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Making a Business of Energy Efficiency: Sustainable Business Models for Utilities

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I. EXECUTIVE SUMMARY

A. Context

Today, energy efficiency is at the forefront of energy policy.[1] Concern about global climate change and the environment, combined with rate pressures from the need to build expensive baseload generation plant and to recover fluctuating fuel prices, has brought the issue of energy efficiency front and center with utility executives, regulators, and public-policy advocates. Energy efficiency is again in the public limelight, and utilities are increasingly being called upon to adapt their business models to incorporate the provision of cost-effective energy efficiency.

This is not the first time that energy efficiency has been at the forefront of public policy, nor is it likely to be the last. The price pressures from the oil disruptions in the ’70s and early ’80s certainly brought the issues of conservation and energy efficiency to the forefront. In the early ’90s, many utilities and state regulatory commissions also promoted energy efficiency through the mechanism of least-cost planning. In fact, the National Association of Regulatory Utility Commissioners (NARUC) in the early ’90s adopted a resolution that called for the utility’s least cost plan to be the utility’s most profitable plan. These policies promoted energy efficiency as a resource that should be on an equal footing with building or buying new power plants.

In the course of working with customers and regulators, many utilities promoted energy efficiency, and some did so quite aggressively. Those who aggressively promoted energy efficiency were generally in states where regulators adopted special rate treatment mechanisms, the effect of which was to remove many, if not all, of the disincentives that limited the attractiveness of utility investment in energy efficiency and demand side management as a resource.[2]

However, almost all of the aggressive energy efficiency programs and the innovative rate mechanisms vanished in the late ’90s. There were three primary reasons that appear to have caused their decline. First, the ’90s represented an era of broad-based privatization and deregulation around the world, which manifested itself in the desire to harness markets and private incentives instead of pursuing social policy on the backs of infrastructure industries (through either ownership or regulation). Second, restructuring efforts led many utilities to be focused on reducing the cost of their service, while at the same time restructuring allowed competitive markets and energy service companies to step in for utilities and provide energy efficiency where economic to do so. Third, utility investment in energy efficiency may have been pursued even though it resulted in rates higher than they would otherwise have been. In some cases, programs may not have met a “no-losers” test, meaning that customers who did not participate in these programs may have experienced higher rates. In those cases, the pressure often became significant enough to scale back the programs. Restructuring also led to a surge in the amount of generation capacity, and thus, the near-term need for development of energy efficiency resources was diminished. The disappearance of large-scale energy

[1] The National Action Plan for Energy Efficiency Report defines energy efficiency as “using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term energy efficiency as used here includes less energy at any time, including at times of demand through demand response and peak shaving efforts.” See: U.S. Department of Energy and U.S. Environmental Protection Agency, National Action Plan for Energy Efficiency, July 2006, http://www.epa.gov/cleanenergy/actionplan/report.htm (Accessed March 12, 2007).

[2] Absent special rate treatments there are both incentives and disincentives to utilities promoting energy efficiency. When energy efficiency can defer large capital expenditures that pose financial risks, utilities have a strong long-term financial incentive to promote efficiency that can outweigh any short-term financial disincentive.

efficiency programs resulted in the loss of energy efficiency infrastructure – energy efficiency providers failed, staff left the industry, and some customers soured on efficiency investments as a result of unmet promises.

In today's environment, when public pressure is again forcing energy efficiency to the forefront, the authors believe it is important to think about the historic experience with energy efficiency. Energy efficiency is too important to the long-term economic health of the country to be given short shrift. And the on-again, off-again commitments to energy efficiency have done much to damage customers' trust in providers of energy efficiency.

Thus, it is the aim of this report to discuss utility business models for energy efficiency with a particular eye towards their sustainability.

B. Purpose and Objectives of the Project

The Edison Electric Institute (EEI), a trade group representing investor-owned utilities, recognized the reemergence of energy efficiency and retained NERA Economic Consulting to conduct a study of utility energy efficiency business models. Building on previous work conducted by NERA for EEI,[3] this study aims to review utility business models for energy efficiency to:

- Set the context for the strategic and financial challenges likely to be encountered by utilities as they confront the current public policy and regulatory environment,
- Establish a strategic framework for how utilities might think of the business model implications of the current environment,
- Build upon other work on business models,[4]
- Identify the business and revenue models that utilities might employ and the regulatory challenges they may present, and
- Characterize the financial impacts of the possible business models.

This report solely reflects the opinions of the authors and not of NERA as a whole.

C. Criteria for Economically Sustainable Business Models

As noted above, we are particularly interested in identifying sustainable business models. To be economically sustainable, business models must meet several criteria:

- The business model must result in meaningful return to the utility – that is, it must be in the utility's interest to be in the business, and there must be market demand for that business;
- The business model must survive the cycles of political and public favor;

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[3] *Distributed Resources: Incentives*, by Eugene T. Meehan and Wayne P. Olson, NERA white paper prepared for the Edison Electric Institute, May 31, 2006.

[4] Other studies include the EPA/DOE *National Action Plan for Energy Efficiency*, the October 2006 ACEEE report, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives," and the September 2006 EPRI study, "Business Models and Regulatory Templates," among other recent and ongoing efforts in the overlapping arenas of energy efficiency, demand response (DR), utility business models, and related regulatory frameworks.

- There must be a compelling reason that the utility is involved in the delivery of energy-efficiency-related services; the utility must bring expertise or a unique position in the value chain to justify its involvement in energy efficiency; and
- The business model must mesh well with the regulatory models used in the jurisdiction.

This country's on-again, off-again pursuit of energy efficiency has roiled the development of the energy efficiency industry. In the late '80s and early '90s, many firms entered the market to promote energy efficient technologies and to see them implemented in our nation's businesses and residences, only to see the market vanish when utilities and regulators lost interest in energy efficiency. While it is certainly possible to attract a utility's interest in promoting energy efficiency through altering the regulatory mechanisms used to set rates, such changes may not lead to the conditions for a long-term sustainable business in energy efficiency. Thus, the quest for an appropriate business model should consider the durability of the business model itself – is it only transitory (e.g., while the regulator has interest), or is it a business model that is durable and will continue to be viable as long as there is market demand?

Similarly, there must also be a compelling reason for the utility to be involved in the provision of energy efficiency services. Utilities have many advantages that may position themselves well in this regard – after all, they often are the most trusted of energy advisors, and have great knowledge of energy technologies, costs, and applications – but if the business model devolves to no clear compelling reason for the utility to be involved, there are likely more efficient methods to advance energy efficiency.

D. Drivers for Energy Efficiency

The key drivers for energy efficiency are as follows:

- **Increasing Rates** — from expiring rate caps, commodity prices, and new investment – mean that customers need mechanisms to control their bills, and energy efficiency programs provide an important means of control.
- **Environmental Concerns**, including the potential of greenhouse gas control, increase the need for energy efficiency programs.
- **The Need for Substantial Infrastructure Investment** — the industry is facing continued growth in demand which will necessitate increased investment in generation and transmission facilities. Cost-effective energy efficiency efforts can play a significant role in reducing or delaying the level of infrastructure investment that will be required.
- **New Technology** — Technology is now a key enabler of better meeting the needs and desires of customers.

None of these drivers is likely to go away in the near- to mid-term and, indeed, there is every likelihood that they will intensify.

Most importantly, regulators, legislators, interveners, and the public want utilities to play a leading role in energy efficiency.

- **Environmental groups and efficiency advocates** are petitioning public policy-makers for accelerated implementation of energy efficiency programs.
- **Regulators and legislators** are also looking for ways to provide customers with tools to control their escalating bills.

- **Utilities are natural institutional means to deliver energy efficiency.** Utilities can act as aggregators of consumer demand and create positive system benefits through energy efficiency programs.

E. The Families of Business Models

Consideration of the energy service value chain suggests that a utility could choose to occupy several different value chain positions, meaning several strategic architectures appear to be possible. While a number of "families" of business models might be possible, we have chosen to focus on three to represent the range of possibilities available to utilities.

- **Conventional Regulatory Incentives Family** – This family uses regulatory mechanisms that historically have been adopted to promote energy efficiency investment by utilities. Each business model has a specific mechanism to address the throughput issue,[5] a specific mechanism to recover the energy efficiency program costs and a positive shareholder incentive to encourage utility promotion of energy efficiency. This family encompasses two specific business models, which will be detailed in Chapter IV of this report:
  - Shared Savings Business Model.
  - Capitalization Business Model.
- **Performance Model Family** – Through a long-lived Performance-Based Regulation (PBR) plan, the utility shares savings arising from implementation of energy efficiency. PBR mechanisms—tailored to energy efficiency issues—could include multi-year versions of the conventional regulatory incentives. We provide a specific example of this business model in Chapter V of this report.
- **Energy Services Model Family** – The utility (or an affiliate) directly sells services to customers on a fee-for-service model, which allows utility shareholders to profit from the provision of ESCO-type services. This family encompasses three specific business models, which will be detailed in Chapter VI of this report:
  - Customer Infrastructure Business Model.
  - Fee for Service Business Model.
  - Green Power Business Model.

All six business models are potentially applicable to all major utility types (vertically integrated, wires only, and non-regulated) **except** that Conventional Regulatory Incentives and Performance models are **not** applicable to non-regulated entities.

Most likely, the approach that a utility will adopt will be some mixture of the above strategies. Potential strategic architectures encompass both regulated and non-regulated characteristics and elements. Moreover, potential strategic architectures will reflect not only a company's strategic choices, but also—critically—the regulatory constraints within which the company must operate. Thus, available or appropriate strategic

[5] The throughput issue arises under traditional rate making process because most rate structures do not set their rates on the basis of marginal cost, but rather generally load some or a significant amount of margin into the energy rates. As a result, a utility that promotes energy efficiency by its customers loses, in the short term, margin on every unit conserved. The mechanisms used to address throughput include rate design (e.g., ensuring that the tail rates reflect marginal cost), lost margin recovery mechanisms, and decoupling mechanisms.

architectures will vary not only with type of market participant (e.g., integrated vs. not, largely regulated vs. not), but also by jurisdiction and market.

These models represent a range of options for utilities and regulators to consider in thinking about energy efficiency. They also represent a continuum in sustainability as well. The Conventional Regulatory Incentives group of models are the least likely to be sustainable, as they rely upon the continuity of regulatory favor for their sustainability. These models are most likely to be adopted with aggressive implementation of large scale energy efficiency programs; as a result, they likely have the largest rate impacts on non-participants. The experience with these mechanisms suggests that they *do* change utilities' interest in promoting energy efficiency, but they also often lead to the creation of regulatory assets, customer and consumer advocate pressure to end or substantially reduce the energy efficiency programs, and ultimate reduction of the energy efficiency business.

The Performance Model family is more sustainable, as it is predicated on a long-lived agreement with the regulator and on providing greater flexibility to utility management. However, this family of models still relies upon the periodic review of regulators, and there is no assurance that energy efficiency will remain an important issue at the time of those reviews.

The Energy Services Model family is the most durable, as it looks directly to customers for its implementation. While this family may have regulatory risk, these issues generally can be averted by implementing the model through an affiliate.

The three families of business models will be discussed further in Chapter III of this report.

F. Conclusions

Although it is difficult to distill a small number of universally applicable conclusions in the broad, complex, and rapidly evolving arena of energy efficiency, some conclusions are in order:

- The most durable and sustainable business models require significant change in either the regulatory framework or the utility's orientation to service delivery – while the amount of change is not to be underestimated, circumstances indicate that these changes are more feasible today than previously.
- There are transition paths to the more durable models – they need not be implemented in a single leap, but rather through an orderly transition.
- Without significant change to the business models, energy efficiency will continue to follow a path of "hot today, not tomorrow."
- Perhaps the central question is, Can a utility engage in energy efficiency lines of business and make money doing so? The results of this project clearly point to a simple answer: Yes. But doing so depends on a variety of regulatory and business circumstances, such as:
    - For some utilities, the immediate model may involve innovative application of traditional regulatory tools.
    - Other utilities may want to look to models that involve substantial regulatory change, but offer greater flexibility to the utility.
    - Some utilities may look to implement models that are more market-oriented in their development and deployment of energy efficiency resources.
    - Some utilities may want to start simple and pursue more complex business models over time.

II. SUSTAINABLE BUSINESS MODELS

A. What is a Business Model?

In this report, a business model represents a *method* of generating revenues and profits for shareholders by offering for sale some set of products or services.[6] On its face, this is a very straightforward concept. Any company that is attempting to generate revenues and profits by selling a set of products or services can be said to have a business model. Further, a business model may encompass multiple product and service offerings; simply offering multiple products (e.g., Coke and Diet Coke) does not constitute multiple business models. There are many ways that energy efficiency services can be provided within any one business model—what comprises different business models is the method by which revenues and profits are generated and the way in which the company's value proposition to customers is organized.

In the context of utility service, this simple understanding of a business model masks a range of complexity in what various stakeholders view as business models. In our interviews with senior members of a number of utilities, we found that the concept of a "business model" with regard to energy efficiency included different ideas. Some interviewees believed that energy efficiency was part of their "regulatory" model and that it was primarily about the rate treatment energy efficiency programs received. They did not view even the language of a business model as particularly helpful. Others viewed the relevant business model as the way in which the overall utility itself operated with energy efficiency services being just a customer service oriented offering within their overall business of generating revenues through sales of electricity. Still others indicated that the business models for energy efficiency were the very specific set of services that were offered as stand alone products or services with their own revenues and costs.

To evaluate alternative business models, it is important to see the dimension on which business models may vary. A business model can be characterized by a number of key elements including the following:

- *Value Proposition.* This is the reason a customer will choose to purchase your services. It includes the nature of how one creates value for customers and why one's offerings are superior to others. For retail customers with traditionally regulated utilities, this primarily means delivering reliable power cost-effectively. With regard to energy efficiency, it may mean delivering lower energy bills, greater comfort, control over your bill, reduced environmental impacts, and greater reliability depending on the nature of the business model.
- *Revenue Model and Rate Treatment.* This is the process by which revenues are collected for the services being offered. It also includes the cost and profits generated by the business model. For utilities focused on energy efficiency, this might mean collecting revenue as part of rates or offering added services for a fee.
- *Customers and Services.* These are the specific products or services that are being offered and to whom they are offered. Energy efficiency is not a product per se. It is an attribute embedded in a bundle of activities that can be offered. For example, a firm could weatherize one's home, which would increase one's comfort while reducing your energy bill. The service provided is weather stripping, which has the attribute of resulting in your home becoming more efficient in using energy.

[6] This concept of a business model can also apply to municipal or public authorities that may offer products or services for sale although they do not have the same orientation toward evaluating costs and profits.

How this attribute—energy efficiency—is bundled into a utility offering helps differentiate business models.

- *Key Competencies.* This factor describes the capabilities or competencies required by the business to effectively execute the value proposition and revenue model. It is important in the discussion of energy efficiency because some business models require different competencies than others in delivering products or services that have energy efficiency embedded in them. For example, many utilities are very effective at offering regulated energy service and regulated energy efficiency programs, but they may be less successful offering unregulated fee-for-service energy efficiency programs.
- *Scale, Scope, and Timing.* These factors represent the level of resources and assets needed to execute the value proposition and revenue model and how these factors need to change over time to sustain the business model.
- *Risk Factors and Durability.* These are the primary factors that put the value proposition and revenue model at risk to be changed, preempted, or engulfed by external or competitive forces. These factors are important because there will be considerable debate over what makes various approaches durable in the current environment, which includes a heightened interest in environmental issues, uncertain rate impacts of new utility investments, and varying assessments of what is cost effective.
- *Regulatory Issues and Constraints.* Regulatory treatment is important in evaluating any business model, but it is particularly important in the context of utilities and energy efficiency. Key regulatory factors and constraints are those that impact the value proposition or revenue model and its sustainability over time.

In the next Chapter, we use these dimensions as a basis for evaluating the alternative approaches to building sustainable business models around energy efficiency.

B. What is a "Sustainable" Business Model?

If energy efficiency is to be a key component of the utility industry and increasingly incorporated into the national energy supply picture, the business models that incorporate energy efficiency must be sustainable. Sustainability has two key connotations in this debate that need to be understood. In general, "sustainability" refers to a business model operating in an environment in which the basic revenue model and value proposition are durable across time. In this sense, the viability of sustainable business models is not undermined by short-term fluctuations in customer needs, technological innovation, regulatory factors, or competitor actions. While there are often business propositions or business models that result in profits and customer benefits for short periods of time (pop rocks, for example), the longevity of the opportunity is limited by some factor. For example, the presence of a tax credit for particular technologies may make investing in certain activities profitable over the period of time that the tax credit exists. But one would not necessarily describe that as a sustainable business model to the extent that it lacks the requisite conditions for the revenue model and value proposition to be sustained over a lengthy period of time.

There is a second connotation of "sustainable" business models which is also found in the discussion of energy efficiency. Sustainability is used in an environmental context to refer to business models that help lead in some way to smaller environmental impacts. Thus, energy efficiency, demand response, alternative fuels, distributed generation, and similar activities may be viewed as part of a portfolio of programs or service offerings that reduce the environmental externalities of the electricity system and therefore lead to more "environmentally sustainable" business models.

The two views on sustainability are not mutually exclusive, but they are not identical either. There are business models which are sustainable in an economic sense that would not qualify as sustainable in an environmental sense by those evaluating the model. The reverse is true as well. For many, the goal is to find the appropriate alignment of these two views of sustainability.

The current debate over the appropriate role for energy efficiency activities is substantially affected by the question of sustainability. Energy efficiency programs have all been part of the energy industry for decades. The interest in these activities in many parts of the country has ebbed and flowed with broader public policy debates over energy strategies like energy independence, industry restructuring, demand growth and the need for new capacity, environmental issues, and response to customers' concerns about their energy bills. In other areas of the country, the investment in energy efficiency activities has been relatively stable and less subject to wide swings in investments, types of programs, and public interest. But despite more than 30 years of experimenting, testing, rolling out, and in many cases discontinuing programs and offerings by utilities, utility affiliates, innovative start-ups, large energy industry players, and government sponsored business initiatives, no single framework for the determining and defining the appropriate sustainable mix (from the business model view of sustainability) of energy efficiency activities has emerged.

For our discussion in this report, we are focused primarily on *economic* sustainability. To be economically sustainable, business models must meet several criteria:

- The business model must result in meaningful return to the utility – that is, it must be in the utility's interest to be in the business, and there must be market demand for that business.
- The business model must survive not only cycles in market demand, but the cycles of political and public favor, and lead to long-term investment in these activities.
- There must be a compelling reason that the utility (as opposed to some other market actor) is involved in the delivery of energy efficiency services; the utility must bring expertise, resources, or a unique position in the value chain to justify its involvement in energy efficiency.
- The business model must mesh well with the regulatory models used in the jurisdiction.

To evaluate a given business model these criteria must be weighed against many factors that affect the likely long-term success of a given approach for a given company.

C. What Factors Drive the Evaluation of Sustainable Business Models in the Utility Industry?

Whether particular business models will be sustainable over time depends on many factors, some that individual companies control and some that they do not control. By conducting our senior level interviews for this project, we found a range of factors that executives felt were important to understanding their current evaluation of various business models for energy efficiency investment. These factors affected their assessment of various business models and whether those business models are viewed as relevant or desirable. Key factors included:

- Whether the utility is wires-only or vertically integrated with generation,
- The degree of environmental issues,
- Whether rates are currently considered high or low,
- The degree to which rates are rising slowly and incrementally versus the degree to which rates are likely to rise dramatically. This, in turn, reflects:

- The amount of expected investment in the transmission and distribution (T&D) system,
- The degree to which jurisdiction is generation capacity-constrained or facing an overcapacity of generation,
- The degree of volatility in fuel costs,
- Impacts of rate caps or removal of caps, and
- The stability of historical investment/regulatory mechanisms in energy efficiency.

These factors will be considered in the evaluation and discussion of each of the business models enumerated below.

D. Overview of Families of Energy Efficiency Business Models

A key objective of this report is to review the various approaches to building energy efficiency business models with an eye toward evaluating their sustainability. Based on our review, three families of business models, and six specific business models within them, were identified. They are distinguished as "families" of models in that they offer three different broad platforms for understanding the logic by which there can be both growth in the investment in and delivery of energy efficiency and the potential for the growth to be sustainable given the criteria established for a sustainable business model. Within each family, there are some variations on the platform that deserve consideration. Hence, six individual business models are described. In this Chapter, there is brief overview of the families and models. More detailed discussion follows in subsequent Chapters, each devoted to a particular family of business models.

1. Family 1: Evolution of Conventional Regulatory Incentives

One approach that we viewed as a distinct family of business models is to build on the traditional utility business model involving conventional cost of service regulation, but expand the use of special-purpose regulatory mechanisms for energy efficiency. This approach is favored in a range of jurisdiction where integrated utilities are the primary providers of energy service to the retail markets and it provides a great deal of flexibility in the construction of the specific mechanisms.

In this approach, combinations of cost recovery, throughput mechanisms, and positive shareholder incentives are used to remove disincentives and to go beyond that by providing positive incentives that encourage utility promotion of energy efficiency. A cost recovery mechanism, either some type of tracker or deferral accounting, is used to collect the direct energy efficiency costs The throughput issue can be addressed through marginal-cost-based rate design, a lost margin recovery mechanism (either tracker or deferral accounting based), or a decoupling mechanism (e.g. ERAM, PRAM).

A positive shareholder incentive can take the form of a share of the net benefits created, ratebasing of a portion of the energy efficiency expense with a higher ROE on the capitalizable cost for energy efficiency, or performance-based incentives.

2. Family 2: Performance Based Regulation Mechanisms

A second distinctive family of approaches centers on Performance Based Ratemaking Mechanisms. In these models, a long-lived Performance-Based Ratemaking (PBR) plan is designed in which the utility pockets savings relative to revenue arising from implementation of energy efficiency programs. The logic for this family contrasts with the first family of models in that Family 1 relies on paying the utility to promote energy efficiency through special mechanisms, whereas this family allows the utility to capture cost savings arising

from energy efficiency for the duration of the rate plan. In effect, PBR plans can include multi-year versions of the very same regulatory mechanism used in Family 1. During the term of the plan, the utility would internalize the costs of service delivery and makes the "right" (i.e., most economically efficient) buy, build, conserve, or shift decision.

3. Family 3: Energy Services Family

The third family of models shares as its logic the notion that energy efficiency services can be sold directly to retail customers on a fee-for-service basis. That is, customers who desire or see value in additional expenditures for energy efficiency service (whether to lower bills, increase comfort, express green preferences, or other benefits) can be offered those services on a fee-for-service basis. This is different from Family 1 in that there are fewer issues with cross subsidization and rate impacts on non-participants. This is different from Family 2 in that there is no need to develop future revenue/cost caps. This family creates a close alignment between the utility's and customer's incentives and these models are less sensitive to the ebb and flow of regulatory interest in energy efficiency, thus creating a more sustainable environment for growth in these services over time.

At the same time, there are several issues with these models that need to be addressed. First, because of competition concerns, some stakeholders might argue that the utility may not be the best provider despite its relationship with the customers. However, utility participation in energy services on a non-core, below-the-line basis can provide a valuable alternative to customers, which may be needed to realize fully the potential benefits of energy efficiency.

Second, in many markets where rates are low and relatively stable, the demand for these services may not be large enough to justify the cost of creating and maintaining programs to exploit these markets. Third, the profit margins on these services (assuming no subsidization) may be lower than the rate of return earned by utilities in traditional ratemaking and thus there may be little incentive for utilities (or utility affiliates) to enter lower return businesses that may involve significant risks.

III. CONVENTIONAL REGULATORY INCENTIVES FAMILY (FAMILY 1)

The first family of business models builds on the traditional utility business model involving conventional cost-of-service regulation, but expands the use of targeted, special-purpose regulatory mechanisms that address utility incentives to pursue energy efficiency. In this approach, combinations of cost recovery, throughput mechanisms, and positive shareholder incentives are used to encourage utility promotion of energy efficiency.

Because small changes in demand can have large financial implications for a utility (please see sidebar example), the primary task when implementing regulatory incentives for energy efficiency programs is to assure the utility that these programs will not have an adverse effect on the utility's financial position. There are three aspects of financial incentives that must be addressed: recovery of the costs the utility incurs in promoting energy efficiency, staying whole for fixed cost recovery that typically results from sales reductions (the throughput issue), and some financial incentive to ensure that energy efficiency is more profitable.

> For example, consider a utility with $100 in revenue and $10 in profits (10 percent ROE) that implements a program that reduces per customer consumption by 5 percent. Revenues decrease proportionally according to the utility's rate design. If approximately 80 percent of revenues is derived from usage charges (as opposed to a monthly per-customer charge), implementing this program implies a loss of $4 in revenue. If the entire loss is passed through to the utility without a cost recovery mechanism and with little or no reduction in marginal production costs, this program could result in a $4 (40 percent) loss of profit.

A cost recovery mechanism, either some type of tracker or deferral accounting, is used to collect the direct energy efficiency costs. The throughput issue can be addressed in several ways including: rate design, a tracker or a decoupling mechanism.[7] A positive shareholder incentive can take the form of a share of the net benefits created, ratebasing of a portion of the energy efficiency expense with potentially a higher ROE on the capitalizable expense for energy efficiency, or performance-based incentives.

There are two identified models in this family, differentiated by the nature of the shareholder incentive provided: the Shared Savings Business Model (referred to as Model 1a) and the Capitalization Business Model (Model 1b). Each is described and evaluated in more detail below.

A. Shared Savings Business Model (Model 1a)

In the first model, utilities are paid a share of the net benefits for undertaking energy efficiency efforts. The shareholder incentive is based on a defined share of net benefits measured by an agreed cost-benefit measure. A cost recovery mechanism and way to address the throughput issue may also be used. This model most closely aligns utility's incentives with the interests of the regulator (and presumably customers – at least as long as the net benefit measure reflects the welfare of consumers). The utility has an incentive to find the

[7] A decoupling mechanism is a way to sever the link between utility sales and profits.

most cost-effective energy efficiency since that will generate the greatest net benefits (and shareholder incentive) and it provides assurances of cost recovery.

Since the utility is paid for the net benefits produced, it has the incentive to find the most cost-effective resources available (i.e., those with the greatest net benefits). Often, utilities were paid on the basis of planning estimates of savings when starting these types of incentive plans, but they generally transition to payment based on the measured savings. This means that the utility will have some risk in its shareholder incentive.

More specifically, the key elements of this business model are as follows:

- *Value proposition*: Utilities are paid a share of the net benefits for undertaking energy efficiency. The utility's interest is aligned with customers' interest by paying the utility a meaningful portion (say 10 percent) of the net benefits produced.
- *Revenue Model and Rate Treatment*: The utility is paid on the basis of demonstrated net benefits produced. The shareholder incentive is based on a defined share of net benefits measured by an agreed cost-benefit measure. Cost recovery occurs through a tracker or deferral mechanism. The throughput disincentive is handled either through marginal cost based rate design, lost margin mechanism, or a decoupling mechanism.
- *Customers and services*: The specific product or service offering can be structured in a variety of ways under this model. The primary characteristic of the product or service is whether its benefits are directly measurable in an unambiguous manner. Similarly, there are few, if any, limits on which customers can be targeted under this model.
- *Required competencies*: Utility knowledge of costs; experience in design, implementation, and evaluation of energy efficiency programs; knowledge of customers and the network and regulatory relationships.
- *Scale/scope/timing*: Business models of this type are in use now and can be fine tuned for additional energy efficiency goals. The primary limit is the tolerance to accept various levels of rate impacts.[8]
- *Risk to sustainability*: Risks include measurement and evaluation risk and rate impacts. Complexity of measurement and evaluation can limit the attractiveness of the model. Regulators may decline to reward a utility for efficient practices. Durability of this model is dependent on customer reactions to rate impacts, the public policy interest in societal benefits of energy efficiency, and the policy debate on the role of the utility in delivering these benefits.
- *Enabling policies*: Definition of net benefits, measurement of impacts, determination of the savings share, throughput mechanism, and cost recovery mechanism, regulatory approval of what, how much, and when. In addition, legislative action may be needed to enable the mechanisms and offerings of the utility. Finally, legislation requiring the regulatory commission to adhere to a specific set of regulatory mechanisms may improve the sustainability of this model.
- *Circumstances under which utilities would likely adopt the model*: Utility and regulator want to closely align the interests of the utility and the customer.

[8] Note that there may be potential indirect benefits to non-participants, since demand response and energy efficiency can improve the entire electrical system's performance during peak period by reducing the costs associated with meeting high demand levels. See: "Retail-Load Participation in Competitive Wholesale Electricity Markets," prepared by Eric Hirst and Brendan Kirby for the Edison Electric Institute and Project for Sustainable FERC Energy Policy, January 2001.

There are a variety of illustrative examples of this type of business model in application. For example, prior to implementing retail competition in 2000, California used a shared savings mechanism, in which utilities received revenue equal to a portion of the savings value produced by their energy efficiency programs. Hawaii also had a shared savings model in place for many years.

A good example is the DSM Incentive Mechanism approved for Northern States Power Company.[9] In addition to DSM cost and lost margin recovery, the Company can earn 10 percent of the incremental net benefits of DSM projects that exceed project goals. Conversely, if the Company develops projects that realize less than 75 percent of the savings goal, it is assessed a penalty. Bonuses are capped at 120 percent of project goals.

B. Capitalization Business Model (Model 1b)

In the second model in this family, the Capitalization Business Model (Model 1b), utilities are paid for undertaking energy efficiency activities by capitalizing and earning a return on the energy efficiency costs. The shareholder incentive is based on a capitalization policy (i.e., deferral accounting treatment) in the jurisdiction; possibly an increased ROE or performance-based rewards can be negotiated. As with Model 1a, a cost recovery mechanism and a way to address the throughput issue would also be used. Because this business model insures that utilities recover their costs with a reasonable rate of return, utilities will not have an incentive to discontinue the program if it is not cost effective for ratepayers. Thus, it is imperative that regulators investigate and approve only those energy efficiency programs that are cost effective.

The key elements of this model are as follows:

- *Value proposition*: The utility capitalizes a portion of its energy efficiency costs and earns a return on it. The utility is encouraged to pursue energy efficiency by treating demand-side and efficient resources just like any other investment made by the utility for the benefit of ratepayers.
- *Revenue Model and Rate Treatment:* The utility is paid on the basis of the capitalized expense times the allowed ROE. The shareholder incentive included capitalization of energy efficiency expenses with potentially a higher ROE. Cost recovery of non-capitalized energy efficiency expense would occur through a tracker mechanism. The throughput disincentive is handled through either marginal cost based rate design, lost margin mechanism, or a decoupling mechanism.
- *Customers and services:* The energy efficiency offerings can take several forms, but the utility may have an incentive to favor offerings that involve equipment or other capital-intensive options. This may be important where new technologies, such as communications infrastructure with customers, are part of the offering. There are very few limits on target customers.
- *Required competencies:* The required competencies are the same as Shared Savings business model (1a), but may not require as much of a focus on measurement and evaluation.
- *Scale/scope/timing:* This model is in use in some jurisdictions with the primary limits being rate impacts and regulators willingness to consider the capitalized investment as key to the energy efficiency offering.
- *Risk to sustainability*: Risks include rate impacts and the continued need to demonstrate the effectiveness and reasonableness of the results of the energy efficiency programs. Economically inefficient programs exacerbate rates and would lose political support quickly—a continued

[9] See: Minnesota Public Utilities Commission, Order Approving Demand-Side Management Incentive Mechanism, Docket No. E-002/M-95-1005, March 11, 1996.

commitment by the utility to pursue economically efficient projects with minimal rate impacts would be needed. Durability is comparable to the Shared Savings business model.

- *Enabling policies:* The key issues for implementation are the capitalization rules, ROE allowed on the capitalized expenses, design of cost recovery and throughput mechanism, regulatory approval of what, how much, and when.

This model will tend to be favored where the utility and/or regulator are more comfortable with a model that resembles traditional rate-of-return regulation. This model may also rely less on measured results.

There are a number of examples of this model, including the following:

- In 2001,[10] the Hawaii PUC promulgated guidelines that permitted Hawaiian Electric Company, Hawaiian Electric Light Company, and Maui Electric Company to retain 10 percent of after-tax DR savings. (Note that HECO subsequently entered into an agreement that eliminated such incentives if they would cause the company to exceed its allowed ROE.)[11]
- Since 1995, the Indiana URC has been allowed to approve incentives "for earnings from prudent investments in both supply-side and demand-side resources."[12] The incentive mechanism may take one of three forms: a share of the net benefit attributable to a demand-side management program, a greater than normal ROE for DSM expenditures or adjustments to the utility's ROE based upon DSM program performance.
- A Kansas statute authorizes electric utilities to earn a premium on investments of up to 200 basis points over otherwise allowed ROE. This is for renewable generation, conservation, or energy efficiency.[13]
- The Massachusetts DTE issued guidelines in 2000, providing that distribution companies can earn a return on capitalized program costs equal to the average yield on three-month Treasury bills.[14]
- A Montana statute authorizes the PUC to approve ROE premiums of up to 200 basis points for capitalized DR program expenditures. (As of February, 2005, none had been granted.)[15]
- On April 28, 2004, the Nevada PUC adopted revised integrated resource planning rules to allow for a 5 percent ROE premium for energy efficiency investments that are deemed "critical."[16]
- Wisconsin allows utilities to earn the same ROR on capitalized DR expenditures as it would earn on generating assets in rate base. For example, Wisconsin Power & Light administers its energy

[10] Before the Hawaii Public Utilities Commission, Order No. 19019, Docket No. 00-0169, November 15, 2001, and Order No. 19020, Docket No. 00-0209, November 15, 2001.

[11] See: Before the Hawaii Public Utilities Commission, In the Matter of Hawaiian Electric Company, Inc. For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives, Docket No. 05-0069, Decision and Order No. 23258, Filed February 13, 2007, p. 56.

[12] Indiana Administrative Code, Title 170 , Article 4, Section 8-7. http://www.state.in.us/legislative/iac/T01700/A00040.PDF? (Accessed March 9, 2007).

[13] Regulatory Research Associates, Commission Profile – Kansas, March 2007.

[14] Regulatory Research Associates, Commission Profile – Massachusetts, December 2005.

[15] Regulatory Research Associates, Commission Profile – Montana, March 2006.

[16] Before the Public Utilities Commission of Nevada, In re: Application of Nevada Power Company for approval of the second amendment to the Supply-Side Action Plan of its 2003 Electric Resources Plan, Docket No. 04-6030, Order, September 17, 2004.

> efficiency programs through its Shared Savings program, which has been in place since 1987 and is granted a "shareholder rate of return."[17]

As explained in Chapter VII, most states use a mix of approaches that remove financial disincentives to pursue DR and energy efficiency, with many states going beyond this to provide the utility with meaningful positive incentives.

[17] Before the Public Service Commission of Wisconsin. Application of Wisconsin Power and Light Company for Authority to Increase Retail Electric, Natural Gas and Water Rates, Docket No. 6680-UR-111, Final Decision, September 13, 2002, pp. 44-46.

IV. PERFORMANCE MODEL FAMILY (FAMILY 2)

A second distinctive family of approaches is the Performance Based Ratemaking (PBR) mechanisms. In these models, a long-lived PBR plan is designed as a revenue/rate cap for a defined period during which the utility keeps some or all of the savings relative to that cap, including those arising from implementation of energy efficiency programs. While there are many permutations to defining the specific elements in this type of model, we identified just one basic model in this family that we refer to as Performance-Based Ratemaking (PBR) business model (Model 2a).

A. Performance-Based Ratemaking Business Model (Model 2a)

PBR plans have two generally recognized benefits. First, the period between tariff reviews is pre-specified (generally ranging from three to seven years) so that a rate case is not triggered by a change in the company's rate of return within that period. As a result, PBR leaves in place a set of regulated maximum rates longer than under traditional rate-of-return regulation—which increases the company's incentives to lower its costs and expand its sales. Breaking the link between prices and costs during the term of the plan gives the company an incentive to improve its performance. Second, longer periods between tariff reviews reduce the direct administrative expense of rate regulation.

These salutary effects of PBR plans are realized only if the regulated rates themselves continue to reflect reasonable costs during the PBR period. Some PBR plans include a rate freeze during some term of the plan. Often, however, price or revenue cap plans[18] include a formula that allows rates (or revenue) to rise with inflation. Such inflation adjustment is tempered—lowered—by expectations of industry productivity growth, which allows more utility services to be rendered at a lower cost. Thus, basic PBR plans allow rates to increase by slightly less than the full inflation rate, reflecting expected productivity improvements.[19] The size of the productivity offset, in conjunction with the inflation factor and other parameters, allows the maximum rates under the plan to move in a reasonably cost-based way during the time the PBR plan is in effect.

In terms of energy efficiency, a PBR plan can incorporate multi-year versions of the very same regulatory mechanisms used in traditional regulation, which allows the utility to recover the direct costs and be compensated for lost throughput. A revenue cap, for example, breaks the link between rates and earnings, although great care is needed in designing the revenue cap.

The following lists the different factors of a PBR model as they relate to energy efficiency:

- *Value proposition*: Utility is rewarded by retaining the cost savings that arise when buying, building, shifting loads between peak and off-peak periods, or conserving. Innovative regulatory mechanisms cause the utility to internalize costs and give the utility incentive to act efficiently.

[18] It is useful to distinguish between price caps, which tend to be fairly hands-off, and the inescapably more hands-on nature of growth-adjusted revenue caps. While it is very easy to freeze rates in a PBR plan, it can be quite challenging to design a growth adjustment factor that would allow a multi-year revenue cap plan to work.

[19] The productivity commitment in a price cap plan is the mechanism by which customers receive the benefit of the regulated firm's expected productivity growth over and above the average productivity growth of firms in the U.S. economy.

- *Revenue Model and Rate Treatment*: The utility keeps the difference between the allowed revenues and costs. In effect, the utility gets paid the avoided cost of the next resource. Rate/revenue indexing scheme with long plan life.
- *Customers and services*: The actual energy efficiency offerings may vary but they would have the character of being the least-cost method to solve a customer or group of customers' energy needs against a rate benchmark. The utility is rewarded for creative solutions and a wide range of services may result in the "right" opportunities being developed.
- *Required competencies*: Utility knowledge of costs, options, and customers and ability to manage them. Ability to create regulatory innovation and see it implemented.
- *Scale/scope/timing*: Mid-term. Scale and scope of the energy efficiency activities will be limited by what is cost effective for the utility.
- *Risk to sustainability*: This model creates an environment for more creative solutions to customers' energy efficiency needs and for sustained investment in energy-efficient equipment markets. This is a challenging model to get right and the challenges should not be underestimated. It requires both regulators and the utility to be comfortable with forecasting future revenue and costs in a base case for benchmarking. Otherwise substantial opportunities for "gaming" the system exist on both sides. Even if this model is pursued, the throughput issue must still be dealt with (either through the indexing formula itself or through marginal-cost based rate design). Other key risks include the potential for costs to grow more quickly than revenues, the inability to manage costs, and the political risk of the plan itself. There is the risk that proposals may be negotiated to a configuration (e.g., via a productivity "stretch factor") that is non-symmetric. There is also the risk that savings may be taken away by the regulator when plans are reset. Durability depends on the ability to manage costs over a long period of time.
- *Enabling policies*: Enabling policies include the design of the regulatory structure, monitoring, exit ramps, and sharing formulas.

This approach will appeal to jurisdictions where utilities and regulators want more flexible arrangements to transition to more economic investment in energy efficiency, to the extent they are comfortable that they can manage the risks outlined above.

A current example is the "Simplified Incentive Plan" adopted by Boston Edison Company (now NSTAR after the merger with Commonwealth Energy).[20] This is a price cap plan that allows rates to rise each year by the amount the gross domestic price index (GDPPI) rises, less a predetermined productivity offset. The offset ranges from .05% in 2007 to .75% in 2012. Since GDPPI has been growing about 2.5% a year, this means NSTAR's rates probably can grow 2% – 1.75% a year through 2012, when the current plan expires. NSTAR is a "wires-only" (distribution) company, and this plan applies only to its unbundled distribution rates. Nevertheless, this model is equally applicable to a traditionally integrated utility, although the specific parameters (e.g., the offset values) would change.

[20] *Petition of Boston Edison Company et al…for Approval of a Rate Settlement Effective January 1, 2006*. D.T.E Order 05-85 (December 30, 2005).

B. Key Elements of a PBR plan

Important elements of a PBR plan may include: 1) exogenous costs/mandated costs 2) positive incentives; and 3) decoupling/revenue caps.

- **Exogenous costs:** PBR plans should be designed so that pass-through mechanisms are included in the PBR formula for costs that are beyond the control of the utility (i.e., exogenous costs or Z-factors).[21] Commissions can include conservation and demand response costs as an exogenous cost so the utility fully recovers these costs even though a rate formula is in place for its rate base. Essentially, a tracker or capitalization approach designed specifically for energy efficiency costs could be included in the PBR plan.
- **Positive Incentives:** In the past, commissions have approved penalties for service quality metrics (i.e., customer service and outages) to provide incentives for the utility to address these issues. PBR mechanisms may also include positive incentives to reward a utility if it achieves certain specific objectives related to energy efficiency. Regulators such as the Maine Public Utility Commission use this approach.[22]
- **Decoupling Mechanisms/Revenue Caps:** Decoupling mechanisms based on strict revenue caps may be problematic in service areas with high customer growth due to the increased difficulty for the utility to raise capital to maintain and expand the distribution system. Establishing a growth adjustment factor (i.e., customer growth, sales growth or peak demand growth) in order to link revenues with customer growth rate allows the utility to make necessary investments to serve its customers adequately.

To summarize, in this business model, utility prices/revenues are fixed by a long-term adjustment formula that may reflect, in part, avoided cost. Shareholders benefit when the utility generates savings relative to the costs assumed in the revenue formula – and share the savings for the life of the PBR plan. Thus the utility is incented to choose the most reasonable option among buy, build, conserve, or shift. This model is assumed to lead to more investment in energy efficiency than under more traditional models because the utility does not have an inherent bias toward large capital expenditures. There are strong incentives for utilities to engage in cost management. The utility will be more willing to find the least cost solution which in many situations will be additional investment in energy efficiency. In a long PBR plan, the investment in energy efficiency may be more sustainable and market transforming. In addition, rate increases can be pre-specified via an annual adjustment formula over the plan period thus smoothing rate increases.

While there are positive features of this type of model, it can be very difficult to get the right plan. As one utility executive noted in an interview, “A long time is a very long time to live with a PBR plan.” Much care must go into the design of the PBR plan to address the risks that costs grow more rapidly than revenue or vice versa and that regulators may take the savings back when the price/revenue cap is reset. While creating an environment favorable to sustainable investment in energy efficiency, the difficulty for this model is in designing a plan with which everyone can be comfortable.

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[21] A Z-factor is an item excluded, either in whole or in part, from the operation of the PBR mechanism. Examples include changes in income taxes, environmental laws, and accounting rules. A Z-factor is a way to allocate risks. A cost subject to a Z-factor is a risk not borne by the utility.

[22] CMP incurs a penalty if its DSM-related energy savings are below a specific percentage of the targeted DSM savings for the year and gets rewarded when savings are greater than targeted levels.

C. Experience of PBR Plans in the U.S.A.

The tools described above are ways for commissions to allow a PBR plan to achieve the goal of energy conservation while also addressing the need to allow utilities to recover its investment and attract capital in the market. Table 1 shows a number of illustrative examples of PBRs in the U.S.A. and elsewhere. A more detailed description of a California PBR plan is provided next.

Table 1. Type of Regulation by Utility

Company	Location	Type	Time Period
Southern California Edison	CA	Price	1997-2003
Ontario Distribution Companies	Ontario, Canada	Price	2000-2002
San Diego Gas & Electric	CA	Price	2005-2007
National Grid	MA	Price	2000-2009
Central Maine Power	ME	Price	2002-2007
Northern States Power Co.	ND	Price	2001-2005
Bangor Hydro	ME	Price	2002-2007
New Zealand Distrib. Companies	NZ	Price	2004-2009
E&W Distribution Companies	UK	Price	2005-2010
New South Wales Distrib. Co	Australia	Price	2004-2009
Enel	Italy	Price	2004-2007
PacifiCorp	CA, USA	Revenue	1998-2001
Norway Distribution Companies	Norway	Revenue	2002-2006
Scottish Power	UK	Revenue	1994-2001
Scottish Hydro	UK	Revenue	1994-2001
National Grid Company	UK	Revenue	1997-2000
Northern Ireland Electric	UK	Revenue	1997-2001

1. Southern California Edison

During the years 1982-1996, California had decoupling programs in place for its major electric utilities. California utilities participated in general rate cases every three years in which a level of fixed cost recovery was determined. An ERAM was used to “true-up” the allowed revenues with actual revenues between cases. The mechanism ensured the recovery of three key components of required revenue: return on equity, which was adjusted annually to reflect changes in interest rates; operating costs, which were tied to price indices, and thus grew each year; and rate base, which was adjusted to reflect forecasted capital expenditures.

California reintroduced decoupling in 2002, following the passage of legislation in April 2001 (§739.10), which directed the CPUC to reinstate its policy of breaking the kWh sales/revenues linkage. Southern California Edison (“SCE”) adopted a mechanism similar to the Electric Revenue Adjustment Mechanism (“ERAM”) in 2002. The SCE performance-based regulatory (PBR) mechanism was originally covered only until December 2001, but the CPUC elected to extend the PBR mechanism until superseded by Edison's next

general rate case (2003).[23] Under the PBR plan originally in place, variations in sales translated directly into variations in revenue. For this reason, SCE requested to make a specific revenue requirement adjustment for customer growth in its PBR extension proceeding. The new balancing account tied to an adopted revenue requirement essentially restores the ERAM that was in place before the CPUC adopted PBR regulations. Like ERAM, the balancing account provides SCE with protection from revenue reductions that arise from conservation while ensuring that SCE obtains adequate, but not excessive, revenues.[24]

[23] *See*: California PUC Decision 01-06-038, "Opinion Extending Southern California Edison Company's Performance-Based Ratemaking Mechanism," June 14, 2001.

[24] California PUC Decision 02-04-055, "Decision Granting Petition to Modify Southern California Edison Company's Performance Based Ratemaking Mechanism," April 22, 2002.

V. ENERGY SERVICES MODEL FAMILY (FAMILY 3)

The third family of models focuses on energy efficiency services sold directly to retail customers on a fee-for-service basis. Customers who desire or see value in additional expenditures for energy efficiency service can be offered those services for a fee. This family aligns the utility's and customer's incentives and these models are less sensitive to the ebb and flow of regulatory interest in energy efficiency, which may create a more sustainable environment for growth in these services over time. In each of these models, regulatory programs to deal with the throughput issue would be used.

At the same time, there are several issues with these models that need to be addressed, including competitive concerns, customer demand in markets where rates are low and relatively stable, and the possibility that the demand for these services may not justify the cost of creating and maintaining programs to exploit these markets. The regulatory issues associated with this approach are discussed in **Chapter VI**.

In reviewing the family of business models, we identified three specific models that largely build on the "fee for service" type model but which vary in their emphasis. The three identified business models in this family are: Customer Infrastructure, Fee-for-Service, and Green Power.

A. Customer Infrastructure Business Model (Model 3a)

In the Customer Infrastructure business model (Model 3a), the utility contracts with a customer for delivery of specified customer energy services such as heating or cooling. The utility then manages the cost and risk of delivering the contracted service, and potentially assumes ownership or direct operation of customer energy infrastructure. This model could be manifest as an ESCO or through some kind of "premium service" model. It works when the utility wants to get as close as possible to the customer. It involves no regulatory incentives or performance based ratemaking. But as noted above, it may have to be implemented by the utility on a non-core, below-the-line basis or, if required by a regulator, as unregulated affiliates with appropriate separations. The key elements of this model are as follows:

- *Value proposition*: The utility provides a menu of energy management and other value-added energy services, potentially including ownership of the customer's energy infrastructure (heating/cooling, process steam, etc). The utility contracts for delivery of the services and manages cost/risk.
- *Revenue Model and Rate Treatment*: Revenue is based on contract terms through negotiation with customer. The utility is paid for assuming customer risk.
- *Customers and services*: The target market could include larger customers, particularly public customers, large multifamily buildings, and commercial and industrial campuses.
- *Required competencies*: Energy analysis, cost management, investment analysis, risk management, and contracting skills.
- *Scale/scope/timing*: May depend on regulatory approvals, but most likely mid-term. Scale and scope are limited to larger or dense customers. Affiliate issues (including codes of conduct and ringfencing requirements) may also increase costs of competing, and thereby limit scale and scope. These regulatory issues are discussed in **Chapter VI.D.**
- *Risk to sustainability*: Risks include customer acceptance, technology obsolescence, price risk, technology performance, and complaints from competitors. To the extent that services are handled below the line, there is a fundamental regulatory risk that, at the next rate case (for services above the

line), the regulator imputes earnings from services against the revenue requirement. Non-core, below-the-line rate treatment and accounting-based cost allocation will be needed if operated within the utility, and ringfencing/affiliate transactions issues may be raised if conducted through an affiliate. This model can be sustainable in the long run, particularly when combined with PBR business model. However, this type of model may tend to be crowded out by Family 1 energy efficiency programs.

- *Enabling policies*: Consistent regulatory treatment is the single most important enabling policy.

This model is favored in situations where the utility wants to get close to the customer and adopt a durable model not dependent on special purpose regulatory mechanisms. It may work well in dense urban areas, among other reasons because of the opportunity to link ESCO-type services with district heating or cooling or both. Model 3a would most likely be pursued by a utility as part of its non-core business or, where required by the regulator, by a non-utility affiliate.

Illustrative examples of this business model include the district heating and cooling systems and facilities operated by the Consolidated Edison Company of New York and such third-party suppliers as NRG Thermal and Trigen, among others. Service offerings include bundles of thermal services (heating and cooling) together, in some cases, with on-site facility management and risk management.

B. Fee for Service Business Model (Model 3b)

In the fee-for-service business model (Model 3b), the utility sells energy efficiency services that customers value on a straightforward fee-for-service basis. The model is very similar to the customer infrastructure model (3a), except that the utility does not assume ownership or direct operation of customer energy infrastructure and therefore has less opportunity to manage cost/risk. Again, the utility or an affiliate seeks to meet and increase demand for these services so as to grow that business, but it does so without special regulatory mechanisms or performance-based ratemaking (except that there would be regulatory mechanisms to deal with the throughput issue). As with the first model in this family, the margins on certain energy services may be slim, which tend to lead utilities away from the business. The key elements of this model are as follows:

- *Value proposition*: The utility sells energy efficiency services to customers or system operators for a fee.
- *Revenue Model and Rate Treatment*: The primary sources of revenue are customer fees, management fees, ISO payments; there is little, if any, opportunity for rate base treatment. Non-core, below-the-line rate treatment if within the utility, ringfencing/affiliate transactions if conducted through an affiliate.
- *Customers and services*: Although the primary services relate directly to energy efficiency, other elements might include distributed generation, integration services, and aggregation for ISO DR.
- *Required competencies*: Knowledge of customers, utility grid knowledge and infrastructure, involvement in the ISO, and ability to aggregate customers.
- *Scale/scope/timing*: This model can be deployed now; scale and scope depends on location and the economics of relevant technologies.
- *Risk to sustainability*: Risks include customer and load loss. To the extent that services are handled below the line, there is a fundamental regulatory risk that at the next rate case (for services above the line), the regulator imputes earnings from services against the revenue requirement. This business model can be quite sustainable in the long run, particularly when combined with the PBR business

model. The Fee for Service business model may tend to be crowded out by Family 1 energy efficiency programs.

- *Enabling policies*: Mixture of services within the utility/codes of conduct.
- *Circumstances under which utilities would likely adopt the model*: Customers value energy efficiency services and are willing to pay for them. Particularly appropriate for jurisdictions that are concerned about rate impacts.

Illustrative examples (neither exhaustive nor limited to pure examples of this business model):

- **Georgia Power** – Contract for Differences products that RTP customers can use to manage exposure to market price risk. (An example is Georgia Power Company's price protection products.[25] Customers taking service under the Company's real time pricing program can purchase any one of a number of risk management products to limit exposure to hourly prices. For example, a Standard Contract for Differences (CfD) pays out to the customer when the hourly prices rises above some defined strike price (e.g., $.06/kWh). A Range CfD pays out when the hourly price is between some specified range (e.g., $.055 – $.09/kWh). Customers who value bill stability can opt for the Company's Flat Bill product, which charges a premium above the otherwise applicable class rate to guarantee a fixed monthly bill amount.)
- **Dominion Virginia Power** – Warranty programs (electric/water/gas/sewer line insurance products, furnace repair insurance, cooling repair insurance).[26] For a fee ranging from $3.25 to $5.25 per month, the company will insure customers against the need to replace water lines, gas lines, or sewer lines; and to repair heating and cooling systems or water heaters.

C. Green Power Business Model (Model 3c)

This business model may have implications for energy efficiency. The Green Power business model (Model 3c) is a specific form of fee for service that ties more directly to the utility generation mix. In this model, a utility offers green power to consumers who are willing to pay the full incremental cost of green power or offsets. This type of offering is designed to offer a value creating product to the green market segments without creating rate impacts to non-participants. The key elements of this model are as follows:

- *Value proposition*: Customers are given the ability to purchase renewable energy (green power) and/or to offset emissions associated with their energy consumption for a premium price. Consumers must be willing to pay the full incremental cost.
- *Revenue Model and Rate Treatment*: Services are sold at a premium price to cover incremental cost of green power or offsets. Possible carbon credits depending on the scheme. Long-term contracts may be required. There is a separations issue if within the utility, ringfencing/affiliate transactions if unregulated.
- *Customers and services*: Customers interested in environmentally friendly power (e.g., 50 percent renewable, 100 percent renewable, all-wind or all-solar, etc.) may also be interested in energy efficiency products.
- *Required competencies*: Utility knowledge of sources of green power and ability to manage them (in conjunction with the grid and other power supplies).

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[25] See: http://www.georgiapower.com/pricing/gpc-pdf/ppp-2.pdf (Accessed March 9, 2007).
[26] See: http://retail.dom.com/products/index.jsp (Accessed March 9, 2007).

- *Scale/scope/timing*: This business model can be deployed in the near- to mid-term. Scale and scope can be very broad, especially in those regions (Northeast, West Coast) where there is significant demand for green energy. Developing sufficient green power supplies may take some time in certain regions.
- *Risk to sustainability*: There is political/regulatory risk of ratcheting RPS requirements and changing rules. To the extent that services are handled below the line, there is a fundamental regulatory risk that at the next rate case (for services above the line), the regulator might impute earnings from services against the revenue requirement. Due to growing environmental sensitivity, this model is fairly likely to be sustainable in the long run, especially when combined with other business models in the Energy Services family of business models.
- *Enabling policies*: Key enabling policies include the design of the regulatory structure, monitoring, exit ramps, sharing. Interface with RPS. They also include design of mechanism to handle debt/equity issues of purchasing supplies versus building facilities.
- *Circumstances under which utilities would likely adopt the model*: If utilities perceive customer demand for green power. This model will likely be structured differently in competitive vs. regulated jurisdictions.

D. Applicability of Different Business Models and the Relationships Between and Among Them

1. Screening by utility type

The business models were reviewed for their relevance to different types of utilities. All six business models are potentially applicable to all major utility types (vertically integrated, wires only, and non-regulated) except that Conventional Regulatory Incentives and Performance models are not applicable to non-regulated entities. This is summarized in on the following page:

Table 2. Screening Business Models for Applicability by Utility Type

Business Model Family		Business Model Name	Vertically Integrated	Wires-Only	Non-Regulated
1. Traditional Regulatory Incentives	1a	**Shared Savings**	Applicable	Regulator decides whether avoided cost of generation is explicitly considered in energy efficiency activities undertaken by the wires company; if not, then scope of energy efficiency activities limited to avoided wires cost.	Not Applicable
	1b	**Capitalization**	Applicable	Regulator decides whether avoided cost of generation is explicitly considered in energy efficiency activities undertaken by the wires company; if not, then scope of energy efficiency activities limited to avoided wires cost.	Not Applicable
2. PBR Models	2a	**Performance-Based Ratemaking**	Utility will consider all energy efficiency activities based on the avoided costs that can be monetized by shareholders over the life of the plan.	Unless the plan explicitly includes a rate component for avoided cost of generation, only wires avoided costs that can be monetized by shareholders over the life of the plan are likely to be undertaken.	Not Applicable
3. Energy Services	3a	**Customer Infrastructure**	A significant issue is whether the services can be offered competitively by the utility or must be offered by an affiliate.	The dominant issue is whether the services can be offered competitively by the utility or must be offered by an affiliate.	Applicable
	3b	**Fee for Service**	A significant issue is whether the services can be offered competitively by the utility or must be offered by an affiliate.	The dominant issue is whether the services can be offered competitively by the utility or must be offered by an affiliate.	Applicable
	3c	**Green Power**	Applicable	The dominant issue is whether the services can be offered competitively by the utility or must be offered by an affiliate.	Applicable

2. Screening by market structure

It is also possible to screen the six business models to determine their applicability to different electric power market structures. The presence of an organized wholesale market, for example, can complicate matters for a vertically integrated utility wishing to deploy a Family 1 business model. Although the primary issue is unbundling, unbundled utilities in regions where there is an RTO present also face challenges in pursuing any of the energy efficiency business models, mostly related to the need to understand the relevant ISO rules related to possible compensation for energy efficiency activities. This is summarized in **Table 3**, immediately below:

Table 3. Screening Business Models for Applicability by Market Structure

Business Model Family		Business Model Name	Vertically Integrated, No Organized Wholesale Market	Vertically Integrated, with Organized Wholesale Market	Unbundled, RTO Present (Incl. Day 1, Day 2 Markets, etc.)
1. Traditional Regulatory Incentives	1a	**Shared Savings**	Applicable	Requires understanding of wholesale market rules and possible compensation from the wholesale market for energy efficiency activities.	Requires understanding of ISO rules and possible compensation from the RTO for energy efficiency activities.
	1b	**Capitalization**	Applicable	Requires understanding of wholesale market rules and possible compensation from the wholesale market for energy efficiency activities.	Requires understanding of ISO rules and possible compensation from the RTO for energy efficiency activities.
2. PBR Models	2a	**Performance-Based Ratemaking**	Applicable	Applicable	Requires understanding of ISO rules and possible compensation from the RTO for energy efficiency activities.
3. Energy Services	3a	**Customer Infrastructure**	Applicable	Applicable	Requires understanding of ISO rules and possible compensation from the RTO for energy efficiency activities.
	3b	**Fee for Service**	Applicable	Applicable	Requires understanding of ISO rules and possible compensation from the RTO for energy efficiency activities.
	3c	**Green Power**	Applicable	Applicable	Applicable

3. Differences in utility starting point and evolution from one family to the next

Utilities vary dramatically in where they begin the process of building a business model in the arena of energy efficiency. This diversity can be briefly captured in the following two-by-two matrix:

Initiating **Moving from no real programs to starting something**	**Implementing** **Aggressively seeking to add energy efficiency programs/initiatives**
Evaluating **Trying to determine whether there is anything meaningful to do**	**Maintaining** **Seeking to continue current efforts with some tweaking**

A summary table of regulatory mechanisms and policies applicable to each of the business models appears in immediately below (**Table 4**). A more detailed discussion appears in **Chapter VI**.

Table 4. Summary of Regulatory Mechanisms and Policies Applicable to Each Business Model

Business Model Family		**Business Model Name**	**Applicable Regulatory Mechanisms and Policies (Illustrative Examples Only)**
1. Conventional Regulatory Incentives	**1a**	**Shared Savings**	• Verification policy / procedure in practice (what's the algorithm) • Quantification of net benefits policy in practice (what's in, what's not) • Throughput mechanisms (rate design, customer service charge example; lost margin, decoupling mechanisms) • Shared savings mechanism
	1b	**Capitalization**	• Capitalization policy in practice (which costs are in, which are out) • Recovery mechanism for non-capitalized costs (tracker mechanism) • Incentive policy in practice (premium ROR) • Throughput mechanisms (rate design, customer service charge example; lost margin, decoupling mechanisms)
2. PBR Models	**2a**	**Performance-Based Ratemaking**	• Indexed mechanisms (price cap, revenue cap, multi-year escalating revenue requirements) • Model legislation authorizing PBR

3. Energy Services	**3a**	**Customer Infrastructure**	• Authority for premium services (legislation, or regulatory policy) • Separations mechanism (accounting, or price cap) • Affiliate code of conduct rules that allow this
	3b	**Fee for Service**	• Authority for premium services (legislation, or regulatory policy) • Separations mechanism (accounting, or price cap) • Affiliate code of conduct rules that allow this
	3c	**Green Power**	• Authority for premium services (legislation, or regulatory policy) • Separations mechanism (accounting, or price cap) • Imputation adjustment • Carbon credits mechanism

VI. ENABLING REGULATORY FRAMEWORKS

A. Overview and Purpose

Regulatory approaches that treat utilities fairly while doing good for society are a proverbial win-win situation. For private ownership of utilities to be sustainable and serve customers well over the long term, electric utilities must have a reasonable opportunity to recover all of their prudently-incurred costs, including the investor-required cost of capital. Utility regulation, as traditionally practiced, rewards utilities for selling more electricity, measured in kilowatt-hours (kWh); this is familiarly known as the throughput issue. Policy initiatives aimed at reducing electricity usage—such as energy efficiency programs—can lead to an erosion of utility revenues with no matching reduction in cost for service. Over the last 25 years, regulators have adopted regulatory mechanisms aimed at reducing or eliminating the regulatory disincentive to sell fewer kWh.

The purpose of this Chapter is to:

- Explain the standard (and emerging) ratemaking tools available to regulators to remove utility disincentives to reduce throughput through energy efficiency programs.
- Identify standard and emerging regulatory approaches that link stockholder compensation to utility demand response efforts.
- Discuss innovative alternative approaches that regulators could consider.

This Chapter is *not*, however, intended to provide a comprehensive overview of regulatory responses to the throughput issue.[27] Rather, we will review the standard regulatory tools that are available, emphasizing the potential financial implications. This Chapter will illustrate the financial impacts of the various approaches, with a focus on the utility's profits and cash flows. We provide case studies explaining how state regulators and utilities have developed a basket of approaches to address the disincentive/positive incentive issues, as well as a brief survey that highlights some of the regulatory mechanisms that the states are using.

B. Ratemaking Tools to Remove Regulatory Disincentives

1. Rate Structure

Utility rate structures can present a barrier to economically efficient decisions with respect to energy efficiency. This barrier can be reduced or eliminated by ensuring that utility rate structures more closely reflect marginal costs.

[27] Recent reports by ACEEE and RAP provide a useful overview of regulatory practice. See: Kushler, York & Witte, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives," American Council for an Energy Efficient Economy, Report Number U061, October 2006 and Harrington, Murray & Baldwin, "Energy Efficiency Policy Toolkit," The Regulatory Assistance Project, August 2006. For a more complete discussion of the pros and cons of broad decoupling mechanisms, see chapter 5, pp. 17-24 of *Distributed Resources: Incentives*, by Eugene T. Meehan and Wayne P. Olson, NERA white paper prepared for the Edison Electric Institute, May 31, 2006.

a. Financial disincentives presented by an improperly-designed rate structure

There are two primary ways in which rate design could provide a financial disincentive to utility to pursue energy efficiency activities that reduce throughput.

In standard utility rate design, the bulk of utility revenues are a function of energy consumption. Often, rates are improperly designed from a cost perspective, and a large proportion of utility fixed costs that do not vary with energy or demand are recovered in usage charges (energy and demand charges). When usage charges recover more than the incremental energy and capacity costs, policy initiatives aimed at reducing electricity usage through energy efficiency programs can lead to an erosion of utility revenues with no matching reduction in its costs for service. The additional costs must be borne by someone else—in the short run by utility shareholders, and in the longer run by other consumers. This represents a financial disincentive to encouraging energy efficiency. In addition, energy efficiency programs that result in reduced consumption at the time of peak may have an impact on utility investment needs, but such cost savings may not be realized immediately. The delay between infrastructure cost savings and revenue loss when consumers reduce their demand provides a disincentive to encouraging energy efficiency.

Distributed Generation (DG) is often considered as a demand-side alternative within the energy-efficiency world. However, when the utility rates are improperly designed and usage charges recover more than marginal costs, uneconomic bypass may take place if a consumer decides to install cogeneration because the cost it produces may be higher than the utility cost of providing the service. In addition, because a DG customer requires essentially equivalent utility facilities because of the need for standby (back-up, maintenance or supplemental) service, but consumes substantially less energy or demand than an equivalent customer without DG, the rate design would not equate cost and revenue in a reasonable manner. A utility may well have a financial disincentive to encourage DG, because the revenue lost from DG is significantly greater than the cost saved, if any, as a result of the DG installation.

b. Proper rate design

Rate design plays a crucial role in obtaining *efficient* demand response and encouraging investment in energy-efficient equipment. Any demand-response or energy efficiency initiatives require rates to properly reflect the incremental marginal costs of service, so that consumers can make socially-efficient decisions about their consumption and choice of appliances. The principles to ensure that both utilities and consumers have a financial incentive to engage in demand response include:

- Rate structures must be aligned with the underlying marginal cost structure of providing electricity service, so that changes in retail revenues can track changes in retail costs.
- Rate levels must be high enough to allow the utility to earn a sufficient return on investment, but the usage charges should be as close as possible to marginal cost in order to minimize the distortion in consumption.
- Allocation of the overall revenue requirement to the various categories of customers must recognize the principles of cost causation going forward.

In practice, many utilities rates do not follow these principles. Generally, an efficient way to design rates that remove disincentives for utilities to provide demand response is to set the per-kWh charges equal to marginal cost and recover more costs in the least elastic fixed (non-usage) charges (e.g., customer and contract kW charges).

Energy efficiency presents a fairly wide range of revenue and cost issues for utilities, making it difficult to generalize. Care must be taken to consider utility-specific factors and costs when designing rate structures. **Table 5** describes six alternative rate design approaches, their potential benefits, and the tariff designs required to implement them efficiently.

Table 5. Marginal Cost-Based Structures and their Potential Impacts

Name	Description	Positive Impacts	Potential Negative Effects / Conditions for Efficiency
Seasonally-Differentiated Rates	Rates vary with "seasons" specified for ratemaking purposes, which group months of similar costs (e.g., Summer, Winter, Spring/Fall).	Reflect seasonal variations in costs.	Tariffs that change only seasonally do not provide price signals of the differences between high and low cost periods within the day. Thus, there is no incentive for consumers for "peak-shaving" or demand management.
Time-of-Use (TOU) Rates	Energy (and demand) charges vary by time of day (Peak/ Shoulder/ Off-peak). Rarely adopted for residential customers, except on an optional basis.	When TOU charges reflect underlying marginal cost in each period, TOU rates may be effective tools in reducing utility disincentives for enabling energy efficiency. Encourages load shifting away from high-cost (peak) hours to off-peak periods. It also encourages the customer to invest in more energy efficient appliances to reduce usage at peak.	For TOU rates to serve as an efficient instrument for energy efficiency, they must be based on marginal costs. Otherwise, the utility will not be indifferent to a unit of load reduction because the revenue loss will be higher than the avoided cost in that period.
Block Charges	Inverted block rates have a lower energy charge for the first block of monthly consumption and a higher charge for any kWh in excess of that threshold. Declining block rates go in the opposite direction, and are usually adopted for economic development reasons. Block rates may have different charges by time of day.	Inverted block rates are useful when the revenue requirement is substantially smaller than marginal-cost based revenues. The tail block charge can be set at the average hourly marginal cost in the period while the revenue gap is reconciled through a lower charge for the first block. If differentiated by TOU periods, incentives for peak load reductions increase.	Inverted block rates promote conservation but unexpected reductions in kWh sales increase the utility's financial risk if the tail block charge is set higher than marginal costs. The size of the block also needs to be carefully chosen so that is lower than the monthly consumption of most consumers in the class.
Critical Peak Pricing (CPP)	TOU rates with a separate "critical peak price" that only applies in specified number of "high-cost events" called by the utility (e.g., high temperatures or high spot prices). CPP can also be combined with a flat (non-TOU) tariff.	Avoids the use of high-cost resources at peak periods, which may reduce transmission congestion and the burden on the distribution system during peak periods.	Revenue class neutrality and other constraints may not allow the CPP charge to be high enough to provide the necessary response in order to reduce utility capacity costs.
Real-Time Pricing (RTP)	RTP prices change from hour to hour with day-ahead or real-time market prices, generally associated with ISO pricing levels or based on expectations of system lambda.	Similar to CPP rates, but provide more accurate signals at all times and thus may lead to more efficient demand-side management.	Customers may find these rates too volatile, unless a hedging tool is also offered or a two-part structure is established.
Standby Rates for Distributed Generation (including net metering)	Rates for customers with on-site generation to compensate for utility generation service when the customer's own generation is out of service, and for the cost of the utility	With the use of smart meters, rational pricing policy for standby rates becomes feasible. DG customers receive a reasonable payment for their electricity, based on the utility's avoided costs, and face the right price	If standby rates do not follow a marginal cost-based structure that adequately compensates the utility for the cost of standby, DG results in uneconomic bypass.

Name	Description	Positive Impacts	Potential Negative Effects / Conditions for Efficiency
	distribution system. Absent a smart meter, customers' meters run backwards for the electricity sold back to the system.	signals when the customer's units are out of service. Standby rates should provide efficient signals for purchases of energy from the utility.	

2. Removing a Utility's Financial Disincentive

In the real world of imperfect rate structures, electric utilities have disincentives to pursuing energy efficiency. Unless rate adjustments are made to remove the utility's disincentive to reduce throughput, under traditional rate-of-return/rate base regulation the utility will strive to sell more kWh of electricity.

The implications of lost throughput on a utility's financial performance are clear. Revenue loss mechanisms are critical for utilities' financial health because small demand reductions can translate into large financial losses (see the sidebar example presented in Chapter 0). While this could be offset by a reduction in marginal costs, it is likely that those costs will be essentially unchanged in the short run. Any reductions in the cost of generating the electricity would be passed directly through to customers (via a FAC) without a return and any reductions in transmission and distribution costs are likely to be minimal in the short run given that T&D costs are largely fixed in nature. Thus, the utility will have lost revenues, while its costs would remain essentially unchanged in the short run.

There are a number of methods that can be used to remove the utility's disincentive to reduce throughput, ranging from straight-forward approaches to more complicated decoupling mechanisms. Rate adjustments can be made for:

- *Direct costs*. A utility should be able to recover prudently incurred energy efficiency-related costs in its revenue requirement in a timely manner. Specific rate mechanisms, such as trackers and capitalization (i.e., deferral) mechanisms, can be used to recover these costs. This would reduce the lag between the time when new, prudent, but unexpected costs are incurred and when they are recovered from ratepayers (that is, the regulatory lag would be reduced). This would strengthen the assurance that these costs would be recovered in rates, reducing the risk to utility shareholders.
- *Lost revenues*. A utility may well have a financial disincentive to encourage energy efficiency. For example, if the revenues lost from energy efficiency are significantly greater than the costs saved, if any, as a result of an energy efficiency installation, the lost revenue would present a financial disincentive. Given the reality of utility rate designs, substantial lost revenues can result from energy efficiency. Unless lost revenues are recovered through the ratemaking process, the utility would have a disincentive to pursuing programs that reduce throughput.
- *Comprehensive decoupling mechanisms*. Proponents of decoupling mechanisms (also known as an Electric Rate Adjustment Mechanism or "ERAM") would argue that a comprehensive decoupling mechanism would be a way for regulators to eliminate the disincentives the utility normally has to promote energy conservation by linking utility revenue to a target other than sales of electricity.[28] However, if not properly done, decoupling is vulnerable to a number of criticisms. For a complete description of decoupling, see "Distributed Resources: Incentives," prepared by National Economic Research Associates for Edison Electric Institute, May 2006.

[28] Additional names for decoupling include ERAM-per-customer, statistical recoupling, revenue indexing, revenue cap, or revenue-per-customer cap.

If regulators and policy makers determine that encouraging energy efficiency is in the public interest, then it makes sense to provide timely, durable, and predictable rate treatment for these costs. Two ratemaking techniques that would be particularly useful are tracking mechanisms and deferral ratemaking treatment.

- *Tracking mechanisms*. Trackers provide on-going cost reconciliation for a certain category of costs. O&M trackers are for certain categories of costs that are deserving of treatment outside a base rate case. Investment trackers would be aimed at improving the incentive to build certain kinds of infrastructure. There would need to be a public interest rationale for this treatment. The typical criteria for pass-through treatment (large and volatile costs that are beyond the control of the utility) would be good reference points, but not definitive. The pass-through of energy efficiency-related costs could be justified, for example, based on a "public interest" rationale (reducing the disincentive to pursue energy efficiency).
- *Deferral ratemaking (capitalization) treatment.* Deferral mechanisms would allow the utility to capitalize designated costs as a regulatory asset. The costs would be accumulated in a deferral account, would be included in rate base with a return of and on the accumulated deferred amount, and then would be amortized in a manner consistent with the ratemaking treatment. This would provide an improved assurance that the utility is able fully to recover its energy efficiency-related costs.

3. Positive Financial Incentives to Reduce Throughput

Utilities should have meaningful incentives to pursue the full spectrum of possible solutions to achieving energy efficiency. There are three basic forms of positive financial incentives: sharing-of-benefits mechanisms, return on equity (ROE) adders, and performance-based rewards.

Incentives should be tailored so that the energy efficiency initiatives that result are efficient with benefits that outweigh costs. The recovery of energy efficiency investments and expenses should, for example, be timely and full. If energy efficiency expenditures are recovered through specific rate mechanisms that clearly provide for full and timely recovery, then the incentive to invest in energy efficiency would be strong.

To provide an effective inducement to energy efficiency involvement by utilities, the recovery of earned incentives should be incremental to base earnings. The particular incentive mechanism can be tailored to the purpose and jurisdiction.

While positive incentives can be beneficial, they are often structured as potential profit adders, without a guarantee of benefits to utility stockholders. Removing the disincentives to increase throughput guarantees the utility that it will be no worse off. These two ideas are not mutually exclusive.

Positive incentives should properly be in *addition* to—not a substitute for—regulatory mechanisms that remove the utility's incentives to increase throughput. This principle is not always followed. Minnesota, for example, had lost margin recovery, but switched to a positive shareholder incentive, stating:

> Although conservation investments dropped immediately after lost margin recovery was ceased, since that time conservation investments have recovered, remained stable and appear to be cost-effective…Informally, utilities have indicated that the reasons that utility management is willing to support conservation investments are:
>
> – Recovery of the conservation investment is guaranteed including a carrying charge on these investments and an annual automatic adjustment to rates to recover these investments.

- The financial incentive makes the investments more palatable.[29]

To increase the attractiveness of energy efficiency, positive incentives should be coupled with the removal of disincentives.

[29] For a summary of Minnesota's experience, see: Phyllis A. Reha, "Decoupling Energy Sales from Revenues and Other Approaches to Encourage Utility Investment in Efficiency: The Minnesota Approach," State EE/RE Technical Forum, http://www.epa.gov/cleanrgy/pdf/keystone/5_19MN_DSM_Incentives_Reha.pdf (Accessed January 31, 2007).

Table 6,, shows that many states do this.

a. Sharing Savings Mechanism

A "sharing mechanism" splits a portion of the achieved efficiency savings (e.g., 50/50 or 80/20) between shareholders and ratepayers. Ideally, the portion of benefits awarded to the utility would increase as the percentage of energy-savings goal achieved increases, since each additional "efficiency" gain would be more costly than the previous one. Sharing mechanisms, commonly seen in utility proceedings, are clear in principle; the difficulty has to do with identifying and measuring the achieved efficiency savings. Utilities would be rewarded with a specific percentage of the net benefits (as measured by the utility test) created by actual investments in conservation. Under this incentive design, utilities would be rewarded for delivering their programs more cost-effectively. This occurs because more net benefits are created when actual costs are lower than projected.

b. ROE Adders

ROE adders (rewards and/or penalties affecting the utilities financial performance) are another way to provide a clear benefit to utilities for the pursuit of efficiency in the organization of utilities and the consumption of energy. In two cases, for example, the Iowa Utilities Board provided a utility with an increment to the allowed return on common equity to reflect merger-related management efficiency.[30] ROE adders provide a clear incentive to the utility.

c. Performance Incentives

Performance incentives reward utilities when the utility achieves a specified goal or level of success implementing and developing an energy efficiency program. For example, in Connecticut, utilities can earn "performance management fees" depending on goals established by the Connecticut DPUC, such as the program's lifetime energy savings or demand savings.

4. Survey of Ratemaking Approaches

Regulatory jurisdictions have implemented approaches aimed at reducing the utility's disincentive to pursue energy efficiency. **Table 6** describes current examples of incentive programs that have been implemented by regulatory commissions.

[30] *See*: Iowa Utilities Board, Re: Midwest Gas, a Division of Iowa Public Service Company, Docket No. RPU-91-5, Order dated May 15, 1992, pp. 22-23; and, Iowa Utilities Board, Re: Interstate Power Company, Docket No. RPU-86-8, Order dated March 2, 1987, p. 6.

Table 6. Illustrative Examples of Ratemaking Programs, by State

State	Type of Program	Description
Arizona	Shareholder Performance Incentive	APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from approved energy-efficiency DSM programs. Such performance incentive will be capped at 10 percent of the total amount of DSM spending.
Hawaii	General Plan	General integrated resource planning guidelines permit the use of financial incentive mechanisms to encourage the implementation of DSM programs. Specifically, the guidelines permit recovery of lost revenue resulting from successful DSM programs. Utilities are permitted to retain 10 percent of the after-tax savings resulting from the DSM programs, capped if such recovery would cause HECO to exceed its current authorized return on rate base.
Hawaii	Lost Margin and Shareholder incentives	HELCO and MECO only may recover lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. On November 12, 2004, HECO filed a request for a $74.2 million base rate increase.
Indiana	General Plan	The URC has approved incentive plans for DSM programs that permit utilities to retain a portion of the savings associated with such plans. PSI Energy is authorized to defer, with carrying charges, prudent DSM-related program costs, lost revenues, and a shared savings incentive amount (up to 20 percent of savings), for recovery in subsequent base rate cases.
Indiana	Specific Examples	The URC also has approved a lost margin tracker for Southern Indiana Gas & Electric (SIGECO) that compensates the company for any revenue fall-off resulting from the operation of DSM programs. SIGECO may earn up to a 2 percent ROR bonus on its DSM investment, provided that certain performance efficiency targets are met, and a 1 percent ROR penalty may be imposed if performance falls below certain benchmark levels. SIGECO is a subsidiary of Vectren.
Kentucky	Lost Revenue Recovery	Kentucky allows lost revenue recovery for both electric and gas DSM programs. Recovery mechanisms are determined on a case-by-case basis.
Minnesota	Modified Plan	The PUC modified Northern States Power's and Minnesota Power's incentive DSM mechanism. Under the revised mechanism, the companies are no longer permitted to recover lost margins. Incentives are to begin when the utilities surpass 90 percent of their energy savings goals, and are to be capped at the lower of 30 percent of actual expenditures or 30 percent of approved expenditure levels.
Montana	Legislation	By law, the PSC can approve up to a 200-basis-point ROE premium for DSM program expenditures. To date, no companies have been granted such a premium.
New Hampshire	Shareholder Performance Incentive	The New Hampshire Energy Efficiency Working Group proposed a shareholder incentive mechanism. The proposed shareholder incentive is a sliding scale incentive with two components: 1) the cost-effectiveness component, which is based on the relationship between the projected New Hampshire Cost-Effectiveness test (NHCE) and the actual year-end NHCE and 2) the energy savings component, which is based on the relationship between the projected lifetime kWh savings from installed measures (planned savings) and the lifetime kWh savings from actual installations (installed savings).
Nevada	ROR Incentive	Nevada allows a bonus rate of return for DSM investments 5 percent higher than authorized rates of return for supply investments
South Carolina	Company-Specific	Both Duke Power (DP) and South Carolina Electric & Gas (SCE&G) have been authorized incentives for DSM programs.

C. Decoupling via a Revenue Cap Plan

As discussed in **Chapter IV**, price or revenue caps can, when properly constructed, give the utility incentives to improve operational efficiencies. Jurisdictions that are open to more complex ratemaking and longer term price indexing plans can achieve incentives that are both stronger and reward economic efficiency in energy efficiency implementation. Other jurisdictions can still provide incentives that should prove effective at encouraging energy efficiency deployment, but these incentives may be weaker and less well targeted to efficient energy efficiency deployment.

Price and revenue caps differ with regard to their potential impact on utility sales. A utility under a price cap plan will have an incentive to increase its sales, especially if its marginal revenue greatly exceeds its marginal cost (which is highly likely for a company with mostly fixed costs). That is, given a price cap, sales expansion may be the most expedient way for a company to increase its profits.

Revenue caps incorporate decoupling into a multi-year price-cap plan. The defined terms of these approaches give the utility an incentive to pursue efficiencies. After the term of the revenue cap plan has expired, these efficiencies would be captured in the next rate case, which would lower rates for ratepayers. In this sense, these plans are a form of sharing mechanism: the utility will capture the benefits for the term of the plan and ratepayers capture the benefits afterwards.

The recognition that an absolute revenue cap provides strong (and undesirable) incentives for sales reduction has led to proposals that aim to attain a degree of sales “recoupling” during the formula period—a partial reversal of the disincentive—while at the same time maintaining the positive aspects associated with the revenue cap approach. The way to achieve this recoupling is to introduce a growth adjustment factor. Various methods of recoupling have been proposed, using metrics such as customer growth, sales growth, or peak demand growth. The purpose of a growth adjustment factor in a multi-year revenue cap plan is to find a way to account automatically for the fact that the utility will continue to invest and grow throughout the course of its PBR plan.

D. Non-core ESCO-type Energy Efficiency Services Offerings

ESCO-type services can reasonably be offered by a utility on a non-core basis, allowing the utility to retain for the benefit of utility shareholders the rewards/risks associated with these non-core activities. With proper use of regulatory safeguards, the customers of the utility would not subsidize the utility’s non-core ventures and would be insulated from risks/returns associated with non-core ventures.

Utilities should not be foreclosed from competing in non-core markets because such market foreclosure could have the effect of discouraging lower prices (and/or better service) for consumers even though there is no anticompetitive harm. Regulatory burdens, when imposed asymmetrically, can interfere with the efficient operation of markets by artificially raising the going-forward costs of the firm to which they are applied. Asymmetric regulatory requirements could result in artificial handicaps for the incumbent (or new entrants) and call into question whether or not any market “successes” of new entrants (or incumbents) are due to superior performance on a going-forward basis, or are just based on the asymmetric imposition of regulatory burdens.

The core regulated functions of an electric utility (including closely related incidental activities) would be treated on an above-the-line basis while non-core utility activities would be treated below-the-line. This would insulate core utility customers from the risks/returns associated with non-utility ventures, while allowing utilities the opportunity to compete against non-utility companies in non-core markets. This

approach accommodates the competitive realities that utilities currently face by allowing utilities to use discretion to respond to competitive pressures by diversifying. The following principles could be followed to provide a workable boundary between core and non-core utility activities:

1. Regulated service customers should not subsidize utilities' non-core competitive activities nor should non-core competitive activities subsidize regulated customers. Non-core utility service would include any service provided by an electric utility that does not meet the definition of core utility service.
2. Regulated service customers should be insulated from the investment risk and returns associated with utilities' non-core activities.
3. Regulators should eschew broad prescriptive mandates and instead should identify the boundary between core and non-core utility activities.
4. Regulators should ensure that affiliated interest transfer payments are based on prevailing market prices, where possible. Where market prices are not available, transfer payments should be at least equal to incremental cost.
5. Regulators should establish a pro-competition framework, not a pro-competitor framework.

Cost allocation procedures can allow adequate and efficient regulation of the utility while also allowing the realization of operating efficiencies and reduced transaction costs that benefit consumers. And behavioral approaches (i.e., standards of conduct) can be developed to ensure that a utility's non-core activities do not have an inappropriate competitive advantage over non-regulated firms because of asymmetric access to customer information or other advantages stemming from the firm's regulated monopoly status. These issues can best be addressed on a case-by-case basis as issues arise.

This approach would avoid the administrative and transaction costs associated with forming a non-utility affiliate. Before requiring separation of core and non-core ventures in separate subsidiaries, a regulatory agency could examine the transaction costs that would result. These costs include:

- *Costs of Establishing and Maintaining a Separate Subsidiary*. Diversification within a utility can avoid the costs associated with forming a separate subsidiary. These include the various legal, accounting, and other expenses associated with the formation of a separate subsidiary as well as the ongoing costs of maintaining and operating a separate corporate entity.
- *Increased Overhead Costs and Reduced Operating Efficiencies*. Diversification within a utility can reduce overhead costs by facilitating efficient sharing of resources. For example, the same accountants can provide services to core and non-core utility ventures. These benefits may be foregone if separation is required. More generally, the cost of coordinating successive stages in a production process might be increased.

Because these costs will ultimately affect core customers, careful cost/benefit analysis should be undertaken before requiring a separation approach.

APPENDIX A: EXECUTIVE INTERVIEW GUIDE

Introduction

NERA is conducting a project for EEI to examine the role of energy efficiency in the future utility activities. This interview is confidential and you name will not be associated with specific answers in our report. If it is acceptable to you, I am going to audiotape the discussion. This is for note-taking purposes only.

Overview of Issues for Energy Efficiency and the Utilities

The purpose of this first set of questions is to gather an overview of issues related to energy efficiency and utilities. In our study, we are considering use of the term DER, short for Distributed Energy Resource, to encompass a wide range of activities including distributed generation, demand response, energy efficiency, and related emission reduction efforts.

1) Are you familiar with this terminology? Is it useful to include all these elements in DER? Is anything important missing from our definition?
2) How important do you believe DER is for the U.S. electric utility industry overall today? Why do you say that?
3) What role do you believe DER will play in the industry in another 5 years? How about in 15 years?
4) What is your view of the regulated distribution company (DISCO) of the future? Will the future industry structure or business model differ significantly from what now prevails? In what ways?
5) How important do you believe DER is for your utility in particular? Why do you say that?
6) Are DR, Demand Response, and Distributed Generation activities equally important to your utility or are some of these more important than the others? Why do you say that?
7) Can utilities make money from DER activities on a sustainable basis? Why do you say that? Only in their service territory, or elsewhere too?

Overview of Energy Efficiency Business Models for the Industry

1) Is the concept of a “business model” clear to you? Why do you say that?
2) What are the key elements of a “business model” in your mind?
3) In your view, what are some examples of different business models for pursuing energy efficiency?
4) What business models do you believe financial analysts and investors will push for (expect, or reward financially) going forward?

As a starting point for this project we have identified 5 families of business models for the utilities pursuing energy efficiency. These models differ in the extent to which they require regulatory reform, offering services beyond commodity, and the extent to which customers, utilities, or regulators make the decision on what type of energy efficiency investments are made. I would like to briefly discuss each family of models and ask for your reaction.

Describe a model and then follow-up with the following questions. Repeat for all 5 families.

1) Are their currently utilities and states where this model exists? Can you provide an example?
2) With regard to energy efficiency, what are the benefits of this model for enhancing energy efficiency?
3) What are the weaknesses of this model for enhancing energy efficiency?
4) Is this a viable long-term strategy? Why do you say that?
5) What is required to make it a viable long term strategy?

AFTER ALL MODEL FAMILIES HAVE BEEN DISCUSSED:

1) Which of the types of business models do you feel matches your utility's current position with regard to energy efficiency? Why do you say that?
2) Which of the types of business models do you feel match where your utility will be in 5 years? Why do you say that?
3) Do you have any other comments or feedback on the five families of energy efficiency business models? Should any be eliminated or are any missing?

Business Models and Regulatory Frameworks

1) What regulatory interactions and initiatives has your company been involved in regarding energy efficiency? Are there specific regulatory mechanisms that you are pursuing? If so, please briefly describe these mechanisms. If not, why not?
2) In your view should energy efficiency activities be offered by the regulated utilities or should they be offered through non-regulated utility affiliates or other providers? Why do you say that?
3) What energy efficiency business models do you believe regulators will push for going forward in your state? Why? What about nationally?
4) What short-term changes in the regulatory model, at both the state and federal level, would be useful for you to maintain or increase your company's energy efficiency activities, if any?
5) What longer-term regulatory trends, at both the state and federal levels, would you envision to make energy efficiency activities a sustainable and attractive business model for your company?
6) What is your view of the "lost revenue" problem in energy efficiency initiatives? Why do you say that?
7) Are you familiar with the concept of "decoupling" and, if so, do you believe it offers an adequate solution to the problem in the long run? What other solutions are there?
8) Do you expect some form of carbon emissions limits at either the state or federal level? How soon would this occur?
9) If the new Congress taking office in early 2007 were to consider a new legislative package for the electric utility sector, what provisions should they consider adopting to "jump-start" energy efficiency business models? What provisions would be the most detrimental to energy efficiency?
10) Do you have any final thoughts on the relationship between energy efficiency activities and utilities that we have not discussed?

Thank you—that completes the interview.