weather-related CIP recovery by gas supply cost reductions, in addition to an earnings cap, the CIP gives recognition to the nexus between reductions in long-term usage and reductions in gas supply capacity requirements. By limiting any non-weather CIP recovery to offsetting gas supply cost reductions, the CIP does not just provide the utilities with a mechanism for rate recovery but ensures that the CIP results in an appropriate, concomitant reduction in gas supply costs borne by customers. In this way, customers taking BGSS will not incur any overall net rate increases arising from non-weather related load losses.
>
> (New Jersey BPU, 2006)

New Jersey Resources (NJR) recently reported its experience with the CIP. NJNG, NJR's largest subsidiary, realized 6.6 percent increase in its first-quarter earnings over last year due primarily to the impact of the recently approved CIP. The company states in a recent press release that:

> [Our] conservation Incentive Program has performed as intended, and has resulted in lower gas costs for customers and improved financial results for our shareowners. This innovative program is another example of working in partnership with our regulators to help all our stakeholders.
>
> For the three months ended December 31, 2006, NJR earned $28.1 million, or $1.01 per basic share,

compared with $34.3 million, or $1.24 per basic share, last year. The decrease in earnings was due primarily to lower earnings at NJR's unregulated wholesale energy services subsidiary, NJR Energy Services (NJRES), partially offset by improved results at NJNG. NJNG earned $19.9 million in the quarter, compared with $18.7 million last year. The increase in earnings was due to the impact of the CIP and continued customer growth. Gross margin at NJNG included $11.3 million accrued for future collection from customers under the CIP.

Weather in the first fiscal quarter was 18.3 percent warmer than normal and 18.2 percent warmer than last year. "Normal" weather is based on 20-year average temperatures. As with the weather normalization clause which preceded it, the impact of weather is significantly offset by the recently approved CIP, which is designed to smooth out year-to-year fluctuations on both gross margin and customers' bills that may result from changing weather and usage patterns. Included in the CIP accrual was $8 million associated with the warmer-than-normal weather and $3.3 million associated with non-weather factors. However, customers will realize annual savings of $10.6 million in fixed cost reductions and commodity cost savings of approximately $15 million through the first fiscal quarter.

(NJR, 2007)

5.2.3 Case Study: Baltimore Gas and Electric

Baltimore Gas and Electric (BGE) has had a form of a revenue-per-customer decoupling mechanism in place since 1998 for its natural gas business. The Maryland PSC allowed BGE to implement a monthly adjustment mechanism that accounts for the effect of abnormal weather patterns on sales.

Commission Order 80460 describes Rider 8[8] as follows:

Rider 8 is a tariff provision that serves as a "weather/number of customers adjustment clause." That is, when the weather is warmer, Rider 8 will increase BGE's revenues because gas demand is lower than normal. However, when the weather is colder than normal and gas demand is high, Rider 8 decreases BGE's revenues.

(Maryland PSC, 2005)

The mechanism is implemented through the Tariff Rider 8 or Monthly Rate Adjustment. The following explains the mechanism.

- The delivery price for residential service and for general service is adjusted to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the change in the number of customers from the test year level.
- The change in revenues associated with the customer charge is the change in number of customers multiplied by the customer charge for the rate schedule.
- The change in revenues associated with throughput is the test year average use per customer multiplied by the net number of customers added since the like-month during the test year, and multiplying that product by the delivery price for the rate schedule.
- The change in revenues associated with customer charge and throughput is added to test year revenue to restate test year revenues for the month to include the revised values.
- Actual revenues collected for the month are compared to the restated test year revenues and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable delivery price.
- Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month.

5.2.4 Case Study: Questar Gas Conservation Enabling Tariff

On December 16, 2005, Questar Gas, the Division of Public Utilities, and Utah Clean Energy (UCE) filed an application seeking approval of a three-year (pilot) Conservation Enabling Tariff (CET) and DSM Pilot Program. On September 13, 2006, Questar Gas, the Division, UCE, and the committee filed the Settlement Stipulation. The settlement was approved by the commission in October 2006 (Utah PSC, 2006). The approval of the settlement put in place the CET (Questar Gas, n.d., Section 2.11, pages 2–17), which represents the authorized

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revenue-per-customer amount Questar is allowed to collect from General Service customer classes.

Questar's allowed revenue for a given month is equal to the allowed distribution non-gas (DNG) revenue per customer for that month multiplied by the actual number of customers. The difference between the actual billed General Services DNG revenue[9] and the allowed revenue for that month is the monthly accrual for that month. The formula to calculate the monthly accrual is shown below.

> allowed revenue (for each month) =
>
> allowed revenue per customer for that month × actual general services customers
>
> monthly accrual = allowed revenue – actual general services DNG revenue

The accrual could be positive or negative.

For illustrative purposes, Table 5-4 shows the currently allowed DNG revenue per customer for each month of 2007.

For the purpose of keeping track of over- or under-recovery amounts on a monthly basis, the CET Deferred Account (Account 191.9) was established. At least twice a year, Questar will file with the commission a request for approval for the amortization of the amount accumulated in this account subject to the above formula. The amortization will be over a year, and the impacted customer class volumetric DNG rates will be adjusted by a uniform percentage increase or decrease. The balance in the account is subject to 6 percent annual interest rate or carrying charge applied monthly (0.5 percent each month).

The settlement states that there would be a 1-year review of the CET mechanism, and a technical workshop would be held in April 2007 commencing the 1-year evaluation process. The parties submitted testimony either supporting the continuation of the current CET mechanism beyond its first year of implementation, offering modifications or alternatives, or supporting discontinuation of the mechanism on June 1, 2007.

Table 5-4. Questar Gas DNG Revenue per Customer per Month

Month	DNG Revenue per Customer
January	$42.45
February	$34.03
March	$26.42
April	$20.34
May	$13.28
June	$10.25
July	$10.03
August	$9.44
September	$10.83
October	$15.48
November	$26.47
December	$36.51

Source: Questar Gas, n.d.

In testimony[10] filed by Questar supporting the continuation of the CET, the company stated the following benefits of the mechanism:

- CET allows Questar to collect the commission-allowed DNG revenue. During the first year before energy efficiency programs were in place, usage per customer increased, and over $1.7 million was credited back to customers.
- CET allows Questar to aggressively promote energy efficiency, and in 2007 the company launched six energy efficiency programs with a budget of about $7 million.
- CET aligns the interests of Questar and regulators for the benefit of customers.

Questar believes that the CET has been working as expected during its first year of implementation. The Utah Committee of Consumer Services filed testimony[11] on June 1, 2007, urging the discontinuation of the CET. The primary reason driving this recommendation is the alleged sales risk shift to consumers with little or no offsetting benefits for ratepayers assuming those risks.

As of the writing of this white paper, the proceeding is still in process and the commission is expected to reach a decision by October of 2007.

5.3 Lost Revenue Recovery Mechanisms

Lost revenue recovery mechanisms[12] are designed to recover lost margins that result as sales fall below test year levels due to the success of energy efficiency programs. They differ from decoupling mechanisms in that they do not attempt to decouple revenues from sales, but rather try to isolate the amount of under-recovery of margin revenues due to the programs. Simply put, the margin loss resulting from reductions in sales through the implementation of a successful energy efficiency program is calculated as the product of program-induced sales reductions and the amount of margin allocated per therm or kilowatt-hour in a utility's most recent rate case. In this sense, the shortfall in revenue recovery is treated as a cost to be recovered.

Although the disincentive to invest in successful efficiency programs might be removed, lost revenue recovery mechanisms do not remove a utility's disincentive to promote/support other energy saving policies, such as building codes and appliance standards, or their incentive to see sales increase generally, since the utility still earns more profit with additional sales.

One of the most important characteristics of a lost revenue recovery mechanism is that actual savings achieved from a successful energy efficiency program must be estimated correctly. Overestimates of savings will enable a utility to over-collect, and underestimates lead to under-collection of revenue. Unfortunately, reliance on evaluation creates two complications:

- While at its most rigorous, program evaluation produces a statistically valid estimate of actual savings. Rigorous evaluation can be expensive and, in any case, will not always be recognized as such by all parties.
- Because evaluation can only occur after an action has occurred, a process built on evaluation is one with potentially significant lags built in. It is possible to conduct rolling or real-time evaluations, albeit at considerable cost. In its least defensible applications, such mechanisms are applied with little or no independent evaluation and verification.

Despite these issues, several states have implemented lost revenue recovery mechanisms in lieu of decoupling as a way to address this barrier. For example, in January 2007, the Indiana Utility Regulatory Commission granted Vectren South's application for approval of a DSM lost margin adjustment factor for electric service.[13] Order Nos. 39201 and 40322 accepted the utility's request for a lost margin tracking mechanism. Recovery is done on a customer class and cost causation basis. Vectren South's total demand-side-related lost margin to be recovered through rates during the period February to April 2007 was $577,591.[14]

Perceived advantages and disadvantages of the lost revenue recovery mechanism are summarized in Table 5-5.

5.3.1 Case Study: Kentucky Comprehensive Cost Recovery Mechanism[15]

Kentucky currently allows lost revenue recovery for both electric and gas DSM programs as part of a comprehensive hybrid cost recovery mechanism. Under Kentucky Revised Statute 278.190, Kentucky's Public Service Commission determines the reasonableness of DSM plans that include components for program cost recovery, lost revenue recovery, and utility incentives for cost-effectiveness. The cost recovery mechanism can be reviewed as part of a rate proceeding, or as part of a separate, limited proceeding.

The DSM Cost Recovery Mechanism currently in effect for Louisville Gas and Electric Company (LG&E) is composed of factors for DSM program cost recovery (DCR), DSM revenue from lost sales (DRLS), DSM incentive (DSMI), and DSM balance adjustment (DBA). The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Mechanism applies is adjusted by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

Table 5-5. Pros and Cons of Lost Revenue Recovery Mechanisms

Pros
• Removes disincentive to energy efficiency investment in approved programs caused by under-recovery of allowed revenues. • May be more acceptable to parties uncomfortable with decoupling.
Cons
• Does not remove the throughput incentive to increase sales. • Does not remove the disincentive to support other energy saving policies. • Can be complex to implement given the need for precise evaluation, and will increase regulatory costs if it is closely monitored. • Proper recovery (no over- or under-recovery) depends on precise evaluation of program savings

DSMRC = DCR + DRLS + DSMI + DBA

The DCR includes all expected costs approved by the commission for each 12-month period for DSM programs, including costs for planning, developing, implementing, monitoring, and evaluating DSM programs. Only those customer classes to which the programs are offered are subject to the DCR. The cost of approved programs is divided by the expected kilowatt-hour sales for the next 12-month period to determine the DCR for a given rate class.

- For each upcoming 12-month period, the estimated reduction in customer usage (in kilowatt-hours) as determined for the approved programs shall be multiplied by the nonvariable revenue requirement per kilowatt-hour for purposes of determining the lost revenue to be recovered hereunder from each customer class.
- The nonvariable revenue requirement for the Residential and General Service customer class is defined as the weighted average price per kilowatt-hour of expected billings under the energy charges contained in the rate RS, VFD, RPM, and General Services rate schedules in the upcoming 12-month period, after deducting the variable costs included in such energy charges.
- The nonvariable revenue requirement for each of the customer classes that are billed under demand and energy rates (rates STOD, LC, LC-TOD, LP, and LP TOD) is defined as the weighted average price per kilowatt-hour represented by the composite of the expected billings under the respective demand and energy charges in the upcoming 12-month period, after deducting the variable costs included in the energy charges.
- The lost revenues for each customer class shall then be divided by the estimated class sales (in kilowatt-hour) for the upcoming 12-month period to determine the applicable DRLS surcharge.
- Recovery of revenue from lost sales calculated for a 12-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first.
- Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.
- Revenues collected under the mechanism are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming 12-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder, and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for, shall be reconciled in future billings under the DBA component.

DSMI is calculated by multiplying the net resource savings expected from the approved programs expected to be installed during the next 12-month period by 15 percent, not to exceed 5 percent of program expenditures. Net resource savings are equal to program benefits minus utility program costs and participant costs. Program benefits are calculated based on the present value of LG&E's avoided costs over the expected program life and includes capacity and energy savings.

The DBA is calculated for each calendar year and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, and previous application of the DBA. The balance adjustment (BA) amounts include interest applied to the bill amount calculated as the average of the "3-month commercial paper rate" for the immediately preceding 12-month period. The total of the BA amounts is divided by the expected kilowatt-hour sales to determine the DBA for each rate class. DBA amounts are assigned to the rate classes with under- or over-recoveries of DSM amounts.

The levels of the various DSM cost recovery components effective April 3, 2007, for LG&E's residential customers are shown in the Table 5-6.

5.4 Alternative Rate Structures

The lost margin issue arises because some or all of a utility's current fixed costs are recovered through volumetric charges. The most straightforward resolution to the issue is to design and implement rate structures that allocate a larger share of fixed costs to customer fixed charges. SFV rate structures allocate all current fixed costs to a per customer charge that does not vary with consumption. Alternatives to the SFV design employ a consumption block structure, which allocates costs across several blocks of commodity consumption and typically places most or all of the fixed costs within the initial block. This block is designed such that most customers will always consume more than this amount and, therefore, fixed costs will be recovered regardless of the level of sales in higher blocks (American Gas Association, 2006b). This produces a declining block rate structure.

Table 5-6. Louisville Gas and Electric Company DSM Cost Recovery Rates

DSM cost recovery component (DCR)	0.085 ¢/kilowatt-hour
DSM revenues from lost sales (DRLS)	0.005 ¢/kilowatt-hour
DSM incentive (DSMI)	0.004 ¢/kilowatt-hour
DSM balance adjustment (DBA)	(0.010)¢/kilowatt-hour
DSMRC rates	0.084 ¢/kilowatt-hour

Source: LG&E, 2004.

Such a rate design provides significant earnings stability for the utility in the short run, making it indifferent from a net revenue perspective to the customer's usage at any time. In this way, these alternative rate structures are similar to revenue decoupling; a utility has neither a disincentive to promote energy efficiency nor an incentive to promote increased sales. SFV and similar rate designs also are viewed by some as adhering more closely to a theoretically correct approach to cost allocation that sees fixed costs as a function of the number of customers or the level of customer demand.

This approach is most commonly discussed in the context of natural gas distribution companies, where fixed costs represent the costs to build out and maintain a distribution system. These costs tend to vary more as a function of the number of customers than of system throughput (American Gas Association, 2006c).[16] These alternative rate designs are more problematic when applied to integrated electric utilities, because fixed costs are in some cases related to the volume of electricity consumed. For example, the need for baseload capacity is driven by the level of energy consumption as much or more than by the level of peak demand. Practically, it is more difficult to allocate all fixed costs to a fixed customer charge, simply because such costs can be very

Table 5-7. Pros and Cons of Alternative Rate Structures

Pros
• Removes the utility's incentive to promote increased sales. • May align better with principles of cost-causation.
Cons
• May not align with cost causation principles for integrated utilities, especially in the long run. • Can create issues of income equity. • Movement to a SFV design can significantly reduce customer incentives to reduce consumption by lowering variable charges (applies more to electric than gas utilities).

high, and allocation to a fixed charge would impose serious ability-to-pay issues on lower income customers. Nevertheless, improvements in rate structures that better align energy charges with the marginal costs of energy will help reduce the throughput disincentive.

Given the overarching objective of capturing the net economic and environmental benefits of energy efficiency investments, SFV designs can significantly reduce a customer's incentive to undertake efficiency improvements because of the associated reduction in variable charges.

5.5 Notes

1. Also known as lost revenue or lost margin recovery.
2. The National Action Plan for Energy Efficiency.
3. Also see Chapter 6, "Utility Planning and Incentive Structures," in the *EPA Clean Energy-Environment Guide to Action.*
4. The Idaho Public Utilities Commission adopted a three-year decoupling pilot in March 2007, and in April 2007, the New York Public Service Commission ordered electric and natural gas utilities to file decoupling plans within the context of ongoing and new rate cases. The Minnesota legislature recently (spring 2007) enacted legislation authorizing decoupling. List of states is taken from the Natural Resources Defense Council's map of *Gas and Electric Decoupling in the US, June 2007.*
5. The design of the decoupling mechanism can address risk-shifting through the nature of the adjustments that are included. Some states have explicitly not included weather-related fluctuations in the decoupling mechanism (the utility continues to bear weather risk). In addition, recognizing that utility shareholder risk decreases with decoupling, some decoupling plans include provisions for capturing some of the risk reduction benefits for consumers. For example, PEPCO proposed (and subsequently withdrew a proposal for a 0.25 percent reduction in its ROE to reflect lower risk. The issue is under consideration by the Delaware Commission in a generic decoupling proceeding. The Oregon Public Utilities Commission reduced the threshold above which Cascade Natural Gas must share earnings from baseline ROE plus 300 basis points, to baseline ROE plus 175 basis points.
6. The impact of decoupling in eliminating the throughput incentives is lessened as the scope of the decoupling mechanism shrinks.
7. Note, however, that as the various determinants of sales, such as weather and economic activity, are excluded from the mechanism, the need for complex adjustment and evaluation methods increases. In any case, an evaluation process should nevertheless be part of the broader energy efficiency investment process.
8. <www.bge.com/vcmfiles/BGE/Files/Rates%20and%20Tariffs/Gas%20Service%2 Tariff/Brdr_3.doc>.
9. Customers' bills include a real-time, customer-specific Weather Normalization Adjustment (see Section 2.08 of Questar Gas, n.d.) to eliminate the impact of warmer or colder than normal weather on the DNG portion of the bill.
10. Direct Testimony of Barrie L. McKay to Support the Continuation of the Conservation Enabling Tariff for Questar Gas Company, Docket No. 05-057-T01, June 1, 2007, accessed at <www.psc.utah.gov/gas/05docs/05057T01/535586-1-07DitTestBarrieMcKay.doc>.
11. Direct Testimony of David E. Dismukes, Ph.D., on Behalf of the Utah Committee of Consumer Services, Docket No. 05-057-T01, June 1, 2007, accessed at <www.psc.utah.gov/gas/05docs/05057T01/6-1-0753584DirTestDavidDismukesPh.D.doc>.

12. Also known as lost revenue or lost margin recovery mechanisms.

13. Order issued in Cause No. 39453 DSM 59 on January 31, 2007, accessed at <www.in.gov/iurc/portal/Modules/Ecms/Cases/Docketed_Cases/ViewDocumentaspx?DocID=0900b631800c5033>.

14. Energy efficiency traditionally has been defined as an overall reduction in energy use due to use of more efficiency equipment and practices, while load management, as a subset of demand response has been defined as reductions or shifts in demand with minor declines and sometimes increases in energy use.

15. This description quotes extensively from LG&E, 2004.

16. Even in a gas distribution system, fixed costs do vary partly as a function of individual customer demand. The SFV rate used by Atlanta Gas Light, for example, estimates the fixed charge as a function of the maximum daily demand for gas imposed by each premise.

6: Performance Incentives

This chapter provides a practical overview of alternative performance incentive mechanisms and presents their pros and cons. Detailed case studies are provided for each mechanism.

6.1 Overview

The final financial effect is represented by incentives provided to utility shareholders for the performance of a utility's energy efficiency programs. Even if regulatory policy enables recovery of program costs and addresses the issue of lost margins, at best, two major disincentives to promotion of energy efficiency are removed. Financially, demand- and supply-side investments are still not equivalent, as the supply-side investment will generate greater earnings. However, the availability of performance incentives can establish financial equivalence and creates a clear utility financial interest in the success of efficiency programs.

Three major types of performance mechanisms have been most prevalent:

- Performance target incentives
- Shared savings incentives
- Rate of return incentives

Table 6-1 illustrates the various forms of performance incentives in effect today.

Table 6-1. Examples of Utility Performance Incentive Mechanisms

State	Type of Utility Performance Incentive Mechanism	Details
AZ	Shared savings	Share of net economic benefits up to 10 percent of total DSM spending.
CT	Performance target Savings and other programs goals	Management fee of 1 to 8 percent of program costs (before tax) for meeting or exceeding predetermined targets. One percent incentive is given to meet at least 70 percent of the target, 5 percent for meeting the target, and 8 percent for 130 percent of the target.
GA	Shared savings	15 percent of the net benefits of the Power Credit Single Family Home program.
HI	Shared savings	Hawaiian Electric must meet four energy efficiency targets to be eligible for incentives calculated based on net system benefits up to 5 percent.

Table 6-1. Examples of Utility Performance Incentive Mechanisms (continued)

State	Type of Utility Performance Incentive Mechanism	Details
IN	Shared savings/rate of return (utility-specific)	Southern Indiana Gas and Electric Company may earn up to 2 percent added ROE on its DSM investments if performance targets are met with one percent penalty otherwise.
KS	Rate of return incentives	2 percent additional ROE for energy efficiency investments possible.
MA	Performance target Multi-factor performance targets, savings, value, and performance	5 percent of program costs are given to the distribution utilities if savings targets are met on a program-by-program basis.
MN	Shared savings Energy savings goal	Specific share of net benefits based on cost-effectiveness test is given back to the utilities. At 150 percent of savings target, 30 percent of the conservation expenditure budget can be earned.
MT	Rate of return incentives	2 percent added ROE on capitalized demand response programs possible.
NV	Rate of return incentives	5 percent additional ROE for energy efficiency investments.
NH	Shared savings Savings and cost- effectiveness goals	Performance incentive of up to 8 to 12 percent of total program budgets for meeting cost-effectiveness and savings goals.
RI	Performance targets Savings and cost- effectiveness goals	Five performance-based metrics and savings targets by sector. Incentives from at least 60 percent of savings target up to 125 percent.
SC	N/A	Utility-specific incentives for DSM programs allowed.

Notes: For AZ, CT, MA, MN, NV, NH, and RI, see Kushler, York, and Witte, 2006.

For IN, KS, and SC, see Michigan PUC, 2003.

For HI, see Hawaii PUC, 2007. Note that in a prior order the Hawaii Commission eliminated specific shareholder incentives and fixed-cost recovery. However, in the instant case, the commission was persuaded to provide a shared savings incentive.

Vermont uses an efficiency utility, Efficiency Vermont, to administer energy efficiency programs. While not a utility in a conventional sense, Efficiency Vermont is eligible to receive performance incentives.

6.2 Performance Targets

Mechanisms that allow utilities to capture some portion of net benefits typically include savings performance targets. Incentives are not paid unless a utility achieves some minimum fraction of proposed savings, and incentives are capped at some level above projected savings.[1] Several states have designed multi-objective performance mechanisms. Utilities in Connecticut, for example, are eligible for "performance management fees" tied to performance goals such as lifetime energy savings, demand savings, and other measures. Incentives are available for a range of outcomes from 70 to 130 percent of pre-determined goals. A utility is not entitled to the management fee unless it achieves at least 70 percent of the targets. After 130 percent of the goals have been reached, no added incentive is provided. Over the incentive-eligible range of 70 to 130 percent, the utilities can earn 2 to 8 percent of total energy efficiency program expenditures.

6.2.1 Case Study: Massachusetts

The Massachusetts Department of Telecommunications and Energy Order in Docket 98-100 (February 2000)[2] allows for performance-based performance incentives where a distribution company achieves its "design" performance level (i.e., the energy efficiency program performance level that the distribution company expects to achieve). The performance tiers are defined as follows:

1. The design performance level represents the level of performance that the distribution utility expects to achieve from the implementation of the energy efficiency programs included in its proposed plan. The design performance level is expressed in terms of levels of savings in energy, commodity, and capacity, and in other measures of performance as appropriate.

2. The threshold performance level (the minimum level that must be achieved for a utility to be eligible for an incentive) represents 75 percent of the utility's design performance level.

3. The exemplary performance level represents 125 percent of the utility's design performance level.

For the distribution utilities that achieve their design performance levels, the after-tax performance incentive is calculated as the product of:[3]

1. The average yield of the 3-month United States Treasury bill calculated as the arithmetic average of the yields of the 3-month United States Treasury bills issued during the most recent 12-month period, or as the arithmetic average of the 3-month United States Treasury bill's 12-month high and 12-month low, and

2. The direct program implementation costs.

A distribution utility calculates its after-tax performance incentive as the product of:

1. The percentage of the design performance level achieved, and

2. The design performance incentive level, provided that the utility will earn no incentive if its actual performance is below its threshold performance level, and will earn no more than its exemplary performance level incentive even if its actual performance is beyond its exemplary performance level.

In May 2007, the Massachusetts Department of Public Utilities issued an order approving NSTAR Electric's Energy Efficiency Plan for calendar year 2006, filed with the department in April 2006.[4] NSTAR Electric's utility performance incentive proposal contains performance categories based on savings, value, and performance determinants and allocates specific weights to each category. For its residential programs, NSTAR Electric allocates the weights for its savings, value, and performance determinants as follows: 45 percent, 35 percent, and 20 percent, respectively. For its low-income programs, the weights are 30 percent, 10 percent, and 60 percent, respectively. And for its commercial and industrial programs, NSTAR sets the weights at 45 percent, 35 percent, and 20 percent, respectively.[5]

NSTAR proposed an incentive rate equal to 5 percent (after tax) of net benefits, as opposed to the pre-approved

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3-Month Treasury rate, and also requested that the exemplary performance level be set at 110 percent of design level for 2006 rather than the 125 percent threshold set by the department. The department accepted both changes. With regard to the latter, the department noted that the precision of performance measurements had improved to the point that performance could be forecast more accurately. Based on these parameters, the company estimated its annual incentive would be $2.4 million.[6]

6.3 Shared Savings

With a shared savings mechanism, utilities share the net benefits resulting from successful implementation of energy efficiency programs with ratepayers. Implicitly, net benefits are tied to the utility's avoided costs, as these costs determine the level of economic benefit achieved. Therefore, the potential upside to a utility from use of a shared savings mechanism will be greater in jurisdictions with higher avoided costs.[7] Key elements in fashioning a shared savings mechanism include:

- The degree of sharing (the percentage of net benefits retained by a utility).
- The amount to be shared (maximum dollar amount of the incentive irrespective of the sharing percentage).
- The extent to which there are penalties for failing to reach performance targets.
- The manner in which avoided costs are determined for purposes of calculating net benefits.
- The threshold values above which the sharing will begin.

6.3.1 Case Study: Minnesota

Minnesota Statute § 216B.241[8] requires Minnesota's energy utilities to invest in energy conservation improvement programs (CIP) authorized by the Minnesota Department of Commerce. Utilities are allowed to recover their costs annually. Part of the CIP cost recovery is achieved through a conservation cost recovery charge (CCRC). If a utility's CIP costs differ from the amount recovered through the CCRC, the utility can adjust its rates annually through the conservation cost recovery adjustment (CCRA). Utilities record CIP costs in a "tracker" account. The Minnesota Public Utilities Commission reviews these accounts before the utilities are authorized to make adjustments to their rates. The statute also authorizes the commission to provide an incentive rate of return, a shared savings incentive, and lost margin/fixed cost recovery.

The legislation describes the requirements of an incentive plan as follows:

> Subd. 6c. Incentive plan for energy conservation improvement.
>
> (a) The commission may order public utilities to develop and submit for commission approval incentive plans that describe the method of recovery and accounting for utility conservation expenditures and savings. In developing the incentive plans the commission shall ensure the effective involvement of interested parties.
>
> (b) In approving incentive plans, the commission shall consider:
>
> (1) Whether the plan is likely to increase utility investment in cost-effective energy conservation.
>
> (2) Whether the plan is compatible with the interest of utility ratepayers and other interested parties.
>
> (3) Whether the plan links the incentive to the utility's performance in achieving cost-effective conservation.
>
> (4) Whether the plan is in conflict with other provisions of this chapter.

As explained in the Order Approving DSM Financial Incentive Plans under Docket E, G-999/CI-98-1759,[9] issued in April 2000, Minnesota Public Utilities Commission convened a round table in December 1998 to assess gas and electric DSM efforts *"to identify other DSM programs and methodologies that effectively conserve energy, to revaluate the need for gas and electric DSM financial incentives and make recommendations for elimination or redesign."*

In November 1999, a joint proposal for a shared savings DSM financial incentive plan was filed with the commission. In the same month, each of the utilities filed their proposed DSMI plans for 1999 and beyond.

The jointly proposed DSM financial incentive plan, which formed the basis for individual utility plans, was intended to replace the then current incentive plans. A primary characteristic of the proposed plan was the method for determining a utility's target energy savings used to calculate incentives. Each utility was subject to the same following formula in determining the energy savings goal:

(approved energy savings goal ÷ approved budget) × statutory minimum spending level

where the statutory spending requirement is 1 percent for electric IOUs (Xcel at 2 percent) and 0.5 percent for gas utilities.

The utilities were required to show that their expenditures resulted in net ratepayer benefits (utility program costs netted against avoided supply-side costs). The net benefits of achieving the specific percentage of energy savings goals were calculated by determining the utilities' avoided costs resulting from their actual CIP achievement, then subtracting the CIP costs. A portion of these benefits was given to the shareholders as an incentive. The size of the incentive depended on the percentage of the net benefits achieved. This percentage increased as the percentage of the goal reached increased. At 90 percent of the goal, the utility received no incentive. At 91 percent of the goal, a small percentage of its net benefits were given to the utility. Net benefits, as mentioned, depended on the utility's avoided costs, which varied from utility to utility. In order to treat all utilities equally, the percentage values were calculated such that at 150 percent of the goals, the utility's incentive was capped at 30 percent of its statutory spending requirement.

In the April 7, 2000 order, the commission found that the plan was likely to increase investment in cost-effective energy conservation. The incentive grew for each incremental block of energy savings. No significant incentive was provided unless a utility met or exceeded its expected energy savings at minimum spending requirements.[10] The mechanism was designed such that if a utility's program was not cost-effective (i.e., there were no net benefits), no incentives were paid. As the cost-effectiveness increased, net benefits and incentives increased accordingly.

The utilities make compliance filings on February 1 of each year to demonstrate the application of the incentive mechanism to a utility's budget and energy savings target.

The 2007 compliance filing[11] of Northern States Power Company (NSP), a wholly owned subsidiary of Xcel Energy, offers useful insight into application of the electric and gas incentive mechanism, in this case incorporating goals and budgets approved in November 2006. Table 6-2 shows the basic calculation of net benefits, and Table 6-3 shows the incentive amount earned by NSP at different levels of program savings.

6.3.2 Case Study: Hawaiian Electric Company (HECO)

In Order No. 23258, the Hawaii Public Utilities Commission approved HECO's proposed energy efficiency incentive mechanism. The order sets four energy efficiency goals that HECO must meet before being entitled to any incentive based on net system benefits (less program costs). Only positive incentives are allowed; in other words, once HECO meets and exceeds the energy efficiency goals, it is entitled to the incentive, but if it cannot achieve the goal, no penalties will apply.

The order details the approach as follows:

> The DSM Utility Incentive Mechanism will be calculated based on net system benefits (less program costs), limited to no more than the utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side rate based investments, capped at $4 million, subject to the following performance requirements and incentive schedule. As indicated in section III.E.l.c., supra, the commission is not requiring negative incentives. In order to encourage high achievement, HECO must meet or exceed the megawatt-hour and megawatt Energy Efficiency goals for both the

Table 6-2. Northern States Power Net Benefit Calculation

2007 Inputs	Electric	Gas
Approved CIP energy (kWh/MCF)	238,213,749	729,086
Approved CIP budget ($)	45,504,799	5,239,557
Minimum spending[a] ($)	42,147,472	3,718,065
Energy savings @ 100% of goal[b] (kWh/MCF)	220,638,428	517,370
Estimated net benefits[c] ($)	180,402,782	65,813,455
Net benefits @ 100% of goal[d] ($)	167,092,732	46,702,175

(a) Statutory requirement. Electric: 2 percent of gross operating revenue. Gas: 0.5 percent.

(b) Energy savings at 100 percent of goal: (Minimum Spending × Goal Energy Savings) ÷ Goal Spending.

(c) Estimated net benefits are calculated from the approved cost-benefit analysis in the 2007/2008/2009 CIP Triennial Plan. For electric, estimated net benefits are equal to the sum of each program's total avoided costs minus spending. For gas, the estimated net benefit is equal to total gas CIP revenue requirements test NPV for 2007 as first and only year.

(d) Net benefits at 100 percent of goal = (Minimum Spending × Goal Net Benefits) ÷ Goal Spending.

Table 6-3. Northern States Power 2007 Electric Incentive Calculation

Electric	Kilowatt-Hour	Percent of Base	Estimated Benefits Achieved	Estimated Incentive
90% of goal	198,574,585	0.00%	150,383,459	0
100% of goal	220,638,428	0.8408%	167,092,732	1,404,916
110% of goal	242,702,270	1.6816%	183,802,005	3,090,815
120% of goal	264,766,113	2.5224%	200,511,278	5,057,697
130% of goal	286,829,956	3.3632%	217,220,552	7,305,562
140% of goal	308,893,799	4.2040%	233,929,825	9,834,410
150% of goal	330,957,641	5.0448%	250,639,098	12,644,241

Source: Xcel Energy, 2006.

commercial and industrial sector, and the residential sector, established in section III.A., supra, for HECO to be eligible for a DSM utility incentive. If HECO fails to meet one or more of its four Energy Efficiency goals, see supra section III.A.8., HECO will not be eligible to receive a DSM utility incentive. Upon a determination that HECO is eligible for a DSM utility incentive, the next step will be to calculate the percentage by which HECO's actual performance meets or exceeds each of its Energy Efficiency goals. Then, these four percentages will be averaged to determine HECO's "Averaged Actual Performance Above Goals."

(Hawaii PUC, 2007)

The incentive allowed HECO (as a percentage of net benefits) is a function of the extent to which the company exceeds its savings goals, as illustrated by Table 6-4.

The commission also provided the following example to illustrate how the mechanism works.

Assume that HECO's 2007 actual total gross commercial and industrial energy savings is 100,893 megawatt-hours, HECO's 2007 actual total gross residential energy savings is 50,553 megawatt-hours, HECO's 2007 actual total gross commercial and industrial demand savings is 13.416 megawatts, and HECO's 2007 actual total gross residential energy savings is 14.016 megawatts.

(Hawaii PUC, 2007)

Table 6-4. Hawaiian Electric Company Shared Savings Incentive Structure

Averaged Actual Performance Above Goals	DSM Utility Incentive (% of Net System Benefits)
Meets goal	1%
Exceeds goal by 2.5%	2%
Exceeds goal by 5%	3%
Exceeds goal by 7.5%	4%
Exceeds goal by 10.0% or more	5%

Source: Hawaii PUC, 2007.

6.3.3 Case Study: The California Utilities

In September 2007, CPUC adopted a far-reaching utility performance incentives plan that creates both the potential for significant additions to utility earnings for superior performance, and significant penalties for inadequate performance.

Under the plan, shareholder incentives are tied to utilities' independently verified achievement of CPUC-established savings goals for each three-year program cycle *and* to the level of verified net benefits. Savings goals have been established for kilowatt-hours, kilowatts, and therms. To be eligible for an incentive, utilities must achieve at least 80 percent of each applicable savings goal.[12] If utilities achieve 85 percent and up to 100 percent of the simple average of all applicable goals, shareholders will receive a reward of 9 percent of verified net benefits.[13] Achievement of over 100 percent or more of the goal will yield a performance payment of 12 percent of verified net benefits, with a statewide cap of $450 million over each three-year program cycle. Failure to achieve at least 65 percent of goal will result in performance penalties. Penalties are calculated as the greater of a charge per unit (kilowatt-hour, kilowatt, or therm) for shortfalls at or below 65 percent of goal, or a dollar-for-dollar payback to ratepayers of any negative net benefits. Total penalties also are capped statewide at $500 million. A performance dead-band of between 65 percent and 85 percent of goal produces no performance reward or penalty. Figure 6-1 and Table 6-6 illustrate the incentive structure.

For example, if utilities achieve the threshold 85 percent of goal for the current 2006-2008 program period, and total verified net benefits equal the estimated value of $1.9 billion on a statewide basis, the utilities would

Table 6-5. Illustration of HECO Shared Savings Calculation

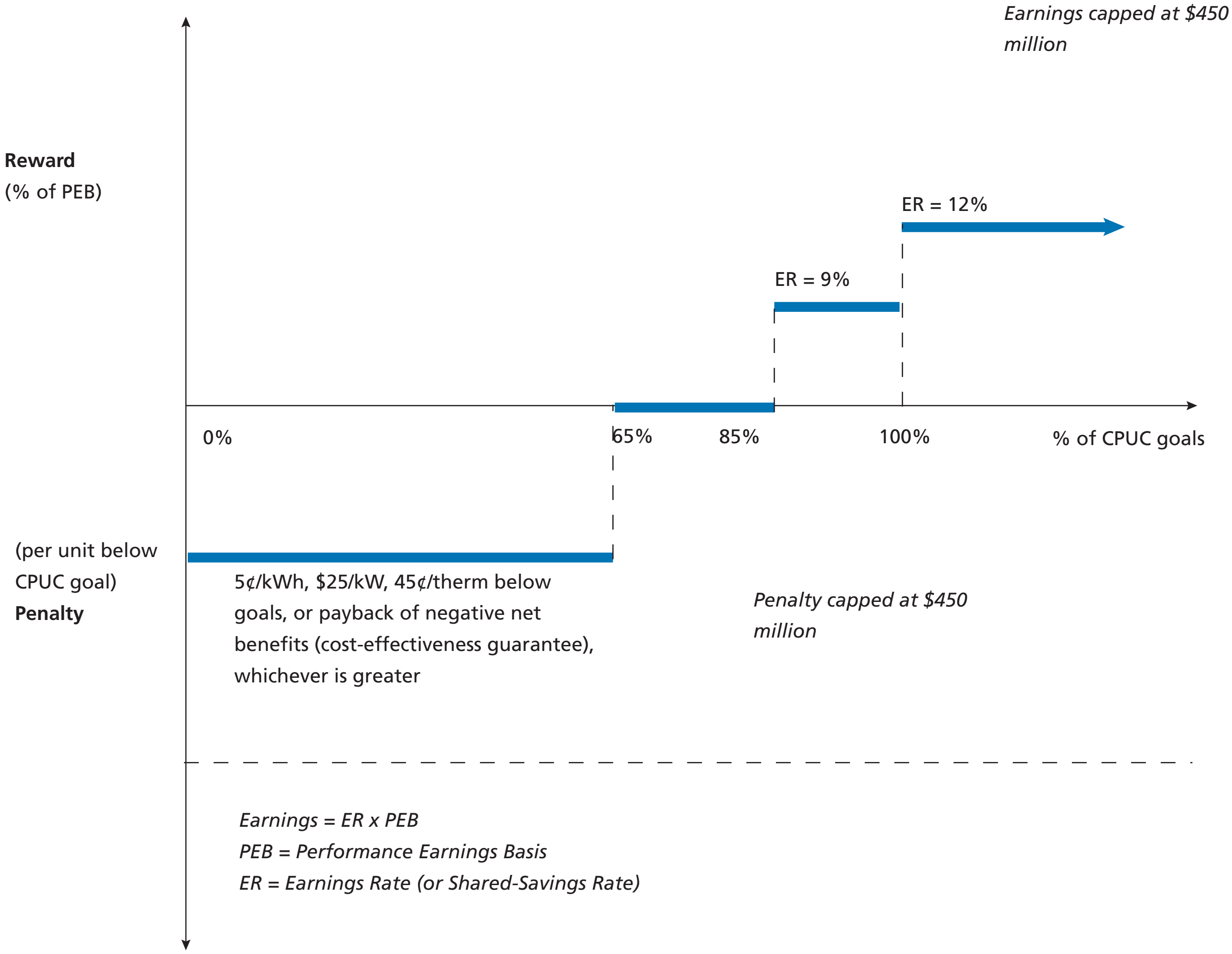
Energy Efficiency Energy Savings (MWh)	2007 Goal (MWh)	2007 Actual Performance (MWh)	Energy Efficiency Goal Met?	*Actual Performance Above 2007 Goal (%)*
Commercial and industrial				
Total gross energy savings	91,549	100,893	10.21%	Yes
Residential				
Total gross energy savings	50,553	50,553	Yes	0%
Commercial and industrial				
Total gross demand savings	13.041	13.416	Yes	*2.88%*
Residential				
Total gross demand savings	13.336	14.016	Yes	*5.10%*
Averaged actual performance above goals	4.55%			
DSM utility incentive (% of net system benefits)	2%			

Source: Hawaii PUC, 2007.

receive 9 percent of that amount, or $175 million. If the utilities each met 100 percent of the savings goals, and the estimated verified net benefit of $2.7 billion is realized, the earnings bonus would equal $323 million.

Rewards or penalties may be collected in three installments for each three-year program cycle. Two interim reward claims or penalty assessments will be made based on estimated performance and net benefits. The third payment—a "true-up claim"—will be made after the program cycle is complete and savings and net benefits have been independently verified. Thirty percent of each interim reward payment is withheld to cover potential errors in estimated earnings calculations. Verified savings will be based on independent measurement and evaluation studies managed by CPUC.

Figure 6-1. California Performance Incentive Mechanism Earnings/ Penalty Curve



Source: CPUC, 2007.

CPUC also adjusted the basic cost-effectiveness calculations for purposes of determining net benefits. The estimated value of the performance incentives must be treated as a cost in the net benefit calculation, both during the program planning process to determine the overall cost-effectiveness of the utilities' energy efficiency portfolios, and when the value of net benefits is calculated for purposes of reward determinations subsequent to program implementation.

The commission devoted a significant portion of its order to the fundamental issues surrounding utility performance incentives—whether and why a utility should earn rewards for what are essential expenditures of ratepayer funds; the basis for determining the magnitude of the shareholder rewards; and the relationship between relative reward levels and performance. CPUC ultimately concluded that incentives were appropriate and necessary to achieve the ambitious energy efficiency goals the utilities had been given. The rewards at high levels of goal attainment were set to be generally reflective of earnings from supply-side investments foregone due to implementation of the energy efficiency programs.

Table 6-6. Ratepayer and Shareholder Benefits Under California's Shareholder Incentive Mechanism (Based on 2006–2008 Program Cycle Estimates)

Verified Savings % of Goals	Total Verified Net Benefits	Shareholder Earnings		Ratepayers' Savings
125%	$2,919	$450	cap	$3,469
120%	$3,673	$441		$3,232
115%	$3,427	$411		$3,016
110%	$3,181	$382		$2,799
105%	$2,935	$352		$2,583
100%	$2,689	$323		$2,366
95%	$2,443	$220		$2,223
90%	$2,197	$198		$1,999
85%	$1,951	$176		$1,775
80%	$1,705	$0		$1,705
75%	$1,459	$0		$1,459
70%	$1,213	$0		$1,213
65%	$967	($144)		$1,111
60%	$721	($168)		$889
55%	$475	($199)		$674
50%	$228	($239)		$467
45%	($18)	($276)		$258
40%	($264)	($378)		$114
35%	($510)	($450)	cap	($60)

Source: CPUC, 2007.

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Finally, the structure of what the commission termed the "earnings curve," showing the relationship between goal achievement and reward and penalty levels, was fashioned to achieve a reasonable balance between opportunity for reward and risk for penalty. And although potential penalties are significant, even in cases in which programs deliver a net benefit (but fail to meet goal), CPUC found that utilities have sufficient ability to manage these risks, such that penalties can reasonably be associated with nonperformance as opposed to uncontrollable circumstances. This last point has been contested. Utilities are subject to substantial evaluation risk in the final true-up claim. An evaluator's finding that per-unit measure savings or net-to-gross ratios[14] were significantly lower than those estimated ex ante (thus significantly lowering system net benefits) could result in utilities having to refund interim performance payments, which are based on estimates of net benefits. While utilities have some control over net-to-gross ratios through program design, there is considerable debate over the reliability of net-to-gross calculations, and even if utilities attempt to monitor the level of free ridership in a program, the final findings of an independent evaluator are unpredictable.

6.4 Enhanced Rate of Return

Under the bonus rate of return mechanism, utilities are allowed an increased return on investment for energy efficiency investments or offered a bonus return on total equity investment for superior performance. A number of states allowed an increased rate of return on energy efficiency–related investments starting in the 1980s. In fact, the majority of the states that allowed or required ratebasing or capitalization also allowed an increased rate of return for such investments. For example, Washington and Montana allowed an additional 2 percent return for energy efficiency investments, while Wisconsin adopted a mechanism where each additional 125 MW of capacity saved with energy efficiency yielded an additional 1 percent ROE. Connecticut authorized a 1 to 5 percent additional return (Reid, 1988).

Although a bonus rate of return remains an option "on the books" in a number of states, it is seldom used, largely because capitalization of efficiency investments has fallen from favor. The most often-cited current example of a bonus return mechanism, and the only one applied to a utility with significant efficiency spending, is found in Nevada. The Nevada approach, described earlier, allows a bonus rate of return for DSM that is 5 percent higher than authorized rates of return for supply investments. The earlier discussion cited the concerns raised by some that this mechanism does not provide an incentive for superior performance.

6.5 Pros and Cons of Utility Performance Incentive Mechanisms

Shared savings and performance target incentive mechanisms are similar, in that both tie an incentive to achievement of some target level of performance. The two differ in the specific nature of the target and the base upon which the incentive is calculated. The application of each mechanism will differ based on regulators' decisions regarding the specific performance target levels; the relative share of incentive base available as an incentive; the maximum amount of the incentive; and whether performance penalties can be imposed (as opposed to simply failing to earn a performance incentive). Whether an incentive mechanism is implemented will depend on how regulators balance the value of the mechanism in incenting exemplary performance against the cost to ratepayers and arguments that customers should not have to pay for a utility that simply complies with statutory or regulatory mandates. A bonus rate of return mechanism also can include performance measures (those applied in the late 1980s and early 1990s often did), but may not, as in the Nevada example. Table 6-7 summarizes the major pros and cons of performance incentive mechanisms as a whole.

Table 6-7. Pros and Cons of Utility Performance Incentive Mechanisms

Pros
• Provide positive incentives for utility investment in energy efficiency programs. • Policy-makers can influence the types of program investments and the manner in which they are implemented through the design of specific performance features.
Cons
• Typically requires post-implementation evaluation, which entails the same issues as cited with respect to fixed-cost recovery mechanisms. • Mechanisms without performance targets can reward utilities simply for spending, as opposed to realizing savings. • Mechanisms without penalty provisions send mixed signals regarding the importance of performance. • Incentives will raise the total program costs borne by customers and reduce the net benefit that they otherwise would capture.

6.6 Notes

1. Performance targets can include metrics beyond energy and demand savings; installations of eligible equipment or market share achieved for certain products such as those bearing the ENERGY STAR™ label.

2. *Department of Telecommunications and Energy on Its Own Motion to Establish Methods and Procedures to Evaluate and Approve Energy Efficiency Programs, Pursuant to G.L. c. 25, § 19 and c. 25A, § 11G,* found at, <www.mass.gov/Eoca/docs/dte/electric/98-100/finalguidelinesorder.pdf>.

3. The following is quoted from Investigation by the Department of Telecommunications and Energy on its own motion to establish methods and procedures to evaluate and approve energy efficiency programs, pursuant to G.L. c. 25, § 19 and c. 25A, § 11G, found at <www.mass.gov/Eoca/docs/dte/electric/98-100/finalguidelinesorder.pdf>.

4. *Final Order in D.T.E./D.P.U Docket 06-45, Petition of Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, d/b/a NSTAR Electric, Pursuant to G.L. c. 25, § 19 and G.L. c. 25A, § 11G, for Approval of Its 2006 Energy Efficiency Plan.* Found at <www.mass.gov/Eoca/docs/dte/electric/06-45/5807dpuorder.pdf>.

5. Ibid, page 9.

6. Ibid, page 10.

7. Avoided costs are the costs that would otherwise be incurred by a utility to serve the load that is avoided due to an energy efficiency program. Historically, these costs were determined administratively according to specified procedures approved by regulators. This is still the predominant approach, although some jurisdictions now use wholesale market costs to represent avoided costs. This Report will not address the derivation of these costs in detail, but note that the level of avoided costs is extremely important in determining energy efficiency program cost-effectiveness and can be the subject of substantial debate.

8. Minnesota Statute 216B.241, 2006, found at <www.revisor.leg.state.mn.us/bin/getpub.php?type=s&year=current&num=216B.241>.

9. *Order Approving Demand-Side Management Financial Incentive Plans,* Docket No. E,G-999/CI-98-1759, April 7, 2000, accessed at <https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=822257>.

10. Ibid, page 16.

11. *Xcel Energy Compliance Filing 2007 Electric and Gas CIP Incentive Mechanisms,* Docket E,G-999/CI-98-1759, February 1, 2007, accessed at <https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3761385>.

12. PG&E and SDG&E must meet therm, kilowatt-hour, and kilowatt goals; SCE must meet kilowatt-hour and kilowatt goals; and Southern California Gas faces only a therm goal.

13. Southern California Gas need only meet the 80 percent minimum therm savings threshold to be eligible for an incentive.

14. The net-to-gross ratio is a measurement of program free ridership. Free riders are program participants who would have taken the program's intended action, even in the absence of the program.

7: Emerging Models

This chapter examines two new models currently being explored to address the basic financial effects associated with utility energy efficiency investment. The first model has been proposed as an alternative comprehensive cost recovery and performance incentive mechanism. The second represents a fundamentally different approach to funding energy efficiency within a utility resource planning and procurement framework.

7.1 Introduction

Although the details of the policies and mechanisms described above for addressing the three financial effects continue to evolve in jurisdictions across the country, the basic classes of mechanisms have been understood, applied, and debated for more than two decades. Most jurisdictions currently considering policies to remove financial disincentives to utility investment in energy efficiency are considering one or more of the mechanisms described earlier. However, new models that do not fit easily within the traditional classes of mechanisms are now being considered.

7.2 Duke Energy's Proposed Save-a-Watt Model

The persistent and sometimes acrimonious nature of the debate over the proper approach to removing disincentives, combined with a sense that the energy efficiency investment environment is on the threshold of fundamental change, has led some to search for a new way to address the investment disincentive. Although no approach has yet been adopted, an intriguing proposal has emerged from Duke Energy in an energy efficiency proceeding in North Carolina.[1] Duke's energy efficiency investment plan includes an energy efficiency rider that encapsulates program cost recovery, recovery of lost margins, and shareholder incentives into one conceptually simple mechanism keyed to the utility's avoided cost. The approach is an attempt to improve upon previous methods with a more streamlined and comprehensive mechanism.

The energy efficiency rider supporting Duke's proposal is based on the notion that if energy efficiency is to be viewed from the utility's perspective as equivalent to a supply resource, the utility should be compensated for its investment in energy efficiency by an amount roughly equal to what it would otherwise spend to build the new capacity that is to be avoided. Thus, the Duke proposal would authorize the company "to recover the amortization of and a return on 90% of the costs avoided by producing save-a-watts" (Duke Energy, 2007, p. 2). There is no explicit program cost recovery mechanism, no lost margin recovery mechanism and no shareholder incentive mechanism—all such costs and incentives would be recovered under the 90 percent of avoided cost plan. According to Duke, this structure creates an explicit incentive to design and deliver programs efficiently, as doing so will minimize the program costs and maximize the financial incentive received by the company. This mechanism would apply to the full Duke demand-side portfolio, including demand-response programs.

The Duke proposal includes one element that is often not addressed explicitly in other cost recovery and incentive mechanisms, but has significant implications. A number of states have, for a variety of reasons, excluded demand response from incentive mechanisms. This becomes an issue insofar as demand response programs

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typically cost considerably less on a per-kilowatt basis than energy efficiency, and thus could yield substantial margins for the company under a cost recovery and incentive mechanism that pays on the basis of avoided cost. Currently available information on the proposal does not provide a basis for evaluating how significant an issue this might be (e.g., what portion of the total portfolio's impacts is due to demand response programs contained therein).

The proposed rider is to be implemented with a balancing mechanism, including annual adjustments for changes in avoided costs going forward, and to ensure that the company is compensated only for actual energy and capacity savings as determined by ex post evaluation. However, the rider is set initially based on the company's estimate of savings, and the company acknowledges that meaningful evaluation cannot occur until implementation has been underway for some time. For example, at least one year's worth of program data is required to enable valid samples to be drawn. Drawing the samples, performing data collection, and conducting analysis and report preparation can then take another six months or more. Duke's filing suggests that true-up results may lag by about three years (Duke Energy, 2007, note 4, p. 12).

The basic mechanics of the energy efficiency rider are as follows. The calculations are performed by customer class, consistent with many recovery mechanisms that, for equity reasons, allocate costs to the classes that benefit directly from the investments. The nomenclature for the class allocation has been omitted here for simplicity.

$$\mathbf{EEA = (AC + BA) \div sales}$$

Where:

EEA = Energy efficiency adjustment, expressed in $/kWh

AC = Avoided cost revenue requirement

BA = Balance adjustment (true-up amount)

$$\mathbf{AC = (ACC + ACE) \times 0.90}$$

Where:

ACC = Avoided capacity cost revenue requirement

AEC = Avoided energy cost revenue requirement

$$\mathbf{ACC = DC + (ROE \times ACI)\ \text{summed over each vintage year, measure/program}}$$

Where:

ACI = Present value of the sum of annual avoided capacity cost (AACT), less depreciation

DC = Depreciation of the avoided cost investment

ROE = Weighted return on equity/1-effective tax rate

$$\mathbf{AACT = PD_{kw} \times AAC_{\$/kW/year}\ \text{(for each vintage year)}}$$

Where:

PD = Projected demand impacts for each measure/program by vintage year

AAC = Annual avoided costs per year, including avoided transmission costs

$$ACE = DE + (ROE \times AEI)$$

Where:

DE = Depreciation of the avoided energy investment

AEI = Present value of the sum of annual avoided energy costs (AAET), less accumulated depreciation

$$AAET = PE_{kWh} \times AEC_{\$/kWh/year} \text{ (for each vintage year)}$$

Where:

PE = Projected energy impacts by measure/program by year

AEC = Annual energy avoided costs, calculated as the difference between system energy costs with and without the portfolio of energy efficiency programs.

The mechanism's adjustment factor (BA from the first equation) addresses the true-up and is calculated as follows:

$$BA = AREP - RREP$$

Where:

AREP = Actual revenues from the evaluation period collected by the mechanism (90 percent of avoided cost)

RREP = Revenue requirements for the energy efficiency programs for the same period

All variables apply to and all calculations are performed over the "evaluation period" which is the time period to which the evaluation results apply.

$$AREP = EE \times AKWH \times RREP$$

Where:

EE = The rider charge expressed in cents/kWh

AKWH = Actual sales for the evaluation period by class

$$RREP = 90\% \times [(ACC \times (AD/PD)] + [AEC \times (AE/PE)]$$

Where:

ACC = Avoided capacity revenue requirement for the evaluation period

AD = Actual demand reduction for the period based on evaluation results

PD = Projected demand reduction for the same period

AEC = Avoided energy revenue requirement for the period

AE = Actual energy reduction for the period based on evaluation results

PE = Projected energy reduction for the period.

If evaluated savings (in kilowatt-hours and kilowatts) equal planned savings over the relevant period, then there is no adjustment.

Avoided costs are administratively determined in accordance with North Carolina rules, where avoided costs (both capacity and energy) are calculated based on the peaker methodology and are approved by the North Carolina Utilities Commission on a biannual basis (personal communication with Raiford Smith, Duke Energy, May 25, 2007).

It is important to emphasize that Duke's energy efficiency rider has only recently been filed as of this writing, and the regulatory review has only just begun. The proposal clearly represents an innovation in thinking regarding elimination of financial disincentives for utilities, and it has intuitive appeal for its conceptual simplicity. The Save-a-Watt rider *does* represent a distinct departure from cost recovery and shareholder incentives convention. In its attempt to address the range of financial effects described above in a single mechanism, the rider requires a number of detailed calculations, and estimating the amount of money to be recovered is complicated.

7.3 ISO New England's Market-Based Approach to Energy Efficiency Procurement

The development of organized wholesale markets that allow participation from providers of load reduction creates both an alternative source of funding for energy efficiency projects and a source of revenue that potentially could be used to provide financial incentives for energy efficiency performance.

ISO New England, New England's electricity system operator and wholesale market administrator, is implementing a new capacity market, known as the forward capacity market (FCM). The FCM will, for the first time, permit all demand resources to participate in the wholesale capacity market on a comparable basis with traditional generation resources. Demand resources, as defined by ISO New England's market rules, include energy efficiency, load management, real-time demand response, and distributed generation. An annual forward capacity auction would be held to procure capacity three years in advance of delivery. This three-year window provides developers with sufficient time to construct/complete auction-clearing projects and to reduce the risk of developing new capacity. All capacity providers receive payments during the annual commitment period based upon a single clearing price set in the forward capacity auction. In return, the providers commit to providing capacity for the duration of the commitment period by producing power (if a generator) or by reducing demand (if a demand resource) during specific performance hours (typically peak load hours and shortage hours—hours in which reserves needed for reliable system operation are being depleted) (Yoshimura, 2007, pp. 1–2).

This system creates two revenue pathways. First, non-utility providers of demand reduction, such as energy service companies, municipalities, and retail customers (perhaps through aggregators), could receive a stream of revenues that could help finance incremental energy efficiency projects. Second, utilities in the region could bid the demand reduction associated with energy efficiency programs that they are implementing. The revenues received by utilities from winning bids could be handled in a variety of ways depending on the policy of their state regulators. Traditionally, any revenues earned from these programs would be credited against the utilities' jurisdictional revenue requirement. This approach assumes the programs were funded by ratepayers and therefore, that the benefits from these programs should accrue to ratepayers. However, several alternatives exist to this approach:[2]

- Allow revenues earned from winning bids to be retained by the utilities as financial incentives. Rather than having ratepayers directly fund a performance incentive program, as is typically done, state regulators could allow utilities to retain some or all of the funds received from the capacity auction as a reward for performance and inducement to implement effective programs that reduce system peak load.

- Require that some or all of the revenues earned be applied to the expansion of existing programs or development of new programs.
- Require that the jurisdictional costs of energy efficiency programs be offset by revenues earned from the auction, resulting in a rate decrease for jurisdictional customers.

The ISO New England forward capacity auction is in its very early stages. The initial "show-of-interest" solicitation produced almost 2,500 MW of additional demand reduction potential, of which almost half was in the form of some type of energy efficiency. About 80 percent of the capacity was proposed by non-utility entities (Yoshimura, 2007, p. 4).

While this model represents a new source of revenue to fund energy efficiency investments, it also presents a novel way to capture value from energy efficiency programs by virtue of their ability to reduce wholesale power costs. Increasing the supply of capacity that is bid into the auction, particularly from lower-cost energy efficiency, would likely result in a lower market clearing price for capacity resources, which would lower overall regional capacity costs.

However, whether this model becomes a significant source of revenue to support utility energy efficiency programs is not yet known at this time. Successful implementation of an FCM that allows energy efficiency resources to participate requires that the control area responsible for resource adequacy develop rigorous and complex rules to ensure that the impacts of energy efficiency programs on capability responsibility are real and are not double-counted. Additionally, using a regional capacity market to fund energy efficiency results in all consumers of electricity within the region paying for energy efficiency programs implemented in the region. Accordingly, policy-makers in the region must be prepared for the potential shifting of energy efficiency program cost recovery from jurisdictional ratepayers to all ratepayers in the region. State regulatory policy with respect to the treatment of revenues earned in wholesale markets may or may not provide an incentive for utilities to increase the amount of energy efficiency in response to these markets. Finally, the model works only where there are organized wholesale markets that include a capacity market. Currently, much of the country operates without a capacity market.

7.4 Notes

1. The information in this chapter is drawn largely from the Application of Duke Energy Carolinas, LLC for Approval of Save-a-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs.
2. Note that these alternatives are not mutually exclusive.

8: Final Thoughts— Getting Started

This final chapter provides seven lessons for policy makers to consider as they begin the process of better aligning utility incentives with investment in energy efficiency.

8.1 Lessons for Policy-Makers

The previous four chapters described a variety of options for addressing the barriers to efficiency investment through program cost recovery, lost margin recovery and performance incentive mechanisms. Chapter 2 underscored the principle that it is the combined effect of cost and incentive recovery that matters in the elimination of financial disincentives. There is no single optimal solution for every utility and jurisdiction. Context matters very much, and it is less important that a jurisdiction address each financial effect than that it crafts a solution that leaves utility earnings at least at pre–energy efficiency program implementation levels and perhaps higher.

The history of utility energy efficiency investment is rich with examples of how regulatory commissions and the governing bodies of publicly and cooperatively owned utilities have explored their cost recovery policy options. As these options are reconsidered and reconfigured in light of the trend toward higher utility investment in energy efficiency, this experience yields several lessons with respect to process.

1. **Set cost recovery and incentive policy based on the direction of the market's evolution.** No policy-maker sets a course by looking over his or her shoulder. Nevertheless, there is a natural tendency to project onto the future what seems most comfortable today. The rapid development of technology, the likely integration of energy efficiency and demand response, the continuing evolution of utility industry structure, the likelihood of broader action on climate change, and a wide range of other uncertainties argue for cost recovery and incentive policies that can work with intended effect under a variety of possible futures.

2. **Apply cost recovery mechanisms and utility performance incentives in a broad policy context.** The policies that affect utility investment in energy efficiency are many and varied, and each will control, to some extent, the nature of financial incentives and disincentives that a utility faces. Policies that could impact the design of cost recovery and incentive mechanisms include those having to do with rate design (PBR, dynamic pricing, SFV designs, etc.); non-CO_2 environmental controls such as NO_X cap-and-trade initiatives; broader clean energy and distributed energy development; and the development of more liquid wholesale markets for load reduction programs.

3. **Test prospective policies.** Cost recovery and incentive discussions have tended toward the conceptual. What is appropriate to award and allow? Is it the utilities' responsibility to invest in energy efficiency, and do they need to be rewarded for doing so? Should revenues be decoupled from sales? All questions are appropriate and yet at the end of the day, the answers tell policy-makers very little about how a mechanism will impact rates and earnings. This answer can only come from running the numbers—test driving the policy—and not simply under the standard business-as-usual scenario. Business is never "as usual," and a sustainable, durable policy requires that it generate acceptable outcomes under unusual circumstances. Complex mechanisms that have many moving parts cannot easily be understood absent simulation of the mechanisms under a wide range of conditions. This is particularly true of mechanisms that rely on projections of avoided costs, prices, or program impacts.

4. **Policy rules must be clear.** Earlier chapters of this Report described the relationship between perceived financial risk and utility disincentives to invest in energy efficiency. This risk is mitigated in part by having cost recovery and incentive mechanisms in place, but the effectiveness of these mechanisms depends very much on the rules governing their application. For example, review and approval of energy efficiency program budgets by regulators prior to implementation provides utilities with greater assurance of subsequent cost recovery. Alternatively, spelling out what is considered prudent in terms of planning and investment can help allay concerns over post-implementation disallowances. Similarly, the criteria/methods to be applied when reviewing costs, recovery of lost margins, and claimed incentives should be as specific as possible, recognizing the need to preserve regulatory flexibility. Where possible, the values of key cost recovery and incentive variables, such as avoided costs, should be determined in other appropriate proceedings, rather than argued in cost recovery dockets. Although this clear separation of issues will not always be possible, the principal focus of cost recovery proceedings should be on (1) whether a utility adhered to an approved plan and, if not, whether it was prudent in diverging, and (2) whether costs and incentives proposed for recovery are properly calculated.

5. **Collaboration has value.** Like every issue involving utility costs of service, recovering the costs associated with program implementation, recovering lost margins/fixed costs, and providing performance incentives will involve determinations of who should pay how much. These decisions invariably will draw active participation from a variety of stakeholders. Key among these are utilities, consumer advocates, environmental groups, energy efficiency proponents, and representatives of large energy consumers. Fashioning a cost recovery and incentives policy will be challenging. The most successful and sustainable cost recovery and incentive policies are those that (1) were based on a consultative process that includes broad agreement on the general aims of the energy efficiency investment policy, and (2) are based on legislative enactment of clear regulatory authority to implement the policy.

6. **Flexibility is essential.** Most of the states that have had significant efficiency investment and cost recovery policies in place for more than a few years have found compelling reasons to modify these policies at some point. Rather than indicating policy inconsistency, these changes most often reflect an institutional capacity to acknowledge either weaknesses in existing approaches or broader contextual changes that render prior approaches ineffective. Minnesota developed and subsequently abandoned a lost margin recovery mechanism after finding that its costs were too high, but the state replaced the mechanism with a utility performance incentive policy that appears to be effective in addressing barriers to investment. California adopted, abandoned, and is now set to again adopt performance incentive mechanisms as it responds to broader changes in energy market structure and the role of utilities in promoting efficiency. Nevada adopted a bonus rate of return for utility efficiency investments and is now reconsidering that policy in the context of the state's aggressive resource portfolio standard. Policy stability is desirable, and changes that suggest significant impacts on earnings or prices can be particularly challenging, but it is the stability of impact rather than adherence to a particular model that is important in addressing financial disincentives to invest.

7. **Culture matters.** One important test of a cost recovery and incentives policy is its impact on corporate culture. A policy providing cost recovery is an essential first step in removing financial disincentives associated with energy efficiency investment, but it will not change a utility's core business model. Earnings are still created by investing in supply-side assets and selling more energy. Cost recovery, plus a policy enabling recovery of lost margins might make a utility indifferent to selling or saving a kilowatt-hour or therm, but still will not make the business case for aggressive pursuit of energy efficiency. A full comple-

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ment of cost recovery, lost margin recovery, and performance incentive mechanisms can change this model, and likely will be needed to secure sustainable funding for energy efficiency at levels necessary to fundamentally change resource mix.

As utility spending on energy efficiency programs rises to historic levels, attention increasingly falls on the policies in place to recover program costs, recover potential lost margins, and provide performance incentives. These policies take on even greater importance if utilities are expected to go beyond current spending mandates and adopt investment in customer energy efficiency as a fundamental element of their business strategy. The financial implications of utility energy efficiency spending can be significant, and failure to address them ensures that at best, utilities will comply with policies requiring their involvement in energy efficiency, and at worst, it could lead to ineffective programs and lost opportunities.

This paper has outlined the financial implications surrounding utility funding for energy efficiency and the mechanisms available for addressing them, with the intent of supporting policies that align utility financial incentives with investment in cost-effective energy efficiency. The variety of policy options is testament to the creativity of state policy-makers and utilities, but as pressure for higher efficiency spending levels increases, the volume of the debate surrounding these options also increases. To a great extent, the debates revolve around the basic tenets of utility regulation. Some efficiency cost recovery, margin recovery, and performance incentive mechanisms imply changes in the approach to utility regulation and ratemaking.

Building the consensus necessary to support significant increases in utility administration of energy efficiency will require that these tenants be revisited. If state and federal policy-makers conclude that utilities should play an increasingly aggressive role in promoting energy efficiency, adaptations to these tenants to accommodate this role will need to be explored. An important first step may be building a common understanding around the financial implications of utility spending for efficiency, including development of a consistent cost accounting framework and terminology.

Appendix **A:**

National Action Plan for Energy Efficiency Leadership Group

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Appendix B: Glossary

Decoupling: A mechanism that weakens or eliminates the relationship between sales and revenue (or more narrowly the revenue collected to cover fixed costs) by allowing a utility to adjust rates to recover authorized revenues independent of the level of sales.

Energy efficiency: The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. "Energy conservation" is a term that has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to perform the same or better function.

Fixed costs: Expenses incurred by the utility that do not change in proportion to the volume of sales within a relevant time period.

Lost margin: The reduction in revenue to cover fixed costs, including earnings or profits in the case of investor-owned utilities. Similar to lost revenue, but concerned only with fixed cost recovery, or with the opportunity costs of lost margins that would have been added to net income or created a cash buffer in excess of that reflected in the last rate case.

Lost revenue adjustment mechanisms: Mechanisms that attempt to estimate the amount of fixed cost or margin revenue that is "lost" as a result of reduced sales. The estimated lost revenue is then recovered through an adjustment to rates.

Performance-based ratemaking: An alternative to traditional return on rate base regulation that attempts to forego frequent rate cases by allowing rates or revenues to fluctuate as a function of specified utility performance against a set of benchmarks.

Program cost recovery: Recovery of the direct costs associated with program administration (including evaluation), implementation, and incentives to program participants.

Shared savings: Mechanisms that give utilities the opportunity to share the net benefits from successful implementation of energy efficiency programs with ratepayers.

Return on equity: Based on an assessment of the financial returns that investors in that utility would expect to receive, an expectation that is influenced by the perceived riskiness of the investment.

Straight fixed-variable: A rate structure that allocates all current fixed costs to a per customer charge that does not vary with consumption.

System benefits charge: A surcharge dictated by statute that is added to ratepayers' bills to pay for energy efficiency programs that may be administered by utilities or other entities.

Throughput incentive: The incentive for utilities to promote sales growth that is created when fixed costs are recovered through volumetric charges. Many have identified the throughput incentive as the primary barrier to aggressive utility investment in energy efficiency.

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Appendix C: Sources for Policy Status Table

This appendix provides specific sources by state for the status of energy efficiency cost recovery and incentive mechanisms provided in Tables ES-1 and 1-2.

Table C-1. Policy Status Table

States	Sources
Arizona	Arizona Corporation Commission, Decision Nos. 67744 and 69662 in docket E-01345A-05-0816
California	2001 California Public Utilities Code 739.10. D.04-01-048, D.04-03-23, D.04-07-022, D.05-03-023, D.04-05-055, D.05-05-055
Colorado	House Bill 1037 (2007) authorizes cost recovery and performance incentives for both gas and electric utilities
Connecticut	2005 Energy Independence Act, Section 21
District of Columbia	Code 34-3514
Florida	Florida Administrative Code Rule 25-17.015(1)
Hawaii	Docket No. 05-0069, Decision and Order No. 23258
Idaho	Idaho PUC Case numbers IPC-E-04-15 and IPC-E-06-32
Illinois	Illinois Statutes 20-687.606
Indiana	Case-by-case
Iowa	Iowa Code 2001: Section 476.6; 199 Iowa Administrative Code Chapter 35
Kentucky	Kentucky Revised Statute 278.190
Maine	Maine Statue Title 35-A

Table C-1. Policy Status Table (continued)

States	Sources
Massachusetts	D.T.E. 04-11 Order on 8/19/2004
Minnesota	Statutes 2005, 216B.24 1
Montana	Montana Code Annotated 69.8.402
Nevada	Nevada Administrative Code 704.9523
New Hampshire	Order 23-574, 2000. Statues Chapter 374-F:3
New Jersey	N.J.S.A. 46:3-60
New Mexico	New Mexico Statues Chapter 62-17-6
New York	Case 05-M-0900, In the Matter of the System Benefits Charge III, Order Continuing the System Benefits Charge (SBC)
North Carolina	Order on November 3, 2005 Docket G-21 Sub 461
Ohio	Case-by-case
Oregon	Order 02-634
Rhode Island	Rhode Island Code 39-2-1.2
Utah	<www.raponline.org/showpdf.asp?PDF_URL=%22/pubs/irpsurvey/irput2.pdf%22 and Questar Order>
Washington	Case-by-case
Wisconsin	Wisconsin Statute 16.957.4

Appendix D: Case Study Detail

This appendix provides additional detail on the Iowa and Florida case studies discussed in this Report.

D.1 Iowa

199 Iowa Administrative Code Chapter 35[1] specifies the application of the cost recovery rider.

Energy efficiency cost recovery (ECR) factors, must be calculated separately for each customer or group classification. ECR factors are calculated using the following formula:

$$\text{ECR factor} = ((PAC) + (ADPC \times 12) + (ECE) + A)/ASU$$

where:

- The ECR factor is the recovery amount per unit of sales over the 12-month recovery period.
- PAC is the annual amount of previously approved costs from earlier ECR proceedings, until the previously approved costs are fully recovered.
- ECE is the estimated contemporaneous expenditures to be incurred during the 12-month recovery period.
- "A" is the adjustment factor equal to over-collections or under-collections determined in the annual reconciliation, and for adjustments ordered by the board in prudence reviews.
- ASU is the annual sales units estimated for the 12-month recovery period.
- ADPC is amortized deferred past cost. It is calculated as the levelized monthly payment needed to provide a return of and on the utility's deferred past costs (DPC). ADPC is calculated as:

$$ADPC = DPC\,[r(1+r)n] \div [(1+r)n - 1]$$

where:

- DPC is deferred past costs, including carrying charges that have not previously been approved for recovery, until the deferred past costs are fully recovered.
- n is the length of the utility's plan in months.
- r is the applicable monthly rate of return calculated as:

$$r = (1+R)^{1/12} - 1 \text{ or}$$

$$r = R/12 \text{ if previously approved}$$

- R is the pretax overall rate of return the board held just and reasonable in the utility's most recent general rate case involving the same type of utility service. If the board has not rendered a decision in an applicable rate case for a utility, the average of the weighted average cost rates for each of the capital structure components allowed in general rate cases within the preceding 24 months for Iowa utilities providing the same type of utility service will be used to determine the applicable pretax overall rate of return.

D.2 Florida

The procedure for conservation cost recovery described by Florida Administrative Code Rule 25-17.015(1)[2] includes the following elements:

- Utilities submit an annual final true-up filing showing the actual common costs, individual program costs and revenues, and actual total ECCR revenues for the most recent 12-month historical period from January 1 through December 31 that ends prior to the annual ECCR proceedings. As part of this filing a utility must include:

- A summary comparison of the actual total costs and revenues reported, to the estimated total costs and revenues previously reported for the same period covered by the filing. The filing shall also include the final over- or under-recovery of total conservation costs for the final true-up period.
  - Eight months of actual and four months of projected common costs, individual program costs, and any revenues collected. Actual costs and revenues should begin January 1, immediately following the period described in paragraph (1)(a). The filing shall also include the estimated/actual over- or under-recovery of total conservation costs for the estimated/actual true-up period.
  - An annual projection filing showing 12 months of projected common costs and program costs for the period beginning January 1, following the annual hearing.
  - An annual petition setting forth proposed ECCR factors to be effective for the 12-month period beginning January 1, following the hearing.
- Within the 90 days that immediately follow the first six months of the reporting period, each utility must report the actual results for that period.
- Each utility must establish separate accounts or sub-accounts for each conservation program for the purposes of recording the costs incurred for that program. Each utility must also establish separate sub-accounts for any revenues derived from specific customer charges associated with specific programs.
- New programs or program modifications must be approved prior to a utility seeking cost recovery. Specifically, any incentives or rebates associated with new or modified programs may not be recovered if paid before approval. However, if a utility incurs prudent implementation costs before a new program or modification has been approved by the commission, a utility may seek recovery of these expenditures.

Advertising expense recovered through ECCR must be directly related to an approved conservation program, shall not mention a competing energy source, and shall not be company image-enhancing.

D.3 Notes

1. 199 Iowa Administrative Code Chapter 35, accessed at <http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf>.
2. Florida Administrative Code Rule 25-17.015(1), accessed at <http://www.flrules.org/gateway/RuleNo.asp?ID=25-17.015>.

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State Energy Efficiency Regulatory Frameworks

December 2009

Contents

Policies at the state level continue to help utilities pursue more scalable, and sustainable energy efficiency programs. **This review summarizes ongoing and the most recent policies that promote program cost recovery, lost revenue recovery, and performance incentive mechanisms on a state-by-state basis.** Some recent developments are highlighted below.

- Washington, DC, is the latest addition to a growing list of states that have adopted revenue decoupling for their electric sector (state summary & map, p. 5). Idaho, Massachusetts, Minnesota, Oregon, Wisconsin and Vermont have also approved decoupling measures in the past two years. Delaware, Hawaii, Michigan, New Hampshire, New Jersey and New Mexico are considering some form of decoupling. Lost revenue adjustment mechanisms were recently approved in Ohio, North Carolina, and South Carolina as part of larger cost recovery mechanisms. Utah also recently entered the discussion by passing a law that encourages utilities and the Commission to investigate decoupling mechanisms.
- Twenty states currently have incentives in place, with another nine states pending (p. 9). Colorado, Kentucky, Michigan, Ohio, Oklahoma, North Carolina, Texas, South Carolina, Washington, and Wisconsin have approved new incentive mechanisms in the last two years; Idaho, Indiana, Kansas, Montana, New Mexico, North Carolina, New York, and Utah are each considering some form of performance incentive for efficiency.
- Duke Energy has proposed a "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, in each of its five service territories. Ohio approved the program in 2008 and decisions are expected soon in North and South Carolina. ■

State Regulatory Framework Summary Table

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
Alabama	Yes						
Alaska							
Arizona	Yes	Yes				Yes	
Arkansas			Yes				
California	Yes	Yes		Yes		Yes	
Colorado	Yes		Yes			Yes	
Connecticut		Yes		Yes		Yes	
Delaware	Yes			Pending			
District of Columbia	Yes			Yes			
Florida			Yes				
Georgia	Yes					Yes (one program)	
Hawaii	Yes			Pending			
Idaho			Yes	Yes		Pending	
Illinois			Yes				
Indiana	Yes						Pending
Iowa	Yes		Yes				
Kansas	Yes					Pending	
Kentucky			Yes		Yes	Yes	Pending
Louisiana							
Maine		Yes					
Maryland			Yes	Yes			
Massachusetts		Yes		Yes		Yes	
Michigan			Yes		Pending	Pending	
Minnesota	Yes			Yes		Yes	
Mississippi	Yes						
Missouri	Yes						
Montana		Yes				Pending	
Nebraska							
Nevada	Yes					Yes	
New Hampshire		Yes		Pending		Yes	

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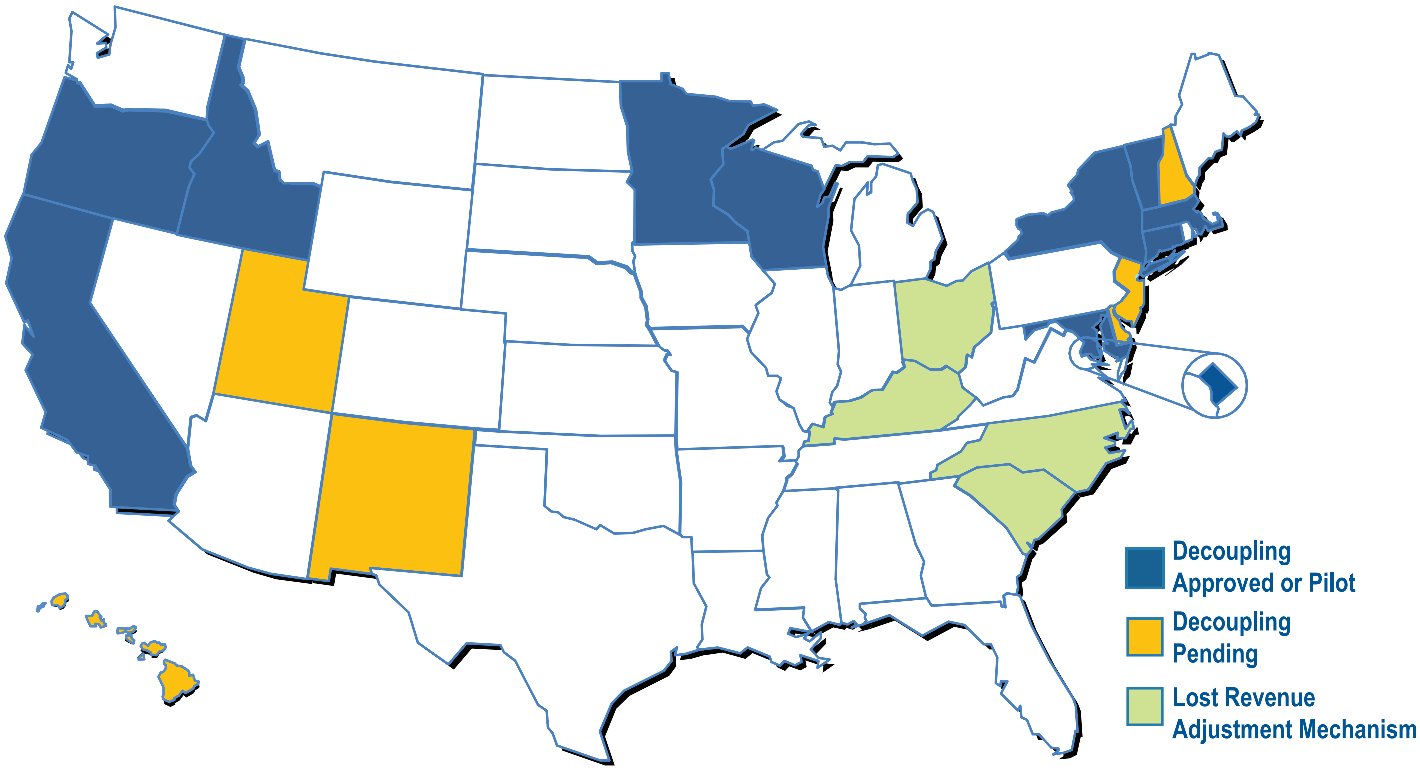
State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
New Jersey		Yes		Pending			
New Mexico			Yes			Pending	
New York		Yes		Yes		Pending	
North Carolina			Yes		Yes	Yes	Pending
North Dakota							
Ohio			Yes		Yes		Yes
Oklahoma		Yes				Yes	
Oregon		Yes		Yes			
Pennsylvania	Yes						
Rhode Island		Yes				Yes	
South Carolina		Yes			Yes	Yes	Pending
South Dakota							
Tennessee							
Texas	Yes					Yes	
Utah	Yes		Yes			Pending	
Vermont		Yes		Yes		Yes	
Virginia							
Washington		Yes	Yes			Yes	
West Virginia							
Wisconsin	Yes	Yes		Yes		Yes	
Wyoming							

Please note that although information in this document was compiled from primary sources, readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net.
For further information, please visit http://www.edisonfoundation.net/IEE/.

Lost Revenue Adjustment & Revenue Decoupling Mechanisms for Electric Utilities by State



State	Description	Status	Codes, Orders & Resources
California	California has had some form of decoupling since 1982. The current "decoupling plus" program is a revenue decoupling program combined with performance incentives for meeting or exceeding energy efficiency targets (performance-based rates). Revenue requirements are adjusted for customer growth, productivity, weather, and inflation on an annual basis with rate cases every three or four years (varies by utility). The incentive structure caps penalties/earnings for energy efficiency programs at $450M.	Approved (Decoupling "Plus" approved in 2007)	CA Code Sec. 9 Section 739(3) and Sec. 10 Section 739.10 as amended by A.B. XI 29; Decisions 98-03-063 & 07-09-043
Connecticut	As of 2007, all electric and gas utilities must include a decoupling proposal as a part of their individual rate cases. The type of decoupling is assigned on a utility-by-utility basis. United Illuminating uses a full decoupling mechanism, adjusted annually. Connecticut Light & Power will submit a proposal for a decoupling mechanism in their next rate case.	Approved (2007)	CT Public Act No. 07-242
Delaware	The Delaware Commission has recognized decoupling as a possible solution for promoting energy efficiency, but no plans have yet been approved for Delaware utilities. Delmarva Power will submit their decoupling plan in the next rate case in 2009.	Pending	DE Docket 59

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State	Description	Status	Codes, Orders & Resources
District of Columbia	The DC Public Service Commission approved PEPCO's Bill Stabilization Adjustment (BSA) in October 2009. Like the BSA approved for Maryland, an RPC mechanism is employed which adjusts quarterly.	Approved (2009)	DC PSC Order 1053-E-549
Hawaii	An order was issued in October 2008 to investigate implementing a decoupling mechanism that could be structured much like that in California. Utilities are required to submit a 2009 test year rate case.	Pending	HI Docket 2008-0274
Idaho	A three year pilot for a fixed-cost adjustment (an RPC decoupling program) has been instituted and is currently employed by Idaho Power Company. Sales are adjusted for weather and rate increases are capped at 3% over the previous year. The mechanism is only applied to residential and small general service customers.	Approved - Pilot (2007)	ID PUC IPC-E-09-07, Order No. 30829
Kentucky (LR)	Lost revenue recovery mechanisms are determined on a case-by-case basis, but all electric utilities in Kentucky have DSM proposals in place that include similar lost revenue (LR) recovery due to DSM programs. For these utilities, LR is calculated using the marginal rate, net of variable costs, times the estimated kWh savings from a DSM measure over a three-year period.	Approved (2006)	KY Statute Ch. 278, Title 285; Docket 2007-00477; 2008-00473
Maryland	A plan to employ revenue decoupling for Maryland utilities under an RPC mechanism was approved in 2007, which adjusts quarterly. The mechanism is similar to the BSA approved for Washington, DC.	Approved (2007)	MD PSC Case No. 9093; Order 81518
Massachusetts	Gas and electric utilities in Massachusetts must include a decoupling proposal in their next rate case. Target revenues are determined on a utility-wide basis (full decoupling) and can be adjusted for inflation or capital spending requirements if necessary. The Massachusetts DPU expects that all utilities will have fully operational decoupling plans by 2012. In May 2009, National Grid was the first utility to submit a revenue decoupling ratemaking plan (RDR), which proposes an RPC mechanism that adjusts annually.	Approved (2008), full implementation by 2012	MA Docket 07-50; Docket 09-39
Michigan	Act 295 mandates that the Commission consider decoupling mecahnisms proposed by the state's electric utilities. Consumers Energy and Detroit Edison have included decoupling proposals in the rate cases currently before the Commission. A decision in each case is expected in late 2009 or early 2010.	Pending	MI Act 295
Minnesota	A decoupling statute was passed in 2008 that allows for electric and gas utilities to implement decoupling pilot programs of no more than three years. Utilities are required to submit proposals to the state PUC for the structure of recovery mechanisms and frequency of true-ups (none submitted to date). Annual status reports are to be given to the state legislature once the programs are in place.	Approved - Pilot (2008)	MN Statute 216B.2412

State	Description	Status	Codes, Orders & Resources
New Hampshire	The New Hampshire PUC concluded in a January 2009 order that existing rate mechanisms are a barrier to energy efficiency. It has ordered that future rate mechanisms be tailored to individual utilities and be normalized for changes in weather, while not specifying the parameters of those mechanisms.	Pending	NH Order DE 07-064
New Jersey	Atlantic City Electric has proposed a RPC mechanism, or Bill Stabilization Agreement (BSA) as proposed, for their service territory. It is an RPC mechanism that calls for monthly true-ups with changes capped at 10% of previous fixed revenue amounts.	Pending	NJ Docket Eo09010056
New Mexico	HB 305 was signed into law in 2008, requiring that all utilities "include all cost-effective energy efficiency and load management programs in their energy resource portfolios, that regulatory disincentives to public utility devlopment of cost-effective energy efficiency and load managment be removed [...]." As a result, the NM Public Regulation Commission is considering proposals for a lost revenue adjustment mechanism that would compensate the utilities based on lost margins through 2010, at which time the PRC may act to remove disincentives to EE through decoupling or other mechanims (see the incentives summary for more information on the proposed incentive mechanism). A decision is pending.	Pending	NM HB305, Docket 08-00024-UT
New York	Following an April 2007 order, electric and gas utilities must file proposals for true-up based decoupling mechanisms in ongoing and new rate cases. Proposals have been approved for Consolidated Edison and Orange & Rockland utilities, both for revenue-per-class mechanisms. True-ups occur annually.	Approved (2007)	NY Cases 03-E-0640, 07-E-0949, & 07-E-0523
North Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues are determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually and the mechanism will expire in 2012.	Approved (2009)	NC Docket E-2, Sub 931

State	Description	Status	Codes, Orders & Resources
Ohio (LR)	As with Kentucky, lost revenue recovery mechanisms are determined on a case-by-case basis. Duke Energy Ohio recovers lost revenues resulting from their portfolio of EE programs through the DSM rider. LR is calculated as the amount of kWh sales lost due to the DSM programs times the energy charge for the applicable rate schedule, less variable costs, divided by the expected kilowatt-hour sales for the upcoming 12 month period. They are collected over a 36 month period. DP&L currently has a case pending. AEP Ohio chose not to seek LR in their prior rate case.	Approved (2007)	ORC §4928.143(B)(2)(h); 06-0091-EL-UNC
Oregon	Portland General Electric was approved for a two year pilot employing an RPC decoupling mechanism. True-ups will occur annually.	Approved - Pilot (2009)	OR Order 09-020
South Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues are determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually and the mechanism will expire in 2012.	Approved (2009)	SC Docket 200-251-E
Utah	HJR 9 was passed into law (March 2009), which includes language supporting decoupling: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed, mechanisms yet to be proposed	UT HJR009
Vermont	An RPC decoupling program was approved for Green Mountain Power under the Alternative Regulation Plan. Rates can be adjusted up to four times per year with an annual reconciliation on allowed earnings. Changes in base rates cannot exceed ~2% per year. CVPS was also approved for decoupling in 2008.	Approved (2007)	VT Dockets 7175, 7176 & 7336
Wisconsin	Decoupling was approved for WPSC in December 2008 (specified as a "Revenue Stabilization Mechanism"), allowing the utility to pursue a four-year pilot program. WPSC is required to pursue three community-based pilots, which will be regularly reviewed (at 2, 12, 24, and 30 months). True-ups occur annually and over- or under-collection is capped at approximately $14 million. WPL will submit a similar proposal for implementation in 2010.	Approved - Pilot (2008)	WI Dockets 6680-UR-116 (WPL) & 6690-UR-119 (WPSC)

The table of lost revenue recovery mechanims was prepared by the Institute for Electric Efficiency using the latest public data available as of December 11th, 2009. Readers are encouraged to verify the most recent developments in decoupling by contacting the appropriate state regulator or commissioner's office.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.

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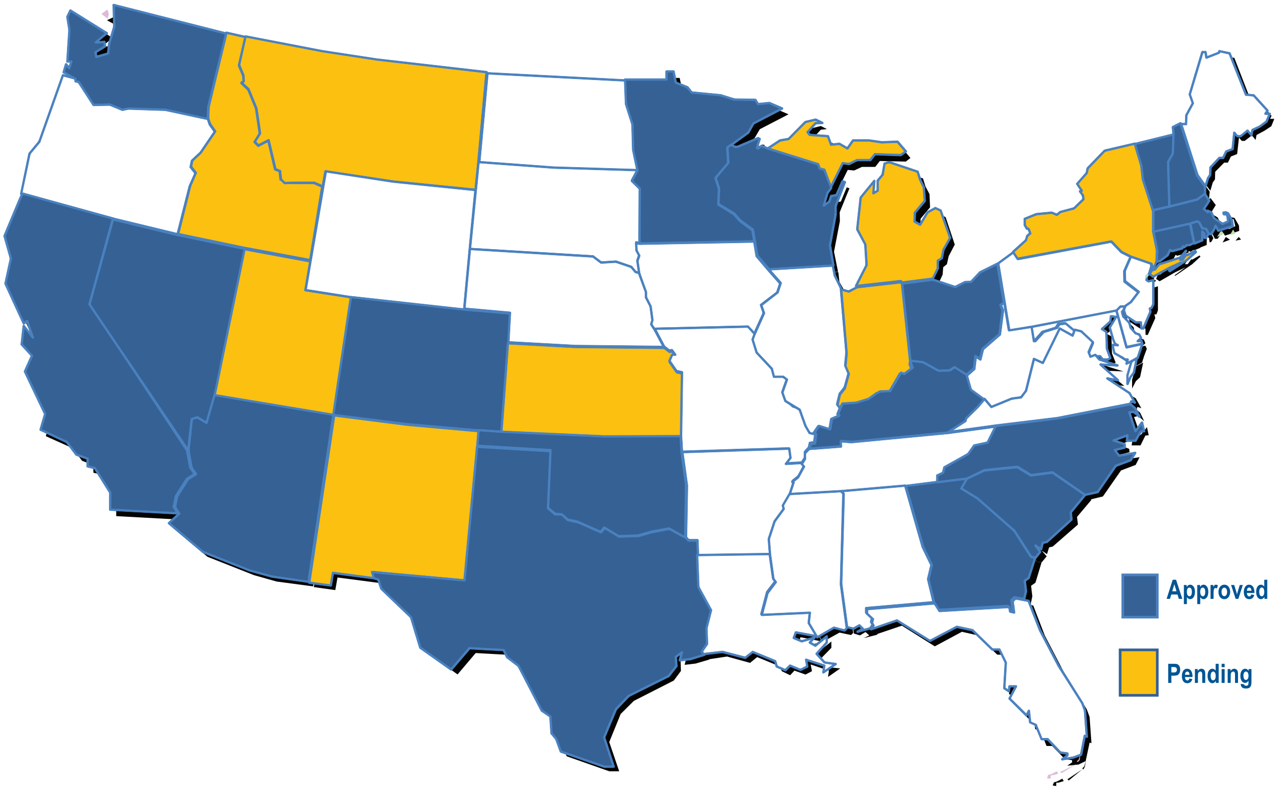
Performance Incentives for Energy Efficiency by State



State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Arizona	Arizona Public Service (APS) has performance incentives in place under a shared savings mechanism, set at 10% of DSM program net economic benefits and capped at 10% of total DSM expenditures. An APS proposal to modify the incentive mechanism in 2008 requesting recovery of net lost revenues as well as removal of the cap on the incentive was denied.	Approved (2005)	Decision 67744, Docket E-01345A-05-0816, et al
California	California utilities earn an incentive on energy efficiency programs under a shared savings mechanism called an energy efficiency risk-reward incentive mechanism. Revenue from eligible energy efficiency programs is the product of the Earnings Rate (ER) and net benefits. The ER is 12% if the utility achievement towards CPUC goals is greater than 100%, 9% if the goal achievement is between 85 and 100% and 0% if the goal achievement is between 65 and 85%; if the achievement of goals is less than 65%, the utility pays a penalty. Net benefits are calculated as two-thirds of the TRC Net Benefit and one-third of the PAC Net Benefit. In January 2009, the CPUC instituted a rulemaking (09-01-019) to examine and reform the EE incentive mechanism.	Approved (2007)	R.06-04-010; 09-01-019

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State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Colorado	HB 07-1037 (C.R.S. §40-3.2-104) requires investor-owned electric utilities to achieve at least 5% percent reduction of retail energy sales and capacity savings by 2018, based on 2006 sales. The law further states that the Commission shall allow electric DSM investments an opportunity to be more profitable to the utility than any other utility investment that is not already subject to an incentive. The Commission approved the following incentive package to Public Service Colorado: - A "disincentive offset" of $2m/year (after tax) for each year approved DSM plan implemented to offset lost margins; if < 80% of yearly energy goal achieved, the offset may be reduced. - Performance incentives for surpassing "modest" goals; for each 1% of goal reached beyond 80%, company to earn additional 0.2% of net economic benefits, up to 10% at 130% of goal attainment, up to 12% at 150% of goal attainment. Incentives adjusted for 2009 to reflect least-cost planning commitments. - Incentives are allowed via annually trued up DSM Cost Adjustment and are capped at 20% of total annual DSM expenditures.	Approved (2007)	HB-07-1037; Decision C08-560, Docket 07A-420E
Connecticut	The CT PUC requires annual hearings for utilities, where the past year's results for energy savings are reviewed and a performance incentive is determined, which ranges from 1% to 8% of program costs. The minimum threshold of 70% of goals earns the minimum (1%) incentive. Reaching 100% of goals earns 5%, and for reaching 130% of goals earns 8%.	Approved (first in 1988, mechanism changes over time)	Docket 07-10-03
Georgia	Although utilities in Georgia may recover costs and an additional sum for Commission-approved DSM programs, only the Power Credit Single Family Program (Georgia Power) is currently active. The utility may earn an additional sum of 15% of the NPV of the net benefits of the program, contingent on the program achieving at least 50% of projected participation levels.	Approved - Single program only (2007)	Case 24505-U
Idaho	Idaho Power (IPC) was approved for a three-year pilot beginning in January 2007 and ending in December 2009. Under the pilot, the Company receives an incentive payment if the market share of homes constructed under the ENERGY STAR Homes Northwest program exceeds a target percentage of new homes constructed. IPC earns an incentive if the program exceeds the market share goal (7% in 2007, 9.8% in 2008, 11.7% in 2009). Incentives are capped at 10% of program net benefits. Penalties are levied if IPC does not meet a minimum market share percentage. On May 14, 2009, it was ordered that Idaho Power neither earn an incentive nor incur a penalty for the ENERGY STAR related program and that the pilot program be discontinued retroactively as of January 1, 2009.	Approved - Pilot (2007); Discontinued (Jan. 1, 2009)	IPC-E-06-32, Order 30268; IPC-E-09-04

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State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Indiana	The state statute allows for either shared savings or adjusted/bonus ROE mechanisms as DSM incentives. Duke Energy has submitted a proposal for an avoided cost recovery charge for EE programs. Vectren Energy Indiana, Northern Indiana Public Service Company (NIPSCO), and Indianapolis Power and Light have also filed DSM plans requesting performance incentives. All cases are currently pending.	Pending	IN Administrative Code, Title 170, Art. 4; Cause No. 43374; Cause No. 43427; Cause No. 43618; Cause 43623
Kansas	The State Corporation Commission found that it has "broad authority to provide incentives for energy efficiency" in 2007, but did not specify a mechanism in that order. Kansas Statute 66-117 allows a return of 0.5% to 2% on energy efficiency investments above the allowed rate of return. No plans have yet been approved for any utilities.	Pending; law in place, no programs approved	Docket 08-GIMX-441-GIV; Statute 66-117
Kentucky	State law allows for shareholder incentives through the DSM statute, specifically "incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs." Incentive mechanisms are approved on a case-by-case basis and both Duke Energy and Kentucky Power (AEP) have a shared savings mechanism in place where they receive an incentive of up to 10% of program costs for exceeding goals.	Approved (2007)	KY Rev. Stat. 278.285(1)(c); Docket 2008-00473; 2007-00477
Massachusetts	The incentive allows utilities to earn about 5% of program costs for energy efficiency programs that meet established program goals. The incentive structure is determined on a program-by-program basis but generally utilizes a three-tiered structure. The first "design performance" level is defined as performance that a Program Administrator expects to achieve in implementing its energy efficiency programs. The second "threshold performance" level is 75% of the design level. The third "exemplary performance" level is 125% of the design level. Incentives are awarded only if a program achieves the threshold level or above.	Approved (2000)	Docket 04-11; Order 98-100
Michigan	PA 295 contains two provisions authorizing utilities to receive an economic incentive for energy efficiency programs. To be eligible, utilities must request that appropriate energy efficiency program costs be capitalized and earn a normal rate of return. Utilities can request a performance incentive mechanism to provide additional earnings to shareholders if they exceed the annual energy savings target. Incentives are capped at 15% of the total program cost.	Pending	PA 295 (2008); U-15806 (Commission's Temporary Order)

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Minnesota	The PUC approved a performance-based incentive mechanism for utility energy efficiency programs in 1999. Utilities are rewarded based on a specific percentage of net benefits. The percentage of net benefits awarded increases as the percentage of the energy savings goal achieved increases. The threshold to receive incentives is 91% of savings goals; the utility will receive approximately 30% of program costs if it achieves 150% of target savings. The incentives are funded through a rate adjustment the following year.	Approved (1999)	Statute 216B.241
Montana	MT statute allows for the Public Service Commission to add 2% to the authorized rate of return for DSM investments. It has not yet been approved for a specific utility.	Passed into law, but not implemented by utility	MT Code 69-3-712
Nevada	Nevada revised its regulations for IRP and DSM in 2004 to allow utilities to earn as much as 500 basis points above allowed return-on-equity (ROE) for applicable, approved DSM costs (+5%). Utilities must follow approved plans and budgets to earn the incentive amount. The order calls for applying the utility's debt-to-equity ratio to the fraction of capitalized DSM costs, and then applying the extra 5% ROE to that amount.	Approved (2004)	Docket No. 02-5030
New Hampshire	There are two separate incentives in NH. The cost-effectiveness incentive is awarded for programs that achieve a cost effectiveness ratio of 1.0 or higher. The incentive is calculated as 4% of the planned EE budget times the ratio of actual to planned cost effectiveness. The energy savings incentive is awarded when actual lifetime kWh savings are greater than or equal to 65% of projected savings. The incentive is 4% of the planned EE budget times the ratio of actual to planned energy savings. Target incentive amounts are calculated separately for residential and commercial/industrial sectors and are capped at 12% of the planned sector budgets.	Approved (2000)	Order 23.574
New Mexico	A proposed rule making is currently before the PSC that, if approved, would allow utilities to receive an incentive for EE based on energy saved and to receive compensation for revenue lost due to efficiency programs. Additionally, HB 305 was passed in 2008 which requires all utilities to "include all cost-effective energy efficiency and load management programs in the energy resource portfolios."	Pending	Case 08-00024-UT; NM HB 305
New York	New York has recently allowed for performance incentives to be included in utility rate cases and the Commission is in the process of reviewing energy efficiency plans of several NY utilities. The order caps the aggregate incentives at $40M per year statewide and target megawatt-hours will be set for each year at the time of review for the EE plans.	Pending	Case 07-M-0548

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State	Performance Incentive Description	Status	Relevant Statute, Code or Order
North Carolina	North Carolina state law states that a utility may propose incentives for demand side management or energy efficiency programs to the Commission for consideration. The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs. The Commission is considering an avoided cost recovery mechanism submitted by Duke Energy. Duke's EE programs were approved in May 2009 with an ability to implement June 1, but there was no settlement on the regulatory model. Duke Energy and the environmental intervenors, an alliance of environmental groups, reached a settlement in June 2009. The settlement contains more aggressive performance targets (~2%), with an earnings cap of 5% if Duke achieves <60% of the target and a cap of 15% if it achieves >90% of the target.	Approved for Progress Energy Carolinas (2009); Pending for Duke Energy	NCUC Docket E-2, sub 931; Docket E-7, Sub 831
Ohio	Duke Energy received approval in December of 2008 for its proposed "Save-a-Watt" program, where the utility will receive 50% of the net present value (NPV) of the avoided costs for energy conservation and 75% of the NPV of the avoided costs for demand response. Demand response programs are viewed by the parties as having a useful life of 1 year, while energy conservation programs have useful lives of up to 15 years.	Approved (2008)	OH Docket 08-920-EL-SSO
Oklahoma	A shared savings program has been approved for Public Service Oklahoma (AEP) which allows for two different returns: an incentive of 25% of net savings for programs for which savings can be estimated and 15% of the costs for other programs (e.g. education and marketing programs).	Approved (2008)	OK Cause No. PUD 200700449; Order 555302
Rhode Island	The shareholder incentive mechanism includes two components: performance-based metrics for specific program achievements, and kWh savings targets by sector. The program performance metrics are established for each individual program, such as achieving specific savings or a certain market share for the targeted energy-efficient technology. If Narragansett (d/b/a National Grid) achieves the savings goal, it receives 4.4% of the eligible budget. The threshold performance level is 60% of the savings goal. Once the threshold level has been reached, the utility has the ability to earn an additional incentive per kWh saved up to 125% of target savings. Incentive rates change by customer class.	Approved (2005)	RI Docket 3635, Order 18152
South Carolina	South Carolina law stipulates that the PSC "may adopt procedures that encourage electrical utilities [...] to invest in cost-effective energy efficient technologies and energy conservation programs." The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs.	Approved for Progress Energy Carolinas (2009); Pending for Duke Energy	SC Title 58. Public Utilities, Services And Carriers, Chapter 37. Energy Supply And Efficiency; Dockets 2008-251-E (Progress Energy), 2007-358-E, & 2008-251-E (Duke Energy)

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State	Performance Incentive Description	Status	Relevant Statute, Code or Order
South Carolina (Continued)	(Continued) Duke Energy's original avoided cost mechanism was rejected, but the Commission invited resubmission. Duke's EE programs that were proposed separately were approved as of June 1, 2009 with all costs deferred. A modified save-a-watt regulatory model will be included in a rate case to be filed in the summer of 2009. A ruling is expected by the end of the year.	(See above)	(See above)
Texas	Texas state code specifies that a utility may be awarded a performance bonus (a share of the net benefits) for exceeding established demand reduction goals that do not exceed specified cost limits. Net benefits are the total avoided cost of the eligible programs administered by the utility minus program costs. The performance bonus is based on the utility's energy efficiency achievements for the previous calendar year. If a utility exceeds 100% of its demand reduction goal, the bonus is equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, up to a maximum of 20% of the utility's program costs. A utility that meets at least 120% of its demand reduction goal with at least 10% of its savings achieved through Hard-to-Reach programs receives an additional bonus of 10% of the bonus calculated.	Approved (2008)	PUC of Texas Substantial Rule §25.181(h); CenterPoint Energy Houston Electric 2008 Energy Plan & Report, Project No. 35440
Utah	HJR 9 was approved in March 2009 and includes language supporting incentives: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed but no mechanisms proposed	UT HJR009
Vermont	The operator of Efficiency Vermont, VEIC, is eligible to receive a performance incentive for meeting or exceeding specific goals established in its contracts. There is also a holdback in the compensation received by VEIC, pending confirmation that contractual goals for savings and other performance indicators have been achieved. The initial contract (2000-2002) allowed incentives of up to 2% of the overall energy efficiency budget over the three-year contract period. Incentives increased to 3.5% of the EE budget for the 2006-2008 period.	Approved (2000)	Contract 0337956, Attachment C
Washington	Puget Sound Energy's approved IRP for 2009 includes a shared savings ("Net Shared Incentive") mechanism that either rewards or penalizes PSE for exceeding or not meeting savings targets, respectively. The savings target for 2009 is 278,000 MWh, with a maximum incentive/penalty of $\underline{+/-}$ 50% and a "dead band" if the utility saves between 90-99.9% of the target. In addition to meeting the overall savings goal, PSE must meet at least 75% of the projected savings targets in both the residential and commercial/industrial sectors. 75% of the full incentive amount will be collected in the year after program implementation, with the remaining amount collected the following year.	Approved (2009)	WA Docket UE-060266

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Wisconsin	As of 2008, Wisconsin Power & Light (Alliant Energy) may earn the same rate-of-return on its investments in energy efficiency made through its "shared savings" program for commercial and industrial customers as it earns on other capital investments. Utilities may propose incentives as part of their rate cases, but there have been no proposals from other utilities under the most recent version of performance incentives. [Note: Wisconsin dropped performance incentives in the 1990s.]	Approved (2008)	Docket 6680-UR-114

Summary of Incentive Mechanisms

Approach	State
Earn a percentage of program costs for achieving savings target	CO, CT, RI, KY, MA, MI, MN, NH, RI, TX, VT, WA
Earn a share of achieved savings	AZ, CA, GA, OK
Earn a percentage of the NPV of avoided costs	NC, OH, SC
Altered rate of return for achieving savings targets	NV, WI

Note: Information was compiled using the latest public data available as of December 11th, 2009. Readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency. Other resources used in the preparation of this report were ACEEE's State Energy Efficiency Program Database, document s from EPA's National Action Plan on Energy Efficiency, and resources from the Regulatory Assistance Project.

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SMK-ER5-16

Energy Efficiency Incentives for Utilities: Approaches in US, Stakeholder Process in Idaho

Wayne Shirley, Jim Lazar and Lisa Schwartz

Webinar Convened by Idaho State Senator Elliot Werk

November 20, 2009

The Regulatory Assistance Project

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Regulatory Assistance Project

- Nonprofit organization founded in 1992 by experienced energy regulators
- Advises policymakers on economically and environmentally sustainable policies in the regulated energy sectors
- Funded by US DOE and EPA, the Energy Foundation, ClimateWorks and other foundations
- We have worked in 40+ states and 16 nations

Today's Webinar

- How sales and conservation affect utility profits
- Role of positive financial incentives for utilities in promoting all cost-effective energy efficiency
- Types of incentives, design features, pros and cons
- Idaho Power stakeholder process
- Principles for legislative actions

How Sales Affect Utility Profits Under Traditional Regulation

- Rates are set to recover the utility's cost of service
  - **Revenue requirement** = expenses + return of and return on investment + taxes (during past or future test period)
  - **Prices** = revenue requirement ÷ *expected* unit sales
- **Utility profit** = *actual* sales - *actual* expenses
  - In reality, profits have little relationship to the allowed revenue or rate of return set in the rate case.
- Increasing sales can increase profits. Conversely, reducing sales through energy efficiency programs reduces revenues to cover the utility's fixed costs, reducing its earnings.

Decoupling
Sales and Profits

- Decoupling is a ratemaking mechanism that breaks the link between energy sales and utility profits.
  - Rate case process remains the same
  - Prices are adjusted periodically, based on actual units sold, to keep utility revenue at its allowed level – no more, no less.
- The Idaho Commission approved a decoupling pilot for Idaho Power for 2007-2009. The company has filed a request to make decoupling permanent.
- Decoupling only removes the utility's disincentive toward energy efficiency; it does not provide an incentive.

Do Utilities Need Energy Efficiency Incentives?

- The energy efficiency program manager functions best with:
  - Clear performance metrics
  - Alignment of financial risks and rewards for those metrics
- Incentives make the manager squarely responsible for developing best program designs, partnerships and marketing strategies.
- Utilities have the opportunity to earn a return on supply-side investments. Absent an explicit incentive mechanism, they have little reason to invest in energy efficiency.*
- Shareholder incentives should be considered when energy efficiency programs are ramping up to high levels or to motivate a utility to continue performing at a high level.

**Except during prolonged periods of high market prices where the utility does not have an automatic power cost adjustment.*

Types of Positive Financial Incentives

- **Performance Based**
  - **Shared Savings:** Earnings based on percentage of "net" benefits (resource savings minus costs) or avoided costs of energy efficiency, often tied to a minimum threshold of energy and capacity savings
  - **Management Fee:** Earnings based on percentage of program costs if manager achieves or exceeds goals – e.g., energy/capacity savings, participation or installation levels, reductions in administrative costs
  - **Standard Performance Contracting:** Incentive payments per kWh and kW of savings from installed measures, under standardized terms
- **Cost Capitalization**
  - Annual energy efficiency program costs included in rate base and amortized over time; utility earns authorized rate of return on equity (ROE), potentially with a bonus ROE

Performance-Based Incentives

- **Pros**
  - Well-designed mechanisms can control utility expenditures by rewarding increased program penetration and minimizing costs
    - Net benefits increase when the utility achieves cost-effective savings and when project costs are reduced
  - Under management fee approach, utility has an incentive for energy efficiency spending
- **Cons**
  - Requires more analysis (determining net benefits)
  - For shared-savings mechanisms, accurate measurement and verification of savings is critical
  - Management fee approach does not necessarily focus spending on cost-effective programs and net benefits
    - Can address by basing incentive rates on carefully vetted and approved budgets, not expenditures, by adopting aggressive goals and clear performance metrics, and through good oversight

Cost Capitalization – With ROE Bonus Option

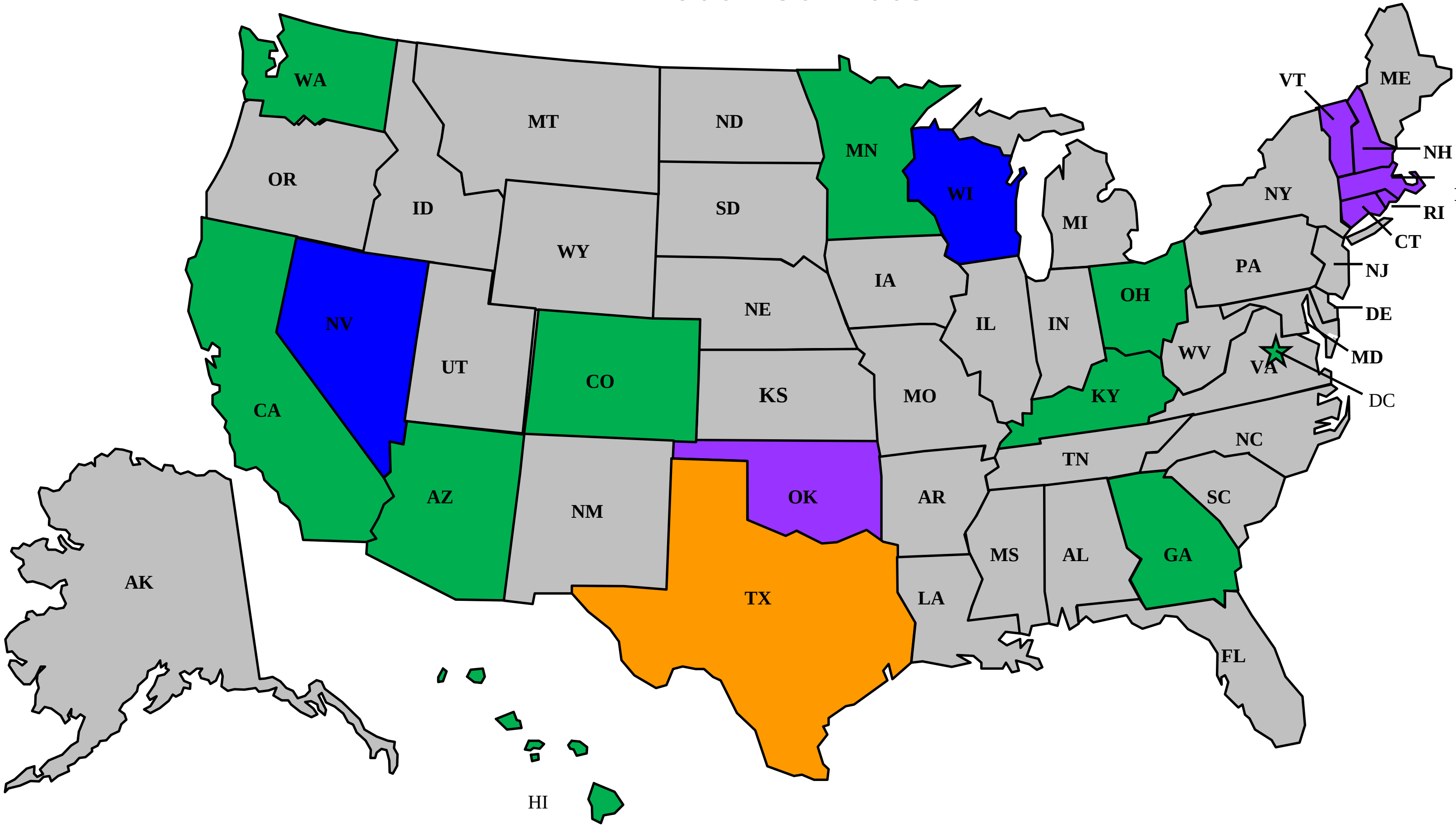
- **Pros**
  - Amortizing instead of expensing better matches cost recovery to the useful life of efficiency measures (7 to 10 years). Amortization period can be less (3 to 5 years).
  - Mitigates initial rate impacts of efficiency expenditures
  - Helps level playing field with utility-owned supply-side resources
    - But a power plant may still be more attractive to the utility
  - Can incorporate an ROE adder to make efficiency the most profitable investment
- **Cons**
  - Approach is generally out of favor among utilities (except in Nevada)
    - Don’t want a regulatory asset that increases imputed debt, potentially affecting credit ratings
    - Need capital to finance asset – must raise new capital or use retained earnings or internal cash flow
  - Incentive not tied to performance

A Couple of Ways to Measure Costs and Benefits

- **Utility Cost Test**
  - Measures cost-effectiveness purely from the perspective of utility expenditures compared to supply-side resource costs
- **Total Resource Cost**
  - Measures cost-effectiveness regardless of the split in costs between the utility (ratepayers) and program participants
- Some jurisdictions also include externality costs (those not captured by the market system)
- For both tests, the benefits are the avoided costs of supply-side resources – the reduction in energy, capacity, transmission and distribution costs.

EXAMPLES OF INCENTIVES IN THE U.S.

States With Energy Efficiency Incentives for Utilities*
November 2009



LEGEND

States with shared savings incentives for utilities or third-party administrators

States with a performance-based management fee

States that give utilities a return on investments in energy efficiency

States with performance-based contracting and a utility incentive for achieving goals

SMK-ER6-12

*Or incentives for the third-party energy efficiency administrator

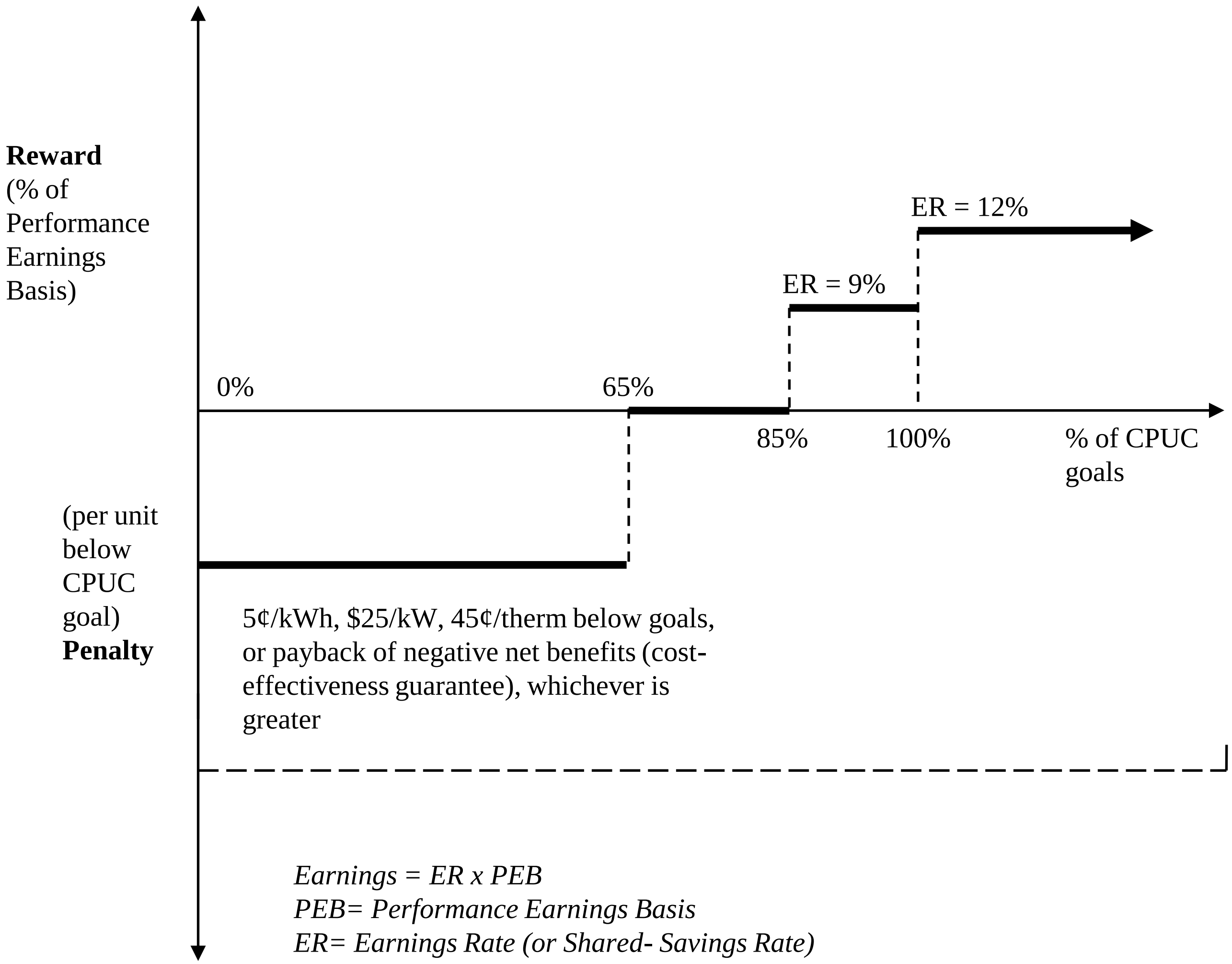
Shared Savings - Arizona Public Service Company

- Demand-side management (DSM) programs funded through base rates, plus adjustor for amounts over/under
- Incentive: 10% of net economic benefits achieved (benefits minus costs)
  - Capped at 10% of program spending

California Risk/Reward Incentive Mechanism

- Commission established savings goals for energy, demand and therms for three investor-owned utilities for 2006-08
  - Levels higher than had ever been achieved
- Incentives for achieving 85% of goals, based on average performance on all applicable measures
  - 9% to 12% of net economic benefits (total dollars capped)
  - No incentive if achievement is below 80% for *any* goal
- Penalties for failure to achieve at least 65% of goals
- Utility gets a portion of incentive after verification of actual *measures installed* and *program costs;* final incentive payment after verification of *savings*
- Program under review to "consider a more transparent, more streamlined and less controversial RRIM program"

California Risk/Reward Incentive Mechanism, 2006-2008



See California PUC D.08-09-043 at 8. Earnings and penalties are capped by utility:
PG&E - $180 million, SCE - $200 million, SDG&E - $50 million and SoCalGas - $20 million

Colorado

- HB 1037 (2007) directed Commission to offer utilities an opportunity to make demand-side management investments more profitable than other investments
  - By 2018, energy savings in aggregate must reach at least 5% of 2006 sales
- Commission rulemaking established performance incentives for natural gas utilities
  - Percent of net economic benefits = Energy Factor x Savings Factor
    - Energy Factor = Zero + 0.5% for each percentage of achieved savings > 80% of savings target
    - Savings Factor = Actual savings achieved ÷ the approved savings target (per $1 million expended)
  - *Example:* 15,000 dth savings target; utility at 106% of target (18,000 dth)
    - Energy Factor is 0.5% x (106 – 80) = 13%
    - Savings Factor is 18,000 ÷ 15,000 = 1.2
    - Percentage of net economic benefits = 13% x 1.2 = 15.6%

Colorado

- Public Service of Colorado performance incentive
  - 0.2% of net economic benefits for each 1% of goal attainment beyond <u>80%</u>, up to 10% of net benefits at <u>130%</u> of goal attainment
    - 4% of net economic benefits if <u>100%</u> of DSM goal is achieved
  - 0.1% of net economic benefits for each 1% of goal attainment beyond <u>130%</u>, up to 12% of benefits at <u>150%</u> of goal attainment
- Utility also gets a $2 million (after tax) "disincentive offset" each year it implements an approved demand-side management plan
- Cap: Performance incentive + disincentive offset cannot exceed 20% of total DSM expenditures

Minnesota Shared Savings

- Shared savings incentive since 2000 based on percent of net economic benefits
  - Minimum performance to earn incentive: 91% of savings goal
  - Percent of net benefits awarded increases with savings, capped at 150% of goal
  - Commission is exploring changes to program
- 2007 Next Generation Energy Act for natural gas and electric utilities
  - Achieve energy savings each year equal to 1.5% of retail energy sales by 2012
    - Includes end-use and market transformation programs, rate design, codes and standards, and utility infrastructure improvements
  - Commission may order submission of incentive plans for approval and must consider if the plan:
    - is likely to increase utility investment in cost-effective conservation
    - is compatible with the interest of ratepayers and other interested parties
    - links incentive to performance in achieving cost-effective conservation
  - Commission may:
    - Change allowed ROR on efficiency investment based on utility's efforts and success
    - Share between ratepayers and utilities net savings to extent justified
    - Adopt any mechanism that makes cost-effective conservation a preferred resource choice for the utility, considering impact on utility earnings

Nevada Bonus ROE

- Nevada law gives utility its authorized return on equity plus a 5% bonus for prudent and reasonable conservation and demand management investments
  - If utility's authorized ROE is 8%, energy efficiency investments earn 13%
- Statute also allows utility to request a bonus ROE for "critical facilities" such as reliability investments in the same manner

Management Fee for Vermont EE Utility

- Performance-based contract between Vermont Public Service Board and third-party “Energy Efficiency Utility,” currently the Vermont Energy Investment Corporation
- Contract includes performance-based goals
  - Cumulative annual electricity savings, peak demand savings by season and geographic area, total resource benefits, and specific program goals (e.g., increased measure penetration in certain business end uses)
- Incentives capped at 2.6% of total budget for 2009-2011
- Minimum performance requirements
  - Benefit/cost ratio, spending on residential and low income, program participation by small nonresidential customers, and geographic equity

Puget Sound Energy Conservation Incentive Mechanism - Washington

- Washington Commission sets energy savings targets annually
- Incentive for reaching the Baseline Target (100% of goal)
  - "MWh Incentive" *plus*
  - Shared Savings Incentive = Baseline savings target (MWh) * Net Shared Incentive ($10/MWh) * Shared Savings Rate (5%)
    - Shared Savings Rate is the percent of savings eligible for the incentive.
- Additional incentives for incremental savings
  - MWh Incentive = Incremental savings (MWh) * $20/MWh, *plus*
  - Shared Savings Incentive = Incremental savings (MWh) * Net Shared Incentive ($45/MWh) * Shared Savings Rate
    - Shared Savings Rate = 10% for savings between 100% and 110% of target
    - Shared Savings Rate rises incrementally to 100% at 150% of target – e.g., the rate is 20% for savings between 110% and 120% of target
- Penalties below 90% of target (penalties much larger than incentives)
- At least 75% of savings must be achieved in both the residential and commercial and industrial sectors

IDAHO POWER STAKEHOLDER PROCESS

Idaho Power Stakeholder Process Status

- Two workshops held
  - October 6: Educational on alternative incentive mechanisms
  - November 10: Focus on specific options for Idaho Power
- Final workshop scheduled
  - December 9: Attempt to reach consensus on framework, if not details

November Meeting: Narrowing of Options

- Shared Savings Mechanism
  - Symmetrical incentives and penalties
  - Progressive: Higher % shared savings as performance increases
  - Range of 0% to 15% of savings to company (plus cost recovery for measures and lost margin recovery through Fixed Cost Adjustment)
- Collaborative target setting (with IPUC final authority)
- Balanced performance between sectors required
- Still examining whether incentives should be based on Total Resource Cost (societal savings) or Utility Cost (utility-system only savings)

November Meeting: Narrowing of Options

- Timing of incentives
  - A portion in first year after measures installed; balance after evaluation
- Measures included initially
  - Only those for which utility operates programs
- Evaluation and measurement
  - Utility retains contract with oversight from stakeholder collaborative

Idaho Power Stakeholder Process: Next Steps

- December 9th stakeholder meeting in Boise
- Modeling of options discussed in November to be presented by Idaho Power
- Attempt to reach resolution on:
  - Level of incentives
  - Collaborative structure
  - Evaluation approach
  - Implementation issues

Principles for Legislative Actions

- Setting savings goals for energy and demand
- Ensuring authority and flexibility for the Commission
  - To adopt the most appropriate mechanism
  - To rate-base DSM investments using a shorter amortization period than the life of the measures
  - To make efficiency a competitive investment
  - To use the Total Resource Cost test to determine net benefits
  - To decide whether savings beyond efficiency programs for customers can be included (e.g., codes) to align utility and customer interests
- Addressing extra-jurisdictional gaps for unregulated utilities
- Addressing programs for low-income households
  - Minimum spending levels or higher incentives

Resources

- National Action Plan for Energy Efficiency, *Aligning Utility Incentives with Investment in Energy Efficiency*, prepared by Val R. Jensen, ICF International, November 2007, at http://www.epa.gov/cleanenergy/documents/incentives.pdf.
- Peter Cappers, Charles Goldman, Michele Chait, George Edgar, Jeff Schlegel and Wayne Shirley, *Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility*, Ernest Orlando Lawrence Berkeley National Laboratory, March 2009, at http://eetd.lbl.gov/EA/EMP/reports/lbnl-1598e.pdf and http://eetd.lbl.gov/EA/EMP/reports/lbnl-1598e-app.pdf (appendices).
- Peter Cappers and Charles Goldman, *Empirical Assessment of Shareholder Incentive Mechanisms Designs Under Aggressive Savings Goals: Case Study of a Kansas "Super-Utility,"* Ernest Orlando Lawrence Berkeley National Laboratory, August 2009, at http://eetd.lbl.gov/EA/EMP/reports/lbnl-2492e.pdf.
- Michael W. Rufo, Itron Inc., "Evaluation and Performance Incentives: Seeking Paths to (Relatively) Peaceful Coexistence," Proceedings of the 2009 International Energy Program Evaluation Conference, Aug. 12-14, 2009, pp. 1030-1041, at http://docs.cpuc.ca.gov/efile/CM/106837.pdf.

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