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BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-220066, UG-220067, UG-210918 (consolidated)**
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility**	

EXHIBIT TO TESTIMONY OF

JASON L. BALL

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Utility Performance Incentive Mechanisms: A Handbook for Regulators

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Utility Performance Incentive Mechanisms

A Handbook for Regulators

Prepared for the Western Interstate Energy Board

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EXECUTIVE SUMMARY

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms. Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources.

Whether performance incentive mechanisms are added onto traditional ratemaking practices, included as part of performance-based regulation (PBR) plans, or considered as a central element of new regulatory and utility business models, they can be used to help improve utility performance. As with all regulatory mechanisms, they should be designed thoughtfully and they should build off of lessons learned from past practices.

Advantages of Performance Incentives

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

Potential Pitfalls of Performance Incentive Mechanisms

As with all regulatory mechanisms, the success of performance incentive mechanisms is very much dependent upon their design and implementation. Experience to date has shown that there are many potential pitfalls that regulators should be aware of:

> Disproportionate rewards (or penalties). Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.
>
> Unintended consequences. Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.
>
> Regulatory burden. Performance incentive mechanisms can be costly, time-consuming, or a distraction from more important activities for all parties involved. If this burden becomes too great, it can undermine the value of performance incentive mechanisms.
>
> Uncertainty. Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to performance incentive mechanisms create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.
>
> Gaming and manipulation. Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results.

In most cases, these pitfalls can be managed through sound design and implementation of performance metrics and incentives. They can also be mitigated by ongoing evaluation of and improvements to the incentive mechanisms. Chapter 6 presents a more detailed discussion of these pitfalls and recommendations for how to avoid them.

Performance Incentives Can Be Used in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance; to address areas

where regulators see opportunities for greater efficiencies or reduced costs; and to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result of pressures to reduce costs, and to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases, and cost trackers.

In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes.

In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

Key Principles and Recommendations

Based on our review of the literature and the lessons learned from various jurisdictions, we provide numerous recommendations and principles for designing effective performance metrics and incentive mechanisms. These are summarized in the table below.

Table 1. Key Principles and Recommendations

Regulatory Contexts **(Chapter 2)**	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics **(Chapter 3)**	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets **(Chapter 4)**	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties **(Chapter 5)**	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Questions for Regulators

Regulators may wish to ask several questions to help inform their decisions on whether and how to proceed with performance metrics and incentives:

- How well does the existing regulatory framework support utility performance?
- How well does the existing regulatory framework support state energy goals?
- What are the policy options available to improve utility performance?
- Are industry, technology, customer, or market conditions expected to change?
- Does the commission wish to articulate specific, desired performance outcomes? If so, in what performance areas?
- Does the commission prefer to oversee utility expenses and investments after the fact (e.g., through rate cases and prudence reviews), or to guide performance outcomes before investments are made?

Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally to allow for each step to inform the subsequent step, or they can be implemented all at once.

1. Articulate goals**.** The first step is to identify and articulate regulatory policy goals. These goals should help inform choices of performance areas, targets, and penalties.

2. Assess current incentives**.** Next it is critical to understand the financial incentives created by the current or anticipated regulatory context.

3. Identify performance areas that warrant performance metrics**.** Performance metrics may be warranted for traditional performance areas or new and emerging areas.

4. Establish performance metric reporting requirements**.** Review performance reports to monitor those areas identified above, to identify any performance areas that may require targets.

5. Establish performance targets, as needed**.** Establish targets to provide utilities with clear messages regarding the level of performance expected by regulators. Review results to determine whether any performance areas warrant rewards or penalties.

6. Establish penalties and rewards, as needed. Establish rewards or penalties to provide direct financial incentives for maintaining or improving performance.

7. Evaluate, improve, repeat. The effectiveness of the mechanisms should be monitored and evaluated on a regular basis to determine whether there is a need for improvement.

1. INTRODUCTION

Purpose and Overview

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms (sometimes abbreviated here as PIMs). Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources. The ultimate objective of performance metrics and incentives is to better align utility regulatory and financial incentives with the public interest.

In the following chapters, we identify many of the metrics and performance incentives that regulators have used to monitor and evaluate utility performance, as well as emerging metrics and incentives that are being discussed in jurisdictions facing new issues and challenges, such as integration of renewable and distributed energy resources.[1] We provide a set of principles and recommendations for regulators, based on our review of the large amount of literature on these topics and the lessons learned from the case studies that we reviewed. Our research is primarily focused on electric utilities, but we have included some metrics specific to natural gas utilities as well.

This handbook builds off of a Western Interstate Energy Board report titled *New Regulatory Models* (Aggarwal and Burgess 2014).[2] That report provides a number of examples of how performance standards have been used by regulators.

Industry Changes and Pressures

Traditional cost-of-service regulation was originally designed in an era of significantly increasing sales and decreasing marginal costs, where the primary decisions required by utilities were related to how much and what type of generation and transmission to build to meet growing customer demand, and where the main goal was to ensure just and reasonable rates. The conditions currently facing the utility industry have changed considerably, for instance:

- Retail sales are increasing at much lower levels than in the past, and some utilities are experiencing declining sales. Sales may drop even further as customers adopt more demand-side measures, especially energy efficiency, distributed generation, and storage technologies.

[1] In fact, even where utility commissions have not implemented specific utility standards, utilities already comply with a variety of industry standards set by organizations such as the Institute of Electrical and Electronics Engineers (IEEE), the Occupational Safety and Health Administration (OSHA), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), the Financial Accounting Standards Board, and the Environmental Protection Agency (EPA).

[2] The Phase I report is available here: http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

On the other hand, electric vehicles and other forms of electrification could lead to increased sales.

- Many utilities are facing the need to replace aging infrastructure, which may require significant capital investments that will not necessarily lead to reduced costs or increased sales.
- Utilities have many more options to choose from, in terms of generation, transmission, and distribution technologies, as well as more ways to address customer needs through resources on the customer side of the meter (including energy efficiency, demand response, distributed generation, automated metering technologies, and customer-facing smart grid options).
- Regulators have established a variety of public policy goals beyond simply maintaining just and reasonable rates. These include goals related to consumer protection, promoting competitive markets, encouraging and implementing demand-side resources, encouraging and implementing renewable resources, improving responses to major outages, and meeting carbon and other environmental constraints.

Some states are finding that traditional cost-of-service regulation may not provide utilities with the financial incentives to respond effectively to all of these developments. In some cases, traditional regulatory practices may provide financial incentives that hinder utilities from addressing these challenges. Consequently, performance metrics and incentives may provide an opportunity to better align utility incentives with evolving regulatory goals and the public interest in general.

Performance Metrics and Incentive Mechanisms

In this report we focus on both performance incentive mechanisms that use financial rewards and penalties to encourage utilities to meet specific targets, as well as performance metrics for simply monitoring and reporting utility performance. The relationship between the steps to implement these regulatory tools is shown in Figure 1 below.

Figure 1. Performance Incentive Mechanisms vs. Performance Metrics

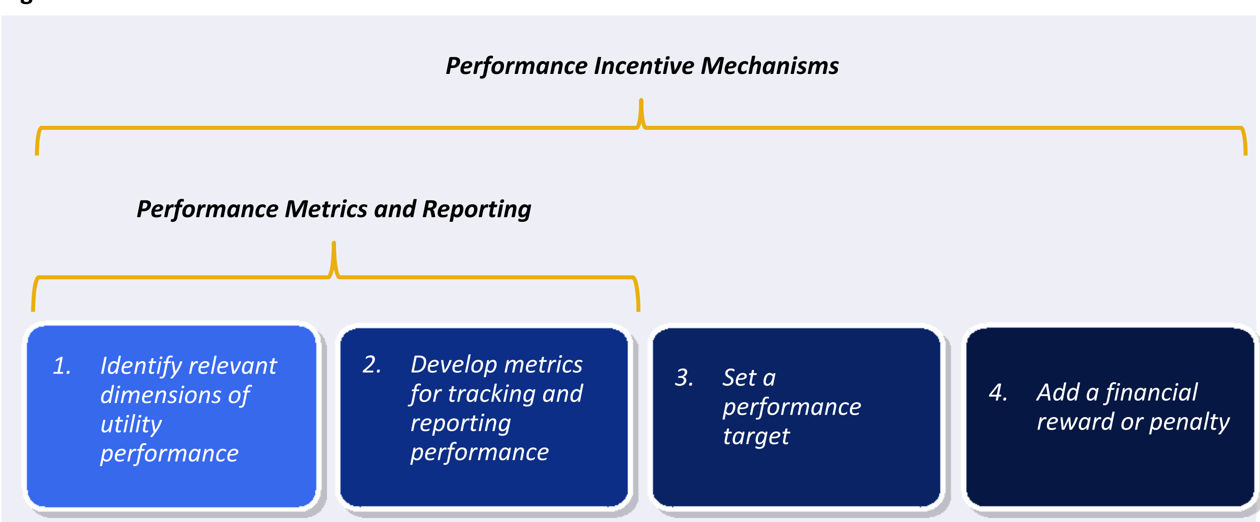

Figure 1 also highlights the various components involved in creating performance metrics and incentives.

These steps can be taken incrementally over time until the desired level of incentives is reached. First, performance metrics and reporting can be established to monitor utility performance. Second, specific performance targets can be set to provide a clear signal regarding the level of performance that is expected of a utility. Finally, financial rewards and penalties can be applied to increase the utility's motivation to achieve the performance targets. This incremental approach allows regulators and utilities to learn from each step before designing and implementing the next step. It also enables regulators to review utility performance without implementing financial rewards or penalties where such incentives are not necessary.

Alternatively, these four steps can be applied all at once, in the form of performance incentive mechanisms. This would be appropriate in those cases where regulators (a) have performance areas, metrics, and goals in mind, and (b) recognize the need for rewards and penalties.

Advantages of Performance Metrics and Incentive Mechanisms

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons. For example:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

2. REGULATORY CONTEXT

Evolving Regulatory Contexts

As Peter Bradford noted in the book *Regulatory Incentives for Demand-Side Management*: "All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others" (Bradford 1992). In other words, every regulatory environment contains a variety of financial incentives that will affect utility performance. In designing performance metrics and incentive mechanisms, it is critical to first understand the incentives that existing under the existing regulatory environment.

There is currently a wide variety of regulatory systems across the United States, as each state has adopted different regulatory mechanisms over time to address its own needs. However, it is useful to discuss three categories of regulatory contexts for the purpose of describing how performance incentives might fit into each. These categories include: cost-of-service (COS) regulation, performance-based regulation (PBR), and new regulatory models. These regulatory contexts are summarized in Table 2 and discussed below.

It is important to emphasize that these three categories are simplistic, by design, relative to the many variations of regulatory elements in use today. Few states fall clearly into one category or another. The purpose of this table is simply to identify the key distinguishing features among these three frequently-discussed categories.

Table 2. Three Categories of Regulatory Systems

Regulatory Element	Cost of Service Regulation	Performance-Based Regulation	New Regulatory Models Proposed to Date
Basis for initial rates	Based on cost-of-service studies using a test year	Based on cost-of-service studies using a test year	Would likely be based on cost-of-service studies; may be influenced by utility business plans
Frequency of rate cases	Utilities apply for rate cases as needed or required, typically to recover large capital investments or revenue attrition	Pre-determined, fixed period of time (e.g., five years) to encourage efficient management and operations	Pre-determined, fixed period of time (e.g., eight years) to encourage efficient management and operations
Base rate adjustments between rate cases	Generally none	Price cap modified to account for factors such as inflation and productivity	Price cap may be modified to allow for inflation, productivity, or costs included in utility business plans
Cost trackers	Generally limited to costs beyond utility control	May include trackers for capital costs not easily accounted for in the price cap	Would likely include trackers for capital costs identified in utility business plans
Prudency reviews	Generally applied after the fact, where excessive costs become obvious	Applied after the fact, in cases where excessive costs become obvious	Applied after the fact; would likely be limited, based on utility business plans
Resource Planning	Option to include integrated resource planning	Option to include integrated resource planning	Strategic business plans would be used to inform cost trackers and adjustments between rate cases
Revenue regulation	Option to implement a decoupling mechanism	Option to include a revenue cap, instead of a price cap	Would likely include a revenue cap, instead of a price cap
Performance Incentive Mechanisms	Focus on areas of poor performance or opportunities for improvement	Focus on areas that may experience service degradation in response to pressure to reduce costs	Designed to create incentives to achieve a broad set of desired outcomes

Traditional Cost-Of-Service Regulation

Traditional cost-of-service regulation is characterized by the following elements:

1. Base rates are set in a rate case, typically based on known and measurable costs identified in a test year (historical, future, or a hybrid).

2. Frequency of rate cases, which typically occur at the request of the utility for the purpose of recovering major capital expenditures or addressing revenue attrition. Commissions generally have the authority to request that a utility file a rate case, but this rarely occurs in practice.

3. Base rates generally remain constant until the next rate case.

4. Cost trackers and rate riders may be applied to some costs that are partly or wholly beyond a utility's control.

5. A utility's allowed return on equity is set by the commission in a rate case, and this return is earned on all investments that are placed into the utility's rate base. Actual profits may deviate from the allowed return on equity, depending upon many factors both within and outside a utility's control.

6. Prudency reviews are used retrospectively (after the investment has occurred) to ensure costs are reasonable. Cost disallowances as a result of prudency reviews are rarely applied, and then only in cases of egregious mismanagement or cost overruns.

There are several significant, widely-recognized financial incentives underlying traditional cost-of-service regulation. The most significant incentives include the following:

Capital expenditures. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect. In theory, prudency reviews can mitigate some of the incentive to maximize capital expenditures. However, in practice prudency reviews and disallowances are rare, burdensome, and are mostly applied to large capital expenditures.

Sales. Traditional cost-of-service regulation creates an incentive for a utility to maximize sales in order to increase profits. Whenever a utility's short-term marginal costs are lower than its average costs (i.e., the costs embedded in rates), then it can increase profits by increasing sales. This "throughput incentive" poses a significant financial disincentive to utilities with regard to energy efficiency and distributed generation. This incentive to increase sales, combined with the utility focus on capital expenditures, significantly undermines utility motivation to apply least-cost planning principles and to develop the most cost-effective balance of supply-side and demand-side resources. As a consequence, customers must cover significantly higher energy costs than necessary.

Regulatory lag. Regulatory lag refers to the period between rate cases when the utility is incurring costs, but rates have not yet been adjusted to recover these outlays. Some industry observers claim that regulatory lag provides utilities with incentives for efficient management and cost control, because utilities are able to benefit from any cost savings that they create between rate cases. On the other hand, regulatory lag can pose financial challenges for a utility, causing it to apply for rate cases more frequently. In general, the incentive created by regulatory lag depends upon whether the utility's average costs are decreasing or increasing relative to revenues (Costello 2014).

Risk. Under traditional cost-of-service regulation, utilities are generally permitted to recover all capital costs, with a profit. This certainty of cost recovery provides little incentive to reduce risks associated with major capital expenditures—expenditures that can involve considerable uncertainty and risk (Binz et al. 2012). Cost trackers and rate riders further eliminate risks to the utilities by shifting all of the risks associated with such costs to customers. For example, fuel adjustment charges can reduce incentives for the utility to optimize its generation portfolio to account for the risk of fuel cost increases.

Innovation. There is little incentive for utilities to adopt innovative practices, technologies, or resources under traditional cost-of-service regulation. Utilities have considerable certainty that regulators will allow them to recover costs of prudently incurred investments in conventional projects, but much less certainty about being allowed to recover costs associated with innovative practices and technologies with uncertain results.

Many states continue to rely upon some form of cost-of-service regulation, even in states that have restructured their electricity markets. Regulators in these states frequently employ a variety of tools to improve the alignment of regulatory incentives with the public interest, such as revenue decoupling, forward-looking costs on some items, and performance incentive mechanisms.

Performance incentive mechanisms under traditional cost-of-service regulation typically have been developed to improve service or reduce costs, for example, reliability, power plant performance, cost of renewable generation, or O&M costs. Some states have developed performance incentive mechanisms to support specific resource goals, such as increasing renewable energy generation, energy efficiency savings, and resource diversity.

Performance-Based Regulation

Performance-based regulation (PBR) was introduced in the US electric sector in the 1980s and became popular in the 1990s as an alternative to cost-of-service regulation, particularly in states that introduced retail competition (Sappington et al. 2001). One of the goals of PBR was to improve upon the financial incentives provided under traditional cost-of-service regulation, and to provide incentives more focused on operational efficiency and cost reduction.

Performance-based regulation is characterized by the following elements:

1. The time period between rate cases is fixed at the outset of each period, and is designed to be long enough to provide the utility with incentives to reduce operating costs and keep the operational savings between rate cases.

2. A price cap (or a revenue cap) is used to set prices for a fixed period of time.

3. Automatic adjustments to the price (or revenue) cap may be established to account for expected cost changes between rate cases. These frequently include automatic increases to account for inflation, coupled with automatic reductions to encourage productivity improvements. Many states adopted the “RPI – X” formula, where RPI is the retail price index and “X” is a productivity factor.

4. Trackers may be established to allow the utility to recover certain types of costs outside of the price (or revenue) cap, typically costs that are volatile and beyond a utility's control. Some states also allow trackers for major capital expenditures, because these costs are large and lumpy, and may therefore be difficult to accommodate in a fixed price (or revenue) cap.

5. Performance incentives are applied for key aspects of customer service, in order to ensure that utilities do not allow service to degrade in their pursuit of reduced costs and greater efficiencies.

6. Earnings sharing mechanisms are established to ensure that the utility's earned profits are neither excessive nor insufficient.

There are many different variations of PBR used in the United States today, incorporating different forms of the elements listed above.[3] The WIEB report *New Regulatory Models* referenced above provides several examples (Aggarwal and Burgess 2014). Also, there are many terms used to describe different combinations of these elements. The term "alternative ratemaking" is sometimes used synonymously with PBR. Some states use the term "multi-year rate plan" to refer to rates that are set for a fixed period of time, with automatic adjustments and cost trackers between rate cases. Such multi-year rate plans may or may not include performance incentives.

In theory, PBR is intended to provide more direct financial incentives for utilities to reduce costs, without heavy-handed, ongoing oversight from regulators. The key to this incentive is the fixed period between rate cases. If the utility succeeds in keeping its costs below its allowed revenues, it can keep the excess revenues. Capital investments made during the period should lead to reduced operations and maintenance costs, which would accrue to the utility until the next rate case.

In practice, there are many incentives embedded in PBR mechanisms, with various implications:

- The fixed period between rate cases should provide utilities with an incentive to reduce operating costs. However, the impact of this incentive depends upon the length of time between rate cases, where relatively shorter periods will result in more muted incentives.
- The productivity factor should provide an incentive to increase productivity. However, establishing the right productivity factor can be difficult, particularly when (a) there are few comparable peer utilities for comparison purposes; (b) utilities need to replace aging infrastructure; (c) utilities (or the industry) are in a period of rapid transition, in terms of markets, technologies, or operations; and (d) historical costs and practices are not a good indication of what future costs and practices will be.
- Placing certain types of costs into trackers eliminates the utility's incentive to optimize those costs and transfers the risks associated with those costs to ratepayers.
- If major capital expenditures are recovered through a fully reconciling cost tracker, utilities have little incentive to ensure that those costs are planned and managed as efficiently as possible. In such a case, it may be important to design a major capital cost tracker so as to provide such

[3] For a relatively recent survey, see Lowry, Makos, and Waschbusch 2013.

incentives, for example by establishing a mechanism that requires the utility to absorb a significant portion of any cost overruns.

- If major capital expenditures are not recovered through a cost tracker, it can become much more challenging to establish a price (or revenue) cap and a productivity index that provides cost control incentives while allowing the utility to adequately recover capital costs and protect consumers.[4]
- Performance incentives can be useful to prevent service degradation in light of pressures to reduce costs, or to improve performance in some areas. However, performance incentives must be designed carefully to achieve the desired results. The effective design of performance incentives is discussed throughout later chapters of this report.

In recent years, several PBR investigations have attempted to address some of the challenges associated with the incentives and implications listed above.[5] In addition, many of these issues have been investigated and addressed by Ofgem, the electricity and gas regulator in the United Kingdom, the first regulator to apply PBR to electricity utilities, and the creator of the model upon which many US PBR designs were based. After several decades of experience with PBR, Ofgem has significantly modified its PBR mechanism. The new mechanism being developed in the UK is referred to as RIIO (Revenues = Inputs + Incentives + Outcomes), and is discussed in some detail in Appendix A.

New Regulatory Models

In many states, electricity load growth has slowed significantly due to many factors, including increased use of distributed energy resources (DER) such as energy efficiency and distributed generation. At the same time, the electric industry is experiencing many forces that frequently increase costs, including: the need to replace aging infrastructure, increased transmission needs, requirements to reduce environmental impacts, and pressure to modernize the electric grid. Combined, these factors are simultaneously increasing the need for utility capital expenditures while reducing the revenue from sales growth they have historically relied upon. Traditional cost-of-service regulation and traditional PBR mechanisms may be ill-equipped to handle these challenges, and may not provide utilities with the incentives or the regulatory guidance needed to address them.

Some jurisdictions and stakeholders have begun to investigate new regulatory and utility business models to address the limitations of the current systems.[6] Several proposals in these contexts focus on

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[4] See, for example, Direct Testimony of Tim Woolf before the Maine Public Utilities Commission in Docket No. 2013-168, *Central Maine Power Request for Approval of an Alternative Rate Plan (ARP 2014)*, December 12, 2013.

[5] See, for example, Maine Public Utilities Commission Docket No. 2013-168 and Hawaii Public Utilities Commission Docket No. 2013-0141.

[6] See, for example, the New York Public Service Commission Case Number 14-M-0101, *Reforming the Energy Vision*; Hawaii Public Utilities Commission, Decision and Order No. 32052, Exhibit A: *Commission's Inclinations on the Future of Hawaii's Electric Utilities,* and Hawaii Public Utilities Commission Docket 2013-0141; e21 Initiative 2014; GTM Research 2015; and Lehr 2013.

PBR mechanisms, with the overall goal of creating financial incentives that are based more on performance and less on recovery of costs.[7]

These proposals include several modifications to the way that PBR is currently applied in the United States. For example:

1. Expand the types of performance metrics applied to utilities to include emerging performance areas such as system efficiency, customer engagement, network support services, or environmental goals (see Section 3.2). This is intended to provide regulatory guidance and financial incentives regarding the variety of outcomes that are important for delivering quality service and meeting state energy policy goals.

2. Shift the financial incentive away from investments in rate base and towards achieving performance goals. This can be accomplished by reducing the portion of revenue requirements that a utility recovers from rate base, and comparably increasing the portion of revenue requirements that can be recovered from performance metrics.[8]

3. Establish longer periods between rate cases. This is intended to increase the magnitude of the financial incentive to increase productivity and reduce costs between rate cases.

4. Provide more up-front guidance from regulators and stakeholders with regard to future major capital expenditures. This is intended to provide utilities with greater flexibility and incentive to adopt innovative and emerging technologies and practices.

Many of these modifications are consistent with those that have been adopted recently in the UK RIIO model, suggesting that the lessons learned from the UK PBR experience may be relevant to the new regulatory and utility business models being considered in the United States. This is discussed in more detail in Appendix A.

Some states have already established performance metrics or incentive mechanisms to address emerging performance areas, such as customer retail choice, grid modernization, and distributed generation interconnections. Examples and further discussion of metrics and incentives to address these emerging areas are provided in Chapter 3.

Performance Metrics and Incentives Can Be Applied in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the

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[7] See, for example, Energy Industry Working Group 2014; Malkin and Centolella 2014; Blue Planet Foundation 2014; e21 Initiative 2014; Massachusetts Grid Modernization Steering Committee 2013.

[8] For example, under RIIO, the British distribution utilities face rewards and penalties of approximately five percent of their base distribution revenues (CEPA LLP 2013).

existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance, or areas where regulators see opportunities for greater efficiencies or reduced costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

> In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result pressures to reduce costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases and cost trackers.

> In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes. Performance metrics should be applied to the priority performance areas, and performance incentives should be designed to complement, offset, or mitigate existing financial incentives.

> In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

> In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

> In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

3. PERFORMANCE METRICS

3.1. Introduction

There are significant advantages of establishing performance metrics—even without administering financial incentives. Reporting utility performance facilitates regulatory oversight and encourages utilities to strive for better performance, as subpar performance is likely to result in negative public response and greater regulatory scrutiny. Implementing tracking and reporting metrics is straight-forward and low risk. It can be designed to present little administrative burden on either regulators or utilities, while providing valuable information.

3.2. Performance Dimensions That May Warrant Metrics

Performance incentive mechanisms have historically been used to help achieve traditional goals of reliable, safe, and low-cost utility service. Today, new incentives are being proposed to attain a whole new set of energy policy objectives, such as environmental quality, fuel diversity, fast-responding resources, and customer empowerment, to name a few.

For example, states throughout the West are facing stricter environmental standards for criteria air pollutants, water use, and carbon emissions, and many states are experiencing rapid growth in rooftop solar PV.[9] In response to these new regulations and the growth of distributed generation, utilities are investing billions of dollars in new renewable energy capacity[10] and transmission and distribution infrastructure (including smart grid technologies), and will need to procure significant amounts of resources to accommodate variations in net load (including demand response, advanced wind and solar control technologies, and storage).[11]

To ensure that utilities are operating efficiently and meeting energy policy goals, regulators may wish to track a variety of dimensions of utility performance, and possibly also implement financial rewards or penalties in areas where additional incentive is needed. The figure below highlights a variety of dimensions of utility performance that may warrant tracking and reporting or incentives. Performance dimensions generally fall into three categories: traditional goals, new business models, and environmental goals. Some aspects of utility performance have been important in more than one area;

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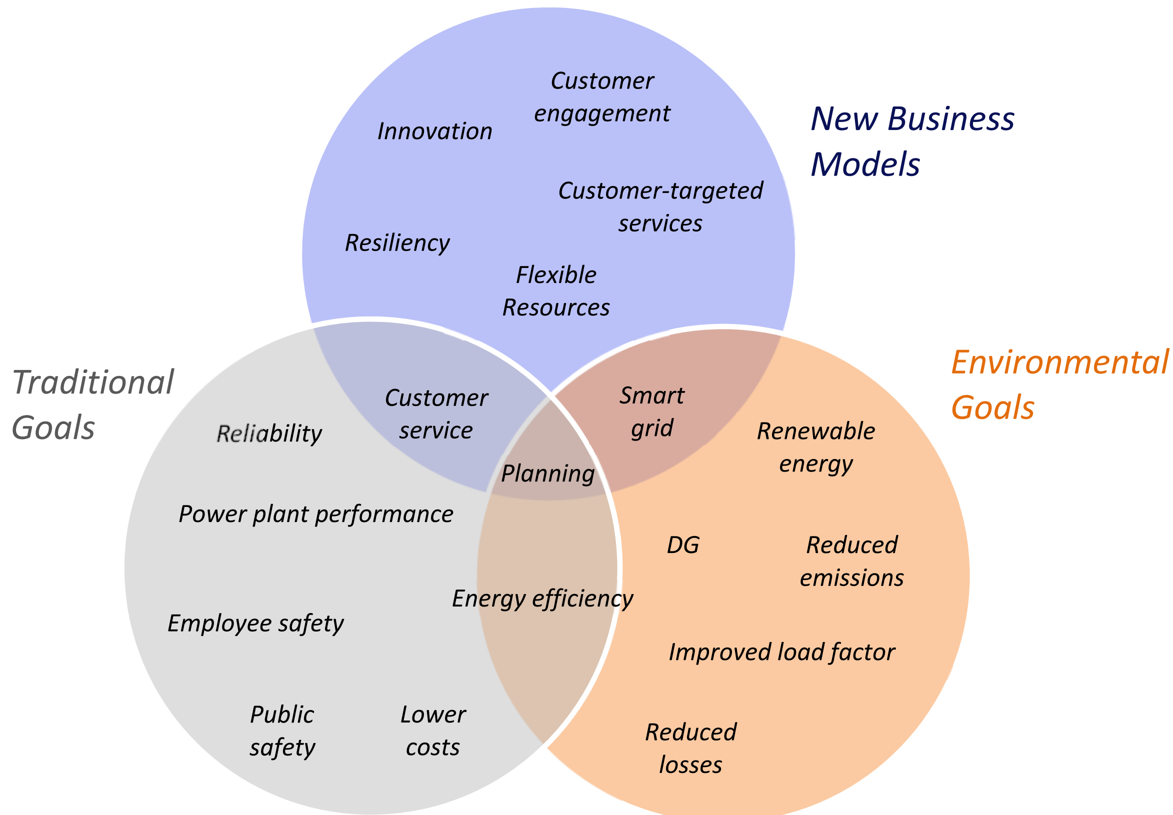
[9] Residential installations of PV are expanding at a rate of more than 50 percent year-over-year, with California, Arizona, and Colorado among the top states (SEIA/GTM Research 2013).

[10] The Western Electricity Coordinating Council (WECC) predicts that renewable resources in the West (excluding conventional hydro) will produce nearly 17 percent of the region's energy by 2022 (WECC Staff 2013).

[11] During certain times of the year, total system load net of solar and wind changes rapidly producing an effect known as the "duck curve." These very fast changes to net load (total load minus the output of variable resources) require fast-ramping resources to mitigate reliability impacts caused by the sudden appearance or departure of variable energy resources (Lazar 2014).

for example, successful implementation of cost-effective energy efficiency can reduce emissions associated with fossil generation (an environmental benefit) and defer or avoid new generation, capacity, transmission, and distribution resources, resulting in cost savings (a traditional focus of utility performance regulation). Planning has a critical role in informing regulatory outcomes across all three areas, and thus it takes a central location in the Venn diagram below.

Figure 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives



Traditional Performance Areas

Several aspects of utility performance have a long history of being tracked and reported to state utility commissions, federal regulatory agencies, or otherwise made publicly available. These traditional performance areas are reliability, safety, customer satisfaction, power plant performance, and costs; as indicated in Table 3.

Metrics for monitoring these traditional performance areas are generally well developed, and the data readily available. Where standard metric definitions exist and have been adopted by utilities, regulators may wish to track and compare performance across utilities within a state or across the region. (However, peer group comparisons may not be appropriate for the determination of rewards and penalties without controlling for differences among utilities. This is discussed in greater detail in later sections.)

Table 3. Traditional Performance Areas

Performance Dimension	Purpose
Reliability	To indicate the extent to which service is reliable and interruptions are remedied quickly
Employee Safety	To ensure that employees are not subjected to excessive risks
Public Safety	To ensure that the public is not subjected to excessive risks
Customer Satisfaction	To ensure that the utility is providing adequate levels of customer service
Plant Performance	To indicate the performance of specific generation resources
Costs	To indicate the cost of supply side resources

Innovative and Emerging Performance Areas

In order to address evolving industry challenges, regulators are beginning to focus attention on new aspects of utility performance, including overall system efficiency such as system load factor, use per customer, etc.; customer engagement (including tools to empower customers to better manage their bills); network support services; environmental impacts; and clean energy goals. Examples of these emerging performance areas and metrics for tracking them are provided in Table 4.

Table 4. Emerging Performance Areas

Performance Dimension	Purpose
System Efficiency	To indicate the extent to which the utility system as a whole is being operated more efficiently
Customer Empowerment	To indicate the extent to which customers are participating in demand-side programs or installing demand-side resources
Network Support Services	To indicate the extent to which customers and third-party service providers have access to networks
Environmental Goals	To indicate the extent to which the utility and its customers are reducing environmental impacts, particularly related to climate change

3.3. Defining Metrics

Simply defined, a metric is a standard of measurement. In assessing utility performance, metrics play a central role in enabling regulators to determine how well a utility is performing in the areas of interest. Defining a metric typically involves the following:

- Specific data definitions
- A precise formula used to quantify each metric

- Data collection and analysis practices and techniques, including identification of the entity responsible for collecting and reporting the data
- Requirements for measurement and reporting
- Verification techniques and entity responsible for verifying data

For example, a common metric for measuring reliability is the sustained average interruption duration index, SAIDI. The data include the average number of utility customers and the number of sustained outages, and may or may not exclude outages from major storms. However, to employ this metric, the definition of both a "sustained outage" and "major storm" needs to be clarified, the frequency of measurement (e.g., annual or quarterly) defined, and a verification process established.

Table 5 through Table 10 contain metrics for traditional performance areas that regulators may find useful for measuring utility performance, including metrics for reliability, employee safety, public safety, customer satisfaction, plant performance, and costs. Table 11 through Table 14 contain metrics for emerging performance areas, including system efficiency, customer engagement, network support services, and environmental goals.

These tables are intended to cover a wide range of issues of importance to regulators, but do not exhaust the universe of metrics that regulators may wish to consider. Nor are these metrics necessarily the "best" means of measuring performance in a certain area. The first step in determining which metrics will best serve the needs of a particular state is to articulate the policy goals that the state wishes to achieve. Regulators should then design metrics that are capable of accurately and reliably measuring progress toward these goals. The metrics includes in the tables below (and their formulas) provide examples of existing or potential metrics that could be implemented, but may not necessarily suit a particular jurisdiction's needs.

Examples of Innovative Performance Metrics

As the electric industry transforms, new metrics are being proposed to measure how well utilities meet evolving customer needs. Many of these existing or proposed performance metrics are described in more detail in the appendix, including:

- *Peak load reductions (Illinois)*
- *Stakeholder engagement (Illinois, Hawaii)*
- *Customers accessing energy usage portals (Illinois)*
- *Effective resource planning (Hawaii)*
- *System load factor (Illinois)*
- *Line loss reductions (UK, Illinois)*
- *Distributed generation interconnections (UK, Illinois, Hawaii)*
- *Cost of renewable energy (California)*
- *Carbon intensity (Hawaii)*
- *Renewable energy curtailments (Hawaii)*

See Appendix A for detailed case studies describing some of these metrics and performance incentive mechanisms.

Table 5. Reliability Performance Metrics

Metric	Purpose	Metric Formula
System Average Interruption Duration Index (SAIDI)	Indicator of sustained interruptions experienced by customers	Total customer minutes of sustained interruptions / total number of customers
System Average Interruption Frequency Index (SAIFI)	Indication of how many interruptions are experienced by customers	Total number of customer interruptions / total number of customers
Customer Average Interruption Duration Index (CAIDI)	Indicator of the length of interruptions experienced by customers	Total minutes of sustained customer interruptions / total number of interruptions
Momentary Average Interruption Frequency Index (MAIFI)	Indicator of momentary interruptions experienced by customers	Total number of momentary customer interruptions per year / total number of customers
Power quality	Indicator of voltage changes, which can cause damage to end use equipment and frequency deviations	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker; CPS 1 and 2 that measure frequency excursions

Table 6. Employee Safety Performance Metrics

Metric	Purpose	Metric Formula
Total Case Rate (TCR)	Indicator of employee injuries, fatalities, and productivity losses due to work-related incidents	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[12]
Days Away, Restricted, and Transfer (DART) case rate	Indicator of employee injuries, restrictions, and productivity losses due to work-related incidents	(Number of work-related days away from work and job transfers or restrictions due to work accidents times 200,000) / Employee hours worked
Days Away From Work (DAFWII) case rate	Indicator of employee injuries and productivity losses due to work-related incidents	(Number of work-related days away from work due to work accidents times 200,000) / Employee hours worked

Table 7. Public Safety Performance Metrics

Metric	Purpose	Metric Formula
Incidents, injuries, and fatalities (electric)	Indicator of incidents, injuries, and fatalities associated contact with the electric system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity
Emergency response time (electric)	Indicator of speed of response to emergency situations involving the electric system	Percent of electric emergency responses within 60 minutes each year
Incidents, injuries, and fatalities (gas)	Indicator of incidents, injuries, and fatalities associated with the gas system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause
Emergency response time (gas)	Indicator of speed of response to emergency situations involving the gas system	Average minutes for gas emergency response
Leak repair performance (gas)	Indicator of speed of response to non-emergency situations involving the gas system	Average days for repair of minor and non-hazardous leaks

[12] 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Table 8. Customer Satisfaction Performance Metrics

Metric	Purpose	Metric Formula
Call center answer speed	Indicator of customer ease of contacting utility	Percentage of calls answered within 30 seconds
Transaction surveys	Indicator of how well the utility is meeting customer needs based on recent contact with utility	Percentage of customers satisfied with their recent transaction with the utility
Customer complaints	Indicator of how well the utility is meeting customer needs	Formal complaints to commission (per 1,000 customers) over a set period. May also track complaints resolved.
Order fulfillment	Indicator of response time to service requests and outages	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled
Missed appointments	Indicator of how well the utility is meeting customer needs	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises
Avoided shutoffs and reconnections	Indicator of efficient provision of services to low income customers	Disconnects and reconnections avoided by customer percentage of income payment plans or other means
Residential customer satisfaction	Indicator of how well the utility is meeting the needs of residential customers	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index
Business customer satisfaction	Indicator of how well the utility is meeting the needs of business customers	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index

Table 9. Plant Performance Metrics

Metric	Purpose	Metric Formula
Fuel usage	Indication of the fuel consumption by specific generation resources	Quantity of fuel burned
Heat rate	Indication of the efficiency of specific generation resources	Average BTU per kWh net generation
Capacity factor	Indication of actual generation by a specific resource	Average energy generated for a period / energy that could be generated at full nameplate capacity

Table 10. Cost Performance Metrics

Metric	Purpose	Metric Formula
Capacity costs	Indicator of costs of peak consumption	Cost per kW of installed capacity
Total energy costs	Indicator of costs of all hours consumption	Expenses per net kWh
Fuel cost	Indicator of costs of fuel input	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs
Effective resource planning*	Indicator of efficacy, breadth, and reasonableness of resource planning process	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.
Cost-Effective Alternative Resources*	Indicator of system savings through use of cost-effective alternatives to traditional infrastructure	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 11. System Efficiency Performance Metrics

Metric	Purpose	Metric Formula
Load factor	Indication of improvement in system and customer load factors over time	Sector average load / sector peak load
		Monthly system average load / monthly system peak load
Usage per customer	Indication of customers' energy consumption changes over time	Sector sales / sector number of customers
Aggregate Power Plant Efficiency	Indication of the efficiency and availability of supply-side generation resources in total	System average BTU per kWh net generation (heat rate)
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)
		EFORd: variant of EFOR, measuring the probability that units will not meet generating requirements demand periods because of forced outages or derates
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings
Flexible Resources	Indication of the capacity of supply side resources to quickly respond to changes in net load	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)
System losses (electric)	Indication of reductions in losses over time	Total electricity losses / MWh generation, excluding station use
System losses (gas)	Indication of reductions in gas losses over time	Total gas losses / total sales

Table 12. Customer Engagement Performance Metrics

Metric	Purpose	Metric Formula
Energy efficiency (EE)	Indication of participation, energy and demand savings, and cost effectiveness of EE programs	Percent of customers per year
		Annual and lifecycle energy savings
		Annual and lifecycle peak demand savings (MW)
		Program costs per MWh energy saved
Demand response (DR)	Indication of participation and actual deployment of DR resources	Percent of customers per year
		Number of customers enrolled
		MWh of DR provided over past year
		Potential and actual peak demand savings (MW)
Distributed generation (DG)	Indication of the technologies, capacity, and rate of DG installations, and whether net metering policies are supporting DG growth	Number of installations per year
		Net metering installed capacity (MW)
		Net metering MWh sold back to utility
		Net metering number of customers
		MW installed by type (PV, CHP, small wind, etc.)
Energy storage	Indication of the technologies, capacity, and rate of customer-sited storage installations and their availability to support the grid	Number of installations per year
		MW installed by type (thermal, chemical, etc.)
		Percent of customers with storage technologies enrolled in demand response programs
Electric vehicles (EVs)	Indication of customer adoption of EVs and their availability to support the grid	Number of additions per year
		Percent customers with EVs enrolled in DR programs
Information availability	Indicator of customers' ability to access their usage information	Number of customers able to access daily usage data via a web portal
		Percent of customers with access to hourly or sub-hourly usage data via web
Time-varying rates	Indication of saturation of time-varying rates	Number of customers on time-varying rates

Table 13. Network Support Services Metrics

Metric	Purpose	Metric Formula
Advanced metering capabilities	Indication of metering functionality	Number of customers with AMI and AMR
		Energy served through AMI
Interconnect-ion support	Indication of DG installation support	Average days for customer interconnection
		Customer satisfaction with interconnect process
Third-party access	Indication of network access by third-party vendors	Open and interoperable smart grid infrastructure that facilitates third-party devices
		Third-party vendor satisfaction with utility interaction
Provision of customer data	Indication of customer access to relevant data	Customers able to authorize third-party access electronically
		Percent of customers who have authorized third-party access
		Third-party data access at same granularity and speed as customers

Table 14. Environmental Goals Performance Metrics

Metric	Purpose	Metric Formula
SO_2 Emissions	High-level indicator of emissions	Tons
Average NOx Rate	High-level indicator of emissions	lbs/MMBtu
CO_2 emissions	High-level indicator of emissions	Tons CO_2
Carbon intensity	Indicator of carbon emissions that accounts for changes in customers	Tons CO_2 / customer
System carbon emission rate	Indicator of carbon emissions that accounts for volume of generation	Tons CO_2 / MWh sold
Clean Power Plan (CPP) emission rate	Indicator of compliance with EPA's CPP	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))
Fossil carbon emission rate	Indicator of carbon emissions accounting for improved efficiency and dispatch of fossil resources	Tons CO_2 / MWh fossil generation
Fossil generation	Indication of reduction in fossil fuel use	Fossil MWh percent of total generation
Renewable generation	Indicator of development of renewable power	Renewable percent of total generation

3.4. Design Principles

The following design principles should be considered when establishing performance metrics. Metrics should be:

1. Tied to the policy goal
2. Clearly defined
3. Able to be quantified using reasonably available data
4. Sufficiently objective and free from external influences
5. Easily interpreted
6. Easily verified

These principles are discussed in more detail below.

Metrics Should be Tied to Policy Goals

To be useful, metrics should help stakeholders understand the degree to which policy goals are being achieved. Too often, metrics report data without conferring useful information. For example, if a policy goal is to improve the system load factor by reducing peak demand, it is not meaningful to simply report the number of customers enrolled in a demand response program, as this provides no information regarding whether these customers actually reduced demand, and by how much, during peak periods. To be useful, a metric should reflect whether or not the underlying policy goal is being met; e.g., whether peak demand has decreased over the prior year.

Metric Definitions Should be Unambiguous

How a metric is calculated should be defined in a way that leaves little ambiguity regarding precisely what data are included and excluded, the units of measurement, the frequency of measurement, and the methods used to analyze and report it. Failure to do so may impair meaningful comparisons of performance across years or utilities, while potentially increasing contention during proceedings (see Nevada case study in sidebar).

Where possible, metrics should be defined in a manner consistent with national or regional standards and definitions in order to facilitate comparisons across utilities. However, regulators should not be constrained by these definitions; similar metrics that report slightly different data may be more useful for determining whether utilities are achieving a policy goal. In such cases, data under both the standard definition and the jurisdiction-specific definition could be reported.

Careful attention to metric definitions is necessary to simplify data review, ensure that metrics will be reported consistently over time, and enable meaningful comparisons. The specificity required for data definitions should not be underestimated. For example, although there exists a common industry standard for measuring and reporting reliability performance, few utilities adhere to this standard.[13] Thus standard metrics such as System Average Interruption Duration Index (SAIDI) are actually often reported in different ways, with definitions of "major events" or the length of a "sustained interruption" varying across utilities and jurisdictions. In fact, sometimes these metrics are reported inconsistently even within a jurisdiction.[14]

Fuel Diversity in Nevada

Per Nevada administrative code NAC 704.9484, the Public Utilities Commission can grant critical facility (CF) status for the purpose of protecting reliability; promoting resource diversity; developing renewable energy resources; fulfilling specific statutory mandates; or promoting retail price stability. Owners of CFs may be granted special ratemaking treatment (e.g., deferral of incremental O&M costs) or other incentives (return on equity adder for the facility, or including construction work in progress in rates).

The criteria used to evaluate whether a facility meets the criteria for CF status have not been explicitly defined, however. This has resulted in ambiguity for resource developers, contentious proceedings, and uncertainty regarding whether policy goals are being achieved.

By 2010, all approved requests for CF status involved construction of gas-fired generation resources, leading to concerns about over-reliance on gas. Clearly articulated goals, metrics, and targets could have helped to avoid this over-investment in a single resource and reduced the litigation associated with related proceedings.

For more information, see PUC order dated July 28, 2010 in Docket Nos. 10-02009. 10-03022. and 10-03023.

Metrics Should be Able to be Quantified Using Reasonably Available Data

Data that are not readily available may be costly to collect. Making use of existing industry standards and generally available data can ease administrative burdens to regulators and utilities alike, and, where appropriate, can facilitate benchmarking utility performance against others. Fortunately, a large amount of data is already reported by utilities to the Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the North American Electric Reliability Corporation (NERC), and other entities. Specific data sources for many of the metrics presented in Tables 4 and 5 are provided in Appendix B.

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[13] The Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 is intended to increase consistency among utility reliability reporting practices, but adoption of the standard is voluntary. Many utilities report reliability metrics (such as SAIDI and SAIFI) using somewhat different data definitions (Eto and LaCommare 2009).

[14] For example, the Maryland PSC staff noted that "the Maryland utilities have not been consistent with their treatment of planned outages when reporting reliability metrics to the Commission. The investor-owned utilities report reliability metrics excluding planned outages and the cooperatives report reliability metrics including planned outages" (MD PSC Staff 2011, 6).

Metrics Should Be Sufficiently Objective and Largely Free from Exogenous Influences

Regulators may wish to track many metrics in order to better understand what is happening in their state's electric system. However, not all of these metrics are good indicators of utility performance. To evaluate how utilities themselves are performing, and particularly to administer penalties or rewards, the metrics chosen should be sufficiently objective and free from exogenous influences. Otherwise, factors that the utility has no control over can influence the results, obscuring the role that utility management played in the outcome.

For example, average customer bills can be a tempting metric to use to evaluate utility efficiency. However, average bills are impacted by numerous factors, ranging from fossil fuel prices, costs of steel and other commodities, weather, and the economy. These exogenous factors prevent average bills from serving as a sufficiently objective metric.

Objectivity does not necessarily mean that all data must be purely quantitative or measured using physical units. For example, customer satisfaction surveys can be designed to be sufficiently objective through the use of specific, targeted survey questions (see sidebar). Surveys can be conducted in phases over time so that no single event (e.g., a storm related outage) has too strong of an influence on the results.

Customer Survey Results as an Objective Metric

A number of states require utilities to report customer satisfaction survey results. In Massachusetts, poor customer satisfaction survey scores may lead to substantial financial penalties. The application of penalties to survey results was recently opposed by many Massachusetts utilities, who argued that surveys are too subjective. However, the Massachusetts Department of Public Utilities reaffirmed that surveys can provide sufficiently objective information, if designed and administered well.

To enhance the quality of information collected in the surveys, the Massachusetts survey was modified from a more general question regarding customer satisfaction to very specific questions about whether customers' issues were resolved after the first contact with the utility, and how easy it was to conduct business with the utility. The specificity of these questions helps to control for the influence of other factors (such as electricity rates or media coverage) on customers' responses.

See DPU Order dated July 11, 2014, Investigation by the DPU on Its Own Motion Regarding the Department's Service Quality Guidelines, D.P.U. 12-120-B

Metrics Should Be Easily Interpreted

Metrics that are readily interpreted generally provide stakeholders with a better understanding of utility performance. To improve interpretability, metrics should exclude the effects of factors outside of the utility's control to the extent possible. For example, a metric that measures the time required to interconnect distributed generation could be limited to include only the time from when the application is deemed complete to the time when the application is approved. This definition would thereby exclude any delays due to customer inaction.

Another means of improving interpretability is to use per-unit metrics to facilitate comparison across time and across utilities. Examples include percentages (e.g., percentage line losses), per-kWh (e.g., average emissions per kWh of generation), and per-customer (e.g., O&M costs per customer). For example, if the objective is to increase utility efficiency by reducing costs, a metric based on O&M costs per customer may be more informative than total O&M costs, as the number of customers may change over time.

Metrics Should be Verifiable

Data validity and reliability is essential for ensuring that utility performance is being accurately measured. For this reason, external verification of performance data is often relied upon, and the metrics chosen should lend themselves to such verification.

Where commissions have implemented performance tracking and reporting, commission staff frequently review and verify data, but independent third-party evaluators are also used, particularly when financial rewards or penalties are at stake. Greater use of third-party evaluators may help to prevent performance incentive gaming, such as that which occurred in California in the 1990s-2000s (see sidebar).

The use of straight-forward data collection and analysis techniques should be used where possible, as it improves transparency, enabling regulators and other stakeholders to more easily determine the data's accuracy. This makes manipulation of data more difficult and reduces the costs of oversight, as there is less need to hire specialized consultants (Costello 2010). In contrast, metrics that require complex data collection or analysis techniques make review and interpretation more difficult while increasing costs.

Gaming of Performance Incentive Mechanisms in California

In the late 1990s and early 2000s, Southern California Edison operated under a PBR plan with performance incentive mechanisms for customer satisfaction (as measured through surveys) and employee health and safety. The problems with the customer survey were many, but the most serious instances arose when utility employees sometimes falsified customer contact information to screen out customer interactions that might result in negative customer satisfaction surveys.

The employee health and safety performance mechanism was similarly problematic. Not only did the incentive mechanism actually discourage workers from reporting injuries in order to avoid jeopardizing safety incentive compensation for their group, but some supervisors participated in or encouraged under-reporting of data. Methods used to disguise injuries and avoid internal reporting included: employee self-treatment; treatment by personal physicians rather than the company doctor; and timecard coding of lost time as sick days or vacation. See Appendix A for further details.

3.5. Dashboards for Data Reporting

To be useful, performance metric data must be presented in an easily accessible, up to date, and properly contextualized manner. Without context, such as comparison of current performance to historical trends or benchmarks, utility performance data convey little meaningful information to regulators and stakeholders. Similarly, when performance statistics are not aggregated in a central location, but are provided only in filings made in various dockets on different reporting cycles, it becomes difficult and time-consuming to develop a holistic view of utility performance across multiple dimensions.

Data dashboards provide a means of collecting utility performance information in a central location and presenting the data in a transparent and meaningful way. A designated website—hosted either by the utility or the commission—provides a useful forum for displaying performance information, ideally through both interactive graphs and downloadable data. Dashboards allow data to be compared across years and between utilities. If a performance target is set, the dashboards enable all users to quickly determine whether the utility is meeting or failing to achieve the targets. Data dashboards should complement, rather than be a substitute for, prudency reviews.

Dashboards should be:

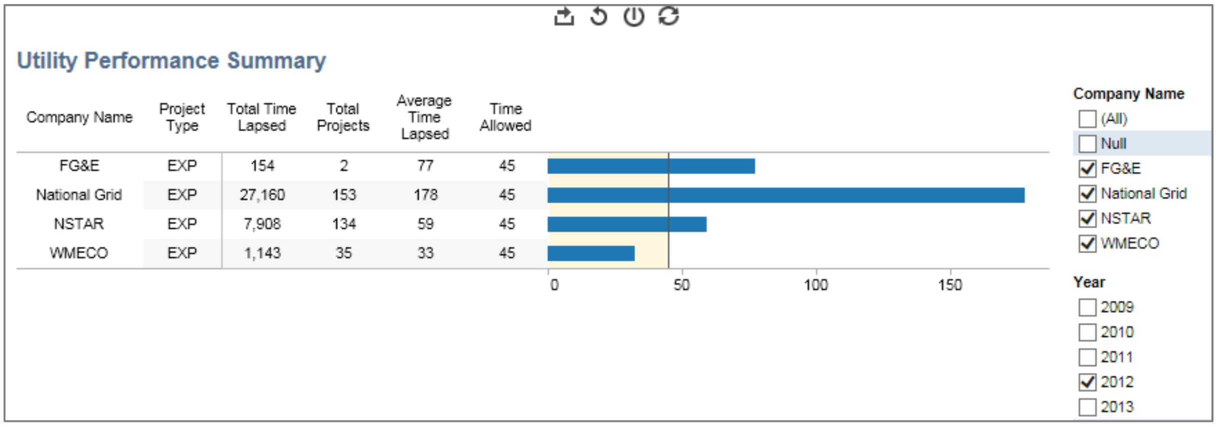
- **Accessible:** Performance data should be presented in a publicly-accessible manner, such as on a designated website, and should include a means for downloading the underlying data.
- **Contextualized:** Performance targets, historical performance data, peer performance, and explanations of any major events that impacted performance should be included in the data presentation.
- **Clear and concise:** Performance should be presented in graphs that are clear and easily interpreted. An explanation of how the metric is calculated should also be included. Highly technical terms should be adequately defined or avoided.
- **Comprehensive:** The dashboard website should provide data and graphs for all aspects of utility performance that the commission wishes to monitor.
- **Up to Date:** The data and graphs should be updated frequently. Many metrics may warrant quarterly updates, while others should be updated at least on an annual basis.

The Massachusetts Department of Energy Resources' (MA DOER) interactive graphs regarding interconnection of distributed generation provide an example of how such data can be effectively displayed and communicated to stakeholders. For example, Figure 3 shows a screen shot of one of the interactive graphs. The text accompanying the graph states:

> This chart helps you answer the question "On average how are utilities performing with regard to expedited projects that have not received a supplemental review?" Similar to the metric used in the DPU-approved Timeline Enforcement Mechanism (DPU 11-75-F), the average time lapsed is accounted for by dividing the total utility work time lapsed by the total number of projects by utility. Please note that only expedited projects without supplemental reviews, but with an "Interconnection Agreement Sent" date, are included. The other project types are not represented in this chart.

Users can select different combinations of utilities and data years, and are able to export the graph and download the underlying data. The vertical line in the graph demarcates the maximum interconnection time allowed and enables users to quickly determine whether a utility is meeting the target.

Figure 3. MA DOER Interactive Dashboard on Distributed Generation Interconnection Time

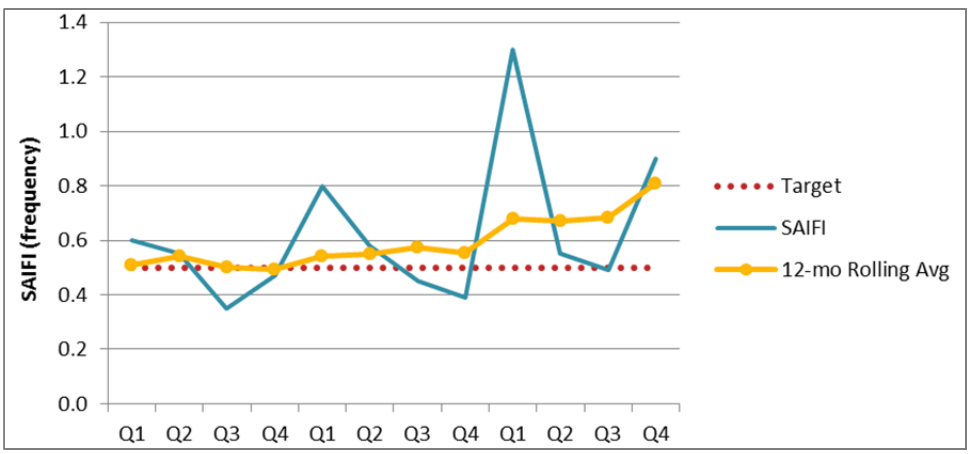


Company Name	Project Type	Total Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	EXP	154	2	77	45
National Grid	EXP	27,160	153	178	45
NSTAR	EXP	7,908	134	59	45
WMECO	EXP	1,143	35	33	45

Source: Massachusetts Department of Energy Resources, Interconnection Utility Performance Summary Website. https://sites.google.com/site/massdgic/home/interconnection/utility-performance-summary[15]

Static graphs that display utility historical performance are also helpful. For example, the graph below presents hypothetical data for the frequency of utility outages, reported on a quarterly basis. Additional examples of data dashboards are provided in Appendix C.

Figure 4. Example Dashboard for Utility Outage Frequency



In sum, data dashboards can be an extremely useful tool for enabling regulators and other stakeholders to quickly review utility performance across a large number of performance areas.

[15] Note that although the interactive nature of the graphs is very helpful for comparing utility performance across years and utilities, the graphs appear to only display properly with Internet Explorer. In contrast, static graphs may have fewer technical issues.

4. PERFORMANCE TARGETS

A performance target defines the precise level of service or output that a utility is expected to achieve during a particular time period. Targets may be used simply to provide guidance for a utility, with neither penalty nor reward attached. Performance targets can also be used as the basis for providing a utility with a financial incentive to achieve desired outcomes.

4.1. Design Principles

The following design principles should be considered when setting performance targets:

1. Tie targets to regulatory policy goals
2. Balance costs and benefits
3. Set realistic targets
4. Incorporate stakeholder input
5. Use deadbands to mitigate uncertainty and variability
6. Use time intervals that allow for long-term, sustainable solutions
7. Allow targets to evolve

These principles are discussed more below.

Tie the Target to the Ultimate Policy Goal

Consider what level of performance is necessary to achieve policy goals, and state this explicitly. Doing so will help stakeholders evaluate whether performance targets are being set in a manner that moves toward achieving these policy goals and will help maintain momentum in that direction, while also allowing stakeholders to better determine when the underlying policy objective—as opposed to simply meeting the target—has been achieved.

Balance Costs and Benefits

Balance the costs to customers of achieving the target with the benefits to customers. Ratepayer surveys can help to identify ratepayers' priorities and how much they are willing to pay for higher levels of utility performance. For example, a 2010 survey of Ontarians found that 89 percent of residential customers were satisfied with current levels of electric reliability, and more than half of customers were not willing to pay more for increased reliability (Pollara 2010).

In theory, the optimal level of performance is obtained where the marginal benefits from improved performance are equal to the marginal costs of providing that increased level of performance. As explained by Baldwin and Cave,

> "as quality increases it becomes more expensive to raise it further; hence the marginal cost of quality improvement rises as quality rises. In contrast, as quality rises, the extra benefit consumers get from a further increase in quality declines. These two factors determine an optimal level of quality, where marginal benefit (to the customer) and marginal cost (to the utility company) are equal" (Baldwin and Cave 1999, 253).

Identifying the optimal level requires knowledge of both the utility's marginal cost curve, as well as customers' willingness to pay for different levels of reliability. Norwegian regulators have used surveys to construct a willingness to pay curve, and have internalized these values in the utility's decision-making process (see sidebar) (Growitsch et al. 2009). The Alberta Utilities Commission recently acknowledged the value of such customer willingness-to-pay surveys, but chose instead to rely on results from already-available customer satisfaction surveys to determine the acceptability of current levels of reliability for customers (Alberta Utilities Commission 2012).

In practice, especially for some performance areas, it may be difficult to quantify the marginal costs and benefits to determine the optimal performance target. In such cases, regulators may want to at least apply a qualitative assessment of what the costs and benefits to customers might be.

For example, if a commission were to establish a performance target related to the interconnection of distributed generation (in terms of average days for customer interconnection), it may be too burdensome to quantify all of the costs and benefits associated with reduced interconnection waiting time. Nevertheless, regulators, utilities, and others may be able to make a qualitative assessment of the value of increased distributed generation relative to the cost of reducing interconnection waiting time.

Balancing Reliability Costs and Benefits in Norway

Norway uses revenue cap regulation to provide a set amount of annual revenues to its electric utilities. Under this regulatory framework, utilities retain any savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, Norwegian regulators have internalized the costs of outages into the utility's profit-maximization function. This is done by adjusting utility revenues each year based on the costs of outages to customers.

If the utility reduces outages above a baseline level, it receives higher revenues the following year. In contrast, if outages increase, revenues are reduced. The amount of the increase or decrease in revenues is based on customers' willingness to pay for reliability, calculated separately by each customer sector. To maximize profits, the utility will increase expenditures up to the point where the marginal cost of increased reliability is equal to customers' willingness to pay (also referred to as the marginal benefit). The Norwegian utilities therefore face an incentive to provide the socially optimal level of reliability, where marginal costs are equal to marginal benefits.

Set a Realistic Target

The performance target should be realistically achievable by a well-managed utility. If utility performance is currently satisfactory, then the performance target could be set to simply maintain recent performance levels (assuming that future operating conditions will be similar to current conditions). If a higher level of performance is desired, a reasonable target can be developed based on (1) historical performance, (2) peer utility performance, (3) frontier methods such as data envelopment analysis, or (4) utility-specific studies.

1. Historical performance. Under the first method, a utility's previous performance over a set period of time—for example, the past ten years—is used to set the target. This method presumes that the data have been collected in the past and are readily available; that there has been little fundamental change in the key factors influencing utility performance; and that historical performance was satisfactory. Although historical data may be useful in setting initial performance targets, continuing to use historical data may be problematic due to the ratchet effect. The ratchet effect refers to the performance standard being raised if the utility performs well, making it harder for the utility to meet the standard in the next period, and diluting the incentive for the utility to improve performance in the current period (Comnes et al. 1995).

2. Peer utility performance. The second method uses peer groups to determine the performance target. If a peer group is used, effort should be made to account for the utility's unique circumstances that may impact the ability of the utility to reasonably achieve the target, or recent external factors that significantly impacted performance, such as a major storm.[16] This can be done through one of two ways: choosing a peer group that is similar to the utility in question, or using econometric techniques to control for certain variables.

   Direct comparison with peer utilities is referred to as "indexing." To identify the relevant group of peer utilities, econometric analysis can be performed to identify the most significant variables affecting utility performance, such as the geographic region and operating scale. Then utilities that are similar in these respects may serve as a suitable point of comparison. Another means of identifying a peer group is through cluster analysis, which groups utilities according to certain characteristics using statistical software (Shumilkina 2010).

   Where data on a variety of external factors that impact performance are available, econometric modeling can be used to control for these factors and provide an indication of "average" utility performance. However, the accuracy of the model is highly dependent upon inclusion of the correct variables and specification of the correct functional form (Shumilkina 2010). Failing to include data on a relevant variable can lead to omitted variable bias, yet collecting all of the relevant data (on utility characteristics, weather, age of investments, etc.) can be time consuming and prone to error.

3. Frontier methods. A third method of analysis is frontier analysis, a form of which is Data Envelopment Analysis (DEA). DEA measures technical efficiency of firms based on a sample of

[16] Although reliability reporting and performance targets generally exclude the impacts of major storms, the definition of "major storm" varies from state to state.

firms, their input use, and their outputs. The analysis identifies the most efficient firms and creates an efficiency frontier based on these firms' input usage per unit of output. Other firms are then assigned a score based on their efficiency relative to the efficiency frontier (Shumilkina 2010). Factors that are outside of a utility's control should be taken into account in the DEA analysis, but this is not easily done. This technique also suffers from a lack of internal validation, such as misspecification tests or goodness-of-fit statistics. Nevertheless, DEA analysis has been used by energy regulators to determine price and revenue requirements for utilities in Finland, Norway, the Netherlands, Germany, Austria, and Australia (Australian Competition & Consumer Division 2012).

4. <u>Utility-specific studies</u>. Finally, regulators can use utility-specific economic and engineering studies to set targets. For example, integrated resource plans may provide detailed cost and benefit information regarding certain resource investments under specific planning assumptions. Energy efficiency and demand response potential studies can identify the amount of investments that would be cost-effective for the utility to make. Production cost simulations have been used to model efficient dispatch, operation, and purchasing decisions, providing benchmarks against which utility performance can be measured.[17] These studies can help regulators identify and define specific resource investment targets and costs.

Regardless of the manner in which targets are set, regulators should minimize the ability of the utility to game target-setting. If there is an expectation that performance targets will be set at a future date based on historical data, the utility has an incentive to underperform until the target is set in order to establish a more lenient target. Econometric and frontier models can present challenges in terms of transparency, as these models are complex and require careful specification (Shumilkina 2010), which could lead to manipulation of the model to achieve the desired results.[18] Finally, basing targets on utility-specific studies that have been developed by the utility may create an incentive for the utility to overstate cost forecasts in order to deliver projects at costs that are below the target.

Incorporate Stakeholder Input

Allowing for meaningful stakeholder input during the process of setting targets is likely to result in targets that meet state regulatory goals, result in desired outcomes, and minimizes the potential for manipulating or gaming the targets. In addition, a meaningful stakeholder process can enable

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[17] San Diego Gas & Electric (SDG&E) operated under a generation and dispatch performance-based ratemaking (PBR) incentive plan from 1993 to 1997, and earned rewards during all three years that the plan was in operation. Year 1 and Year 2 awards were reported in SDG&E's *Electric Generation and Dispatch PBR Mechanism Final Evaluation Report*, April 1998, submitted pursuant to D.97-07-064 in A.92-10-017, and Year 3 awards were adopted in D.98-12-004 as part of the adopted settlement agreement.

[18] Econometric modeling requires that the modeler make a number of decisions regarding functional form, whether certain data points represent true outliers that should be excluded, whether to choose a model based on parsimony or goodness-of-fit, etc. These choices may all impact the final result and should thus be carefully reviewed.

stakeholder buy-in, and enhance the legitimacy of targets. Stakeholder input also reduces the likelihood of contentious disagreements once performance incentives are implemented and rewards and penalties start to be applied.

Energy efficiency performance standards sometimes use this approach, with good results. Some states have established advisory councils or collaboratives to help oversee and provide input to the efficiency program design and implementation, including the design and implementation of efficiency performance standards (e.g., Connecticut, Massachusetts, and Rhode Island – see sidebar). The stakeholders in these councils and collaboratives provide a considerable amount of input and review to the energy efficiency programs, which enables them to determine whether a particular performance incentive savings target is reasonable, or will be too easy or difficult to achieve. The stakeholders represent a broad range of views, including utility representatives, consumer advocates, environmental advocates, state agencies, and efficiency experts, which increases the chance that efficiency targets will be balanced and reasonable.

Stakeholder Engagement for Efficiency Standards

Efficiency councils have been established in Connecticut, Massachusetts, and Rhode Island—three of the leading states providing cost-effective efficiency programs. There are several key factors that make these three councils especially effective, including:

- *A broad representation of stakeholder interests.*
- *Frequent, well-organized meeting and communication systems to allow full access to information and debate.*
- *Efficiency experts available to provide technical support, with sufficient funding.*
- *Meaningful oversight by regulators, including a process where stakeholders can bring issues for resolution.*

Additional information is available at:

Connecticut - http://www.energizect.com/about/eeboard

Massachusetts - http://ma-eeac.org/

Rhode Island - http://www.rieermc.ri.gov/

Use Deadbands to Account for Uncertainty and Variability

Deadbands create a neutral zone around a target level in which the utility does not receive a reward or penalty. Deadbands can help to account for uncertainty regarding the optimal performance level, as well as allow for some performance variance based on factors outside of the utility's control (see sidebar for an example from Hawaii).

How large should deadbands be set? Deadbands are frequently set at one standard deviation of historical performance, but may be larger or smaller based on sample size and the tolerance for error. That is, if a large amount of historical data is available, then one standard deviation is likely to capture most of the normal variation in utility performance. If the sample size is small, for example three observations, then one standard deviation may not be large enough to capture the normal variation in utility performance. In such cases, a confidence interval can be constructed using the sample data and the regulator's desired level of confidence that the interval will sufficiently represent the range of normal variation.[19]

Use Time Intervals That Allow for Long-Term, Sustainable Solutions

The timeframe for measuring performance can impact the compliance strategies that the utility implements. If performance is measured only over a short timeframe, such as over one year, the utility has an incentive to implement solutions that can be quickly implemented, but may only have short-term benefits. In some cases, these short-run solutions may in fact be contrary to long-term sustainability. For example, a utility may be encouraged to compromise safety in order to achieve short-term economic goals.

In contrast, solutions that are optimal for the long-term may result in slow but steady improvement. For example, implementing sound maintenance and operational practices will result in long-term safety and economic benefits, but may not achieve short-term capacity factor targets. Thus performance measurements over the longer-term, such as the use of three-year rolling averages, may better encourage the utility to adopt sound long-term practices (NRC 1991).

Deadbands for Heat Rate Targets to Account for Integration of Renewables

Many states allow utilities to recover fuel and purchased power costs through automatic pass-through mechanisms. To ensure that utilities retain an incentive to operate their power plants efficiently, some states have conditioned fuel cost recovery upon power plant performance factors. For example, Hawaii's Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor.

Although Hawaii's ECAC encourages maintaining the thermal efficiency of thermal generators, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

See HECO Final Revised Tariff Sheet Nos. 63-63E, filed on July 24, 2012, in Docket No. 2010-0080

Allow Targets to Evolve

In general, once a target is set, it should be adjusted only slowly and cautiously in order to provide utilities with the regulatory certainty required to make long-term investments. However, targets may need to evolve over time for two reasons. First, if performance needs to be improved, it may not be possible for the utility to immediately achieve the desired level of performance, as noted above. Some problems may take years to fully remedy, despite the utility undertaking immediate actions to remediate the situation. In such cases, the performance measurement time interval can be lengthened, or targets can be set to become more stringent over time, providing the utility with a glide path for achieving the ultimately desired level of performance.

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[19] For more information on this approach, see Lowry et al. 2000.

Second, a target may need to evolve over time as technologies and policy goals evolve, or as the operating environment changes significantly. For example, smart grid investments may be able to dramatically improve outage duration rates. Therefore, if a utility makes significant investment in new smart grid technologies, then any reliability performance targets for that utility should be reviewed, and perhaps modified, to reflect the implications of the new technologies.[20]

[20] In addition, if the utility is using improved reliability as part of the justification for such smart grid investments, then the performance targets can be used to ensure that those benefits are actually achieved.

5. Financial Rewards and Penalties

5.1. Design Principles

Once performance targets have been defined, regulators can establish incentives to further induce the utility to accomplish the desired outcomes. Rewards and penalties are generally financial in nature, although other forms of incentives may be used.[21]

The following design principles should be considered when setting financial rewards and penalties:

1. Consider the value of symmetrical versus asymmetrical incentives
2. Ensure that any incentive formula is consistent with desired outcome
3. Ensure a reasonable magnitude for the incentive
4. Tie incentive formula to actions within the control of utilities
5. Allow incentives to evolve

Value of Symmetrical versus Asymmetrical Rewards and Penalties

Financial incentives are frequently designed to be symmetrical, in order to provide balance and to both discourage poor performance and encourage exemplary performance. Symmetrical incentives generally also mirror more closely how a utility would be compensated in a competitive environment. However, in some cases asymmetrical incentives may be more appropriate than symmetrical ones.

Penalty-only incentives may be appropriate when the outcome is either an essential requirement for the utility, or when performance above target outcomes provides little additional benefit to ratepayers. For example, customers might not be willing to pay for incremental improvements in reliability beyond the target level, particularly if customers would be required to pay for any reliability improvements through both rates (to recover utility expenses) and performance rewards. At the same time, utilities have a clear obligation to provide sufficient levels of reliability, therefore unsatisfactory performance might

Asymmetrical Incentives in Alberta

In a 2012 order, the Alberta Utilities Commission rejected providing utilities with a positive performance incentive for exceeding service quality, writing "…in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher price for a service quality level that they may not want or cannot afford" (Alberta Utilities Commission 2012, 194–195).

[21] For example, the UK allows expedited regulatory treatment of utility business plans for business plans that are well executed. This offers utilities the benefits of reduced regulatory burdens and risks. In addition, the UK uses "reputational" incentives, where utilities' success in reducing carbon emissions is compared and made publicly available.

warrant the applications of penalties. See the sidebar for an example of asymmetrical incentives in Alberta.

In other cases, it may be beneficial to administer incentives on a positive basis only. This is common for energy efficiency incentives where any megawatt-hour of energy saved through a cost-effective efficiency program results in a benefit to ratepayers. In addition, reward-only incentives tend to encourage utilities to be more innovative, and may result in more collaborative and less adversarial processes (NY PSC 2012).

Ensure Incentive Formula Is Consistent with Desired Outcome

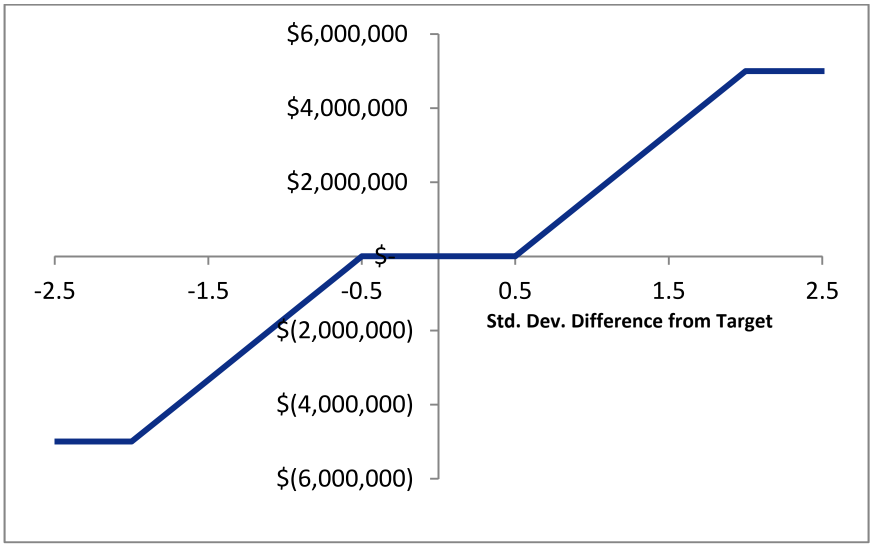
Incentive formulas can take numerous forms, including linear, quadratic, and step functions. It is important that the formula (and the shape and slope) of the incentive is consistent with the desired outcome and supports appropriate utility performance. The shape and slope of the formula determine how quickly the curves reach the maximum reward or penalty as performance deviates from the target (or the ends of the deadband). Below we present several possible incentive formulas and some of their benefits and drawbacks. Each graph shows how rewards or penalties (vertical axis) change as performance deviates from zero to two standard deviations from the target.

Linear Function with Deadband

Figure 5 depicts an incentive formula that has a deadband of 0.5 standard deviations, measuring how much performance varies from the average, on either side of the target. After 0.5 standard deviations, penalties and rewards increase in a linear fashion up to a maximum of $5 million. This formula is simple to understand and administer, and the deadband helps to control for normal fluctuations in performance due to factors that are outside the control of the utility.

A potential drawback is that a utility may be induced to perform at a level close to 0.5 standard deviations below the target, since such under-performance would not result in a penalty. The utility would especially have an incentive to operate close to -0.5 standard deviations from the target if the target is based on a rolling average of historical performance. This highlights the importance of monitoring utility behavior and making adjustments as necessary, such as narrowing the deadband over time, or delinking performance targets from historical performance.

Figure 5. Hypothetical Linear Formula with Deadband



<u>Quadratic Function</u>

A quadratic function (also referred to as a "parabolic function") can also be designed to provide increasing rewards or penalties as performance deviates from the target, but the rewards or penalties increase more slowly. Figure 6 presents a simple linear incentive function, as well as a quadratic incentive function with the same end points and central target.[22] As indicated, a quadratic formula acts similar to a deadband by providing little incentive near the central target. A quadratic function also results in an increasing slope as the performance deviates from the performance target.

Massachusetts has used a modified quadratic formula since 2001. In its order approving the formula, the Department of Public Utilities wrote: "While a linear formula may have the perceived advantage of simplicity, the Department considers a non-linear formula provides a stronger link between a utility's performance and the consequences of it failing to meet [service quality] measures" (MA DPU 2000, 25).

The formula for the quadratic function uses four inputs:

- Maximum reward or penalty (e.g., $5,000,000)
- Actual utility performance (e.g., a score of 1.75)
- A target (e.g., a score of 1.0)
- The standard deviation, σ (e.g., 0.5)

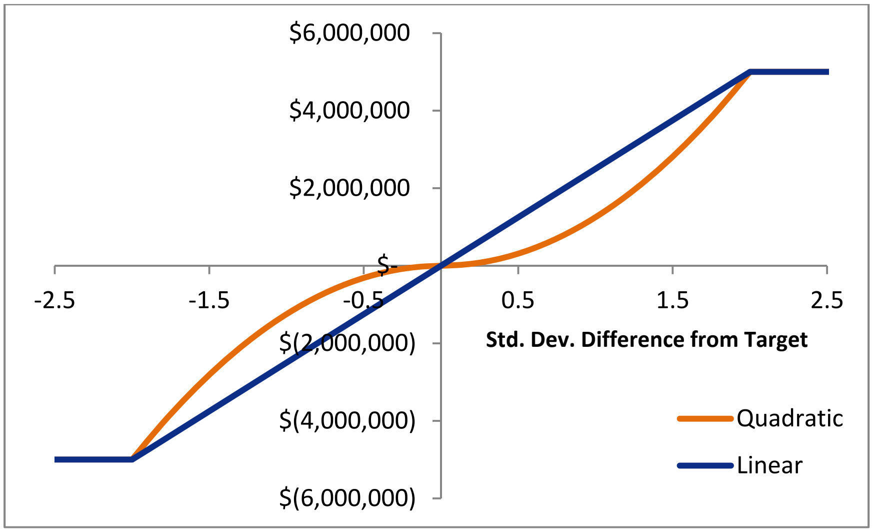
Penalties and rewards are maximized at two standard deviations from the target. A scalar of 0.25 is used to constrain the scores to values between 0 and 1, which is then multiplied by the maximum incentive.

[22] A linear function does not square the standard deviation difference from the target and uses a scalar of 0.5.
Reward or penalty = [(performance – target)/σ] x (0.5) x (maximum reward or penalty)

Reward or penalty = [(performance – target)/σ]^2 x (0.25) x (Maximum reward or penalty)

Using the example values from above: [(1.75 – 1.0)/0.5]^2 x (0.25) x $5,000,000 = $2,812,500

Figure 6. Quadratic Function Compared to a Linear Function

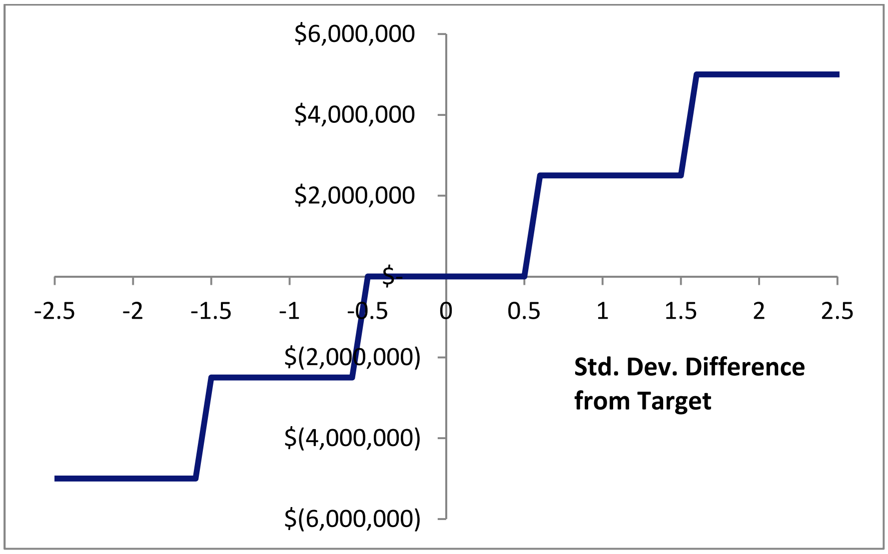


<u>Step Functions</u>

Step functions can be simple (e.g., two steps), or complex (multiple steps). Either way, the utility receives no incentive until it reaches a certain level of performance, at which there is a sharp change in the reward or penalty it receives. For example, in Figure 7 the utility receives no reward until it performs at 0.5 standard deviations above the target, at which point it receives a reward of $2.5 million. It continues to earn only $2.5 million until performance reaches 1.5 standard deviations above the target, at which point the reward increases to the maximum of $5 million.

Step functions are common and can be easy to administer, but they have several important drawbacks. When the amount of the penalty or reward can change dramatically with only a small change in performance (e.g., when performance increases from 0.49 standard deviations to 0.5 standard deviations from the target), the performance evaluation process can become very contentious. In addition, such sharp thresholds may induce a utility to engage in unsafe or unsound practices in order to avoid a large penalty or receive a large reward.

Figure 7. Hypothetical Step Function



Ensure a Reasonable Magnitude for the Incentive

When establishing the appropriate magnitude of financial incentives, regulators should generally seek to balance two competing objectives. Financial rewards and penalties should be large enough to capture utility management's attention and provide sufficient motivation to reach the desired outcome. On the other hand, rewards and penalties should not be disproportionate to the costs and benefits of the desired outcome. The reward should not unduly reward or penalize the utility, and rewards should not offset the benefits to ratepayers.

Performance incentive mechanisms should include a cap on the maximum penalty or reward, in order to ensure that the magnitude of the incentive will remain within a reasonable bound. Regulators should also consider the size of rewards and penalties within the context of the magnitude of existing incentives to ensure existing incentives and new incentives are properly balanced.

For utilities that are provided with multiple performance incentives, it is important to consider the potential impact on the total reward or penalty that might be applied. The total financial impact on a utility will depend on both the magnitude of the rewards and penalties and the likelihood of being assessed those rewards and penalties.

When establishing the magnitude of financial rewards and penalties, regulators may also need to consider the particular financial circumstances of the utility involved. This becomes especially important if the magnitude of the combined penalties and rewards are large enough to significantly impact the utility's financial position. Financial analysts and utility management typically pay special attention to the utility's financial position, thus it is important to recognize the financial implications of the penalties and rewards. This may involve several considerations:

- Financial analysts typically assess the risk associated with utilities, as well as the risk associated with regulatory systems and new regulatory measures. Therefore, it is important that the performance incentive mechanism and the potential financial impacts are clearly defined and transparent.

- Many utilities motivate managers and employees with incentive systems based upon stock options and prices. If the performance incentives have a significant effect on stock prices, then this provides additional, personal incentives to those employees to help meet performance goals.
- One thing that might help place the magnitude of rewards and penalties in perspective is to present them in financial terms, such as in terms of basis points on the return on equity, or in terms of equivalent cents per share on utility stock prices. Presentation of financial incentives is discussed briefly in the subsection below.

Further, rewards and penalties should always be proportionate to the importance of the performance goal to ratepayers. In general, incentive payments should not exceed the net benefits to ratepayers.

Presentation of Financial Incentives

Rewards and penalties can be expressed in several different equivalent units to help place their magnitude in context. For example, they can be presented as dollars, cents per share, basis points of return on equity (ROE), percent of non-fuel operating expenses, percent of base revenues, or percent of total earnings. The table below demonstrates how an incentive amount of $2.5 million could be presented in order to help stakeholders understand the magnitude of the incentive in relation to the utility's return on equity, operating expenses, cents per share, and percent of earnings. Total earnings can also be shown to provide context.

Table 15. Hypothetical Presentation of Financial Incentives in Different Units

Maximum Reward or Penalty	Equivalent Basis Points	Equivalent % of T&D Revenues	Equivalent cents/share	Percent of Pre-Tax Earnings	Total Pre-Tax Earnings
$2,500,000	25	0.9%	2.47	3.1%	$80,645,000

Presenting financial rewards and penalties in multiple units is useful during the process of setting the financial incentives. However, administration of the incentives is generally simplest when done as dollars, as other units can be administratively complex and result in perverse incentives. For example, positive incentives that are set in terms of ROE basis points could provide an incentive for a utility to increase rate base. See Appendix A for an example of the perverse impacts of an ROE adder for certain investments.

Tie Incentives to Actions and Outcomes within the Control of Utilities

Financial incentives should be based upon actions and outcomes that are within the control of the utility. First, if an action or outcome is beyond the control of the utility, then the performance incentive would have little to no effect on achieving the desired outcome, and therefore should not be applied at all. Second, it is unfair for customers to pay for utility rewards that are not a result of utility actions. Third, it is unfair to penalize utilities for outcomes that are beyond their control.

While this principle seems obvious and important, it can be difficult to hold to it in practice for some performance areas and metrics. Some events might be beyond a utility's control (e.g., the incidence and types of severe storms), but there may be things a utility can do to mitigate the implications of those events (e.g., by having effective emergency preparedness and emergency response programs).

Some elements of utility performance might be beyond a utility's control but may appear to be reasonable to include in an incentive formula. For example, some states have established "shared savings" incentives, where utilities are allowed to keep a small portion of the savings that they achieve as a result of improved power plant performance. This approach makes intuitive sense because customers can be expected to experience only net benefits as a result of the incentive, and ideally the majority of the net benefits. However, the magnitude of the savings from such incentives is often based on avoided fuel costs, which can fluctuate wildly for reasons completely beyond the control of the utility. As a result, utilities can experience undue windfalls or penalties. (See Appendix A for a discussion of the financial incentive for the Palo Verde nuclear power plant, which was based on avoided power costs. These avoided costs, and thus the financial incentive, skyrocketed during the California Energy Crisis in 2000).

In some instances it may be appropriate to provide financial incentives for actions that are only partly within a utility's control. For example:

- Regulators could provide all utilities in a multi-utility state with rewards if a statewide energy efficiency goal is met. A reward based on achievement of a statewide goal has two effects: (a) it encourages utilities to work together and share best practices; and (b) it provides an incentive for utilities to continue to pursue the statewide goal, even if they are clearly not going to meet their individual utility target.
- Regulators could provide utilities with rewards for supporting other initiatives regarding efficiency standards, building codes or commercialization of clean energy technologies. Utilities can have a significant influence on such statewide initiatives, even if they are partly or mostly beyond their control.
- Regulators could provide utilities with rewards for achieving certain energy policy, public interest, or societal goals that are partly beyond utility control, such as reducing the fuel burden on low-income customers or meeting economy-wide pollution targets.

Allow Incentives to Evolve

As with other aspects of performance incentive mechanisms, financial incentives may need to be adjusted over time. Financial incentives are sometimes adjusted when the magnitude of the incentive is found to be unreasonably large or small, or the basis for the financial incentive (e.g., avoided fuel costs) is found to be excessively volatile, resulting in excessive penalties or rewards.

Excessive penalties and rewards can sometimes be addressed easily, such as with a cap on rewards or penalties. In other cases a correction might require fundamental redesign of the incentive mechanism, including a full stakeholder process. While regulators should expect performance incentives to evolve over time in response to lessons learned in practice, it is also important to make any adjustments cautiously in order to preserve regulatory transparency and certainty to the greatest extent possible.

In order to avoid the possibility of overcompensation, it is advisable to begin with small financial incentives and adjust these gradually upward over time if needed. In some cases, a small financial incentive may be all that is needed in order to induce the utility to achieve the desired result, thus preserving the majority of benefits for ratepayers.

An incremental approach also allows utilities and regulators to gain experience with an incentive mechanism and manage any unforeseen consequences of the incentive without large impacts on ratepayers. As parties gain more confidence that the performance incentive mechanism does not suffer from any major flaws, the amount of compensation can be increased if needed.

5.2. Rewards and Penalties in the Context of New Regulatory Models

Several recent proposals for new regulatory models emphasize the goal of rewarding utilities for performance and desired outcomes. For example, a utility-stakeholder collaborative group in Minnesota writes:

> As its name suggests, a performance-based approach would tie a portion of a utility's revenue to achieving an agreed-upon set of performance metrics (e.g., measuring such things as energy efficiency, customer service, environmental sustainability, affordability, and competitiveness) so that utilities have a natural financial incentive to produce the outcomes customers want (e21 Initiative 2014, 3).

The RIIO model that is being developed and applied in the UK includes financial incentives that are roughly equal to 5 percent of utility revenues (see Appendix A). This is considered to be a relatively large portion of utility revenues to dedicate to financial incentives, and we are not aware of any states or countries that apply larger financial incentives.

Whether a set of performance incentives will result in "a natural financial incentive to produce the outcomes customers want" will clearly depend upon many factors, such as the type and scope of the outcomes targeted, the performance metrics, the targets chosen, the amount and type of financial incentives, and more. One of the key factors likely to determine how well the combination of incentives will lead to desired outcomes is the amount of money that is at stake. As described in Chapter 2, utilities already have many different financial incentives, some of which are aligned with customer interests, some of which are not. These existing financial incentives are very influential and exist in every regulatory context.

In thinking about new regulatory models, one key question that regulators should ask is: Will the set of new performance incentives be sufficient to modify, or at least balance against, the financial incentives of the existing regulatory model? Regulators should compare the magnitude of the proposed performance incentives with the magnitude of existing financial incentives. If new regulatory models are to result in a fundamental shift of incentives away from capital investments and toward performance outcomes, then the magnitude of the financial rewards and penalties will need to be significantly larger than the amounts used to date in the United States, and may need to be larger than under the RIIO model used in the UK, discussed below.

In addition, new regulatory models will need to reduce the incentive that utilities currently have to increase their rate base. This could be achieved by reducing, or eliminating, the amount of profit that a utility earns from rate base, and replacing that amount of profit with revenues from performance incentives.[23] Ultimately, the combined impact of modified equity recovery plus financial incentives should meet the standard criterion of allowing the utility to recover prudently incurred costs plus an opportunity to earn a reasonable return on equity. In this case the opportunity to earn a reasonable return on equity would be based primarily, or entirely, on utility performance relative to the performance incentives.

When designing new regulatory approaches for utilities to recover revenues, regulators must also be cognizant of the implications for utility financial positions. First, utilities must be able to maintain a reasonable financial position for a reasonable level of performance. Second, as noted above, managers and analysts need to be able to assess the risk associated with new regulatory mechanisms, and shifting the sources of revenues could easily change the risk profile of a utility's financial position.

It may also be important to consider the timing of revenue recovery. If the recovery of equity costs is partially replaced by the recovery of performance incentives, then the timing should be properly aligned. Currently utilities are allowed to recover equity and debt costs over the full book life of a capital asset. If the financial incentives are recovered over a shorter time period, then there might be a misalignment of when customers experience the benefit and when they are charged for it. On the other hand, performance incentives typically work best when the rewards and penalties are applied relatively close in time to the performance outcomes themselves.

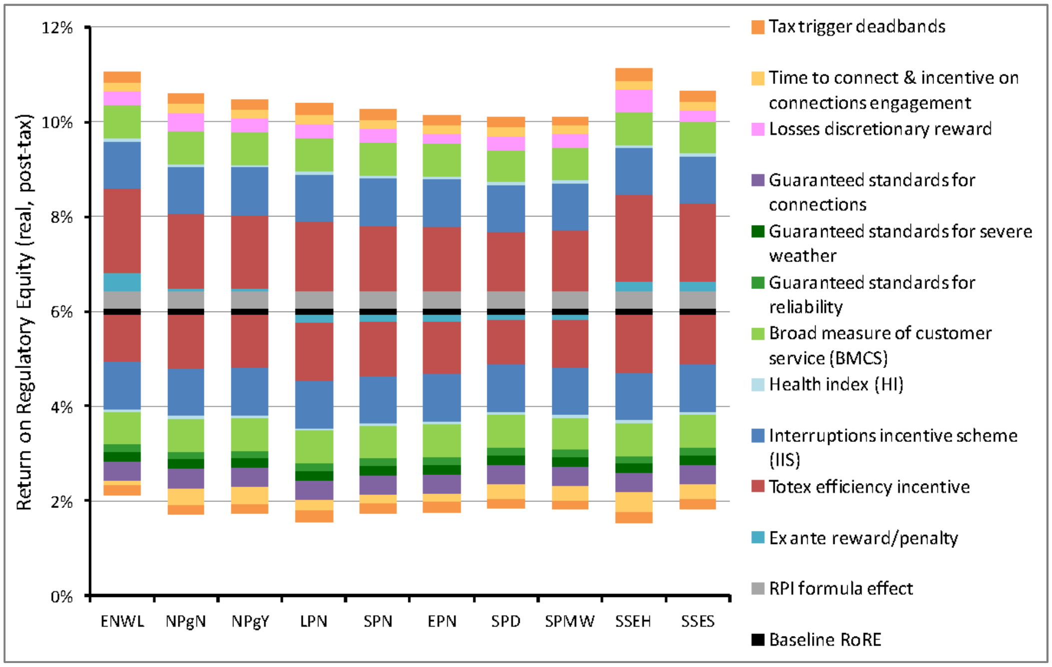
An Example: the RIIO Model

The UK's RIIO model bases a large amount of a utility's earnings on its performance. As detailed in Appendix A, potential rewards and penalties associated with environmental, customer satisfaction, social obligations, and connections performance incentive mechanisms equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

[23] Under RIIO, capital expenditures and operating expenditures are combined into one category: "total expenditures," or "totex." The utility then earns a return on a pre-determined portion of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

These performance incentive mechanisms are part of a revenue cap plan that provides for annual revenue increases at the rate of inflation and allows utilities to retain a large portion of any cost savings they achieve. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 8. Plausible ROE Range for UK Distribution Utilities



Source: Ofgem 2014b, page 46

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been "appropriately calibrated" (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

6. Implementation

6.1. Questions to Help Inform Regulatory Action

Regulators may wish to ask themselves, as well as relevant stakeholders, several questions that would help inform their decisions on whether and how to proceed with performance metrics and incentives. For example:

1. **How well does the existing regulatory framework support utility performance?**

   Are the utilities already achieving standard regulatory goals, such as providing low-cost, safe, reliable service? Are there specific areas of performance where utility performance has been questionable, or where customers have raised complaints? What activities or investments are currently the key profit centers for the utilities?

2. **How well does the existing regulatory framework support state energy goals?**

   What are the priority state energy policy goals, and how well do the utilities achieve them? These may include a variety of goals related to costs, reliability, clean energy resources, grid modernization, customer protections and more. Regulators should recognize that policy goals may evolve, and may require different incentives and regulatory models over time.

3. **What are the policy options available to improve utility performance?**

   As described in Chapter 2, there are many regulatory policies that will provide utility incentives and influence utility performance. Regulators may wish to modify or implement any of these other policy options in concert with, or in lieu of, performance metrics and incentives.

4. **Is the industry, market, or regulatory context expected to change?**

   If change is expected to occur, utilities may benefit from additional regulatory guidance regarding the preferred response, or may require additional incentives that were not necessary previously. There may also be emerging policy goals that the commission wishes to emphasize.

5. **Does the commission prefer to oversee investments, or to guide outcomes?**

   Traditional regulation typically allows regulators to oversee the utility investments and activities that are intended to achieve desired outcomes (e.g., during a rate case). In contrast, performance metrics and incentives allow regulators to provide more guidance on the desired outcomes, and less guidance on the means to achieve them.

6. **Does the commission wish to specify the outcomes in advance?**

   Traditional regulation typically allows regulators to oversee major capital investments and review expenses after the costs are incurred (typically during a subsequent rate case). As a result, there is little regulatory guidance provided before investments are made, at a time when alternative actions or investments can be considered. Integrated resource planning, where it is practiced, provides an exception to the common practice that regulation only takes place after the fact, after the money has been invested or spent. Performance metrics and incentives, on the other hand, provide greater regulatory guidance up front, and are therefore more likely to influence the outcomes.

The answers to these questions will help regulators determine what level of performance regulation is appropriate for their jurisdiction, and what type of performance metrics and incentives to implement.

6.2. Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally, to allow for each step to inform the subsequent step, or they can be implemented several steps at a time, or all at once.

1. Articulate goals**.** The first step is to identify and articulate all the energy policy goals that are applicable to utility regulation, whether the goals are current or anticipated.
2. Assess current incentives**.** Next it is critical to assess and understand the financial incentives, including those in place within company management and provided by utility interactions with investor analysts, which are created by the current or anticipated regulatory, management, and financial context. Performance incentives should then be designed to modify, balance or supplement these existing incentives. (See Chapter 2.)
3. Identify performance areas that warrant performance metrics**.** These performance areas may include traditional performance areas or new and emerging performance areas, depending on the needs of the particular jurisdiction. (See Chapter 3.)
4. Establish performance metric reporting requirements**.** Use performance metrics to monitor those areas identified in Step 3. Review the results over time to identify any performance areas that may require targets. (See Chapter 3.)
5. Establish performance targets, as needed**.** Establish targets to provide utilities with a clear message regarding the level of performance expected by regulators. Review the results over time to determine whether any performance areas warrant rewards or penalties. (See Chapter 4.)
6. Establish penalties and rewards, as needed. Establish reward or penalties to provide a direct financial incentive for maintaining or improving performance. (See Chapter 5.)
7. Evaluate, improve, repeat. Creating effective performance incentive mechanisms is an iterative process. The effectiveness of the mechanisms should be monitored closely and evaluated to determine which aspects are working well, and which are not. Targets, financial incentives, and other components of the mechanisms may need to undergo several adjustments before they achieve their full potential. (See Section 6.4)

6.3. Pitfalls to Avoid

No performance incentive mechanisms can be said to be perfectly designed, but those that work well succeed in providing greater benefits than costs to all parties. Unfortunately, there are also many examples of performance incentive mechanisms that have not succeeded, for a variety of reasons. Below we address some common pitfalls that regulators should endeavor to avoid when designing performance incentive mechanisms.

Disproportionate Rewards (or Penalties)

Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.

It is critical that regulators avoid the pitfall of over-rewarding utilities for performance. When utility rewards exceed the benefits to customers, particularly when they are first implemented, the entire concept of incentive mechanisms is undermined. Higher-than-expected rewards can also result in substantial backlash against performance incentive mechanisms that might have otherwise worked well.

Potential Solutions

One way to avoid this pitfall is for regulators to adopt an incremental approach: begin with small rewards and monitor and adjust over time. Another option is to establish caps on rewards (and penalties), to ensure that they stay within reasonable bounds.

Avoided Costs and Disproportionate Rewards

To encourage improved nuclear power plant performance, California implemented incentive payments for electricity produced by several of its nuclear reactors. In 1988, a settlement established the payment rate for electricity produced by Diablo Canyon, based on then-current avoided costs of fossil generation. This rate was to remain fixed, escalated only for inflation. By the mid-1990s, Diablo Canyon was earning more than $0.12/kWh, while Western Market wholesale power prices were approximately $0.03/kWh.

Later, a similar performance incentive mechanism was established for Palo Verde Nuclear Generating Station, but in this case the payment was set at the avoided cost of replacement power. Unfortunately, by the summer of 2000 the California energy crisis was in full swing, and the cost of replacement power had increased more than ten-fold. Again, the volatility of the markets had resulted in utility rewards much higher than intended. Both of these performance incentive mechanisms were subsequently modified, and further details can be found in Appendix A.

Another tool that can help prevent excessive compensation to utilities for some PIMs is shared savings. For example, when a utility implements a cost-saving measure, shared savings mechanisms pass on a portion of utility profits to ratepayers. Again, it is advisable to begin with a shared-savings mechanism that passes most profits to ratepayers, and reduce this proportion over time if needed in order to provide the utility with greater incentives.[24]

Unintended Consequences

Perhaps the most challenging aspect of designing performance incentive mechanisms is anticipating and avoiding unintended consequences. A common effect of establishing an incentive for one aspect of utility performance is to shift management's attention to the areas with incentives, to the detriment of areas that do not have incentives.

Unintended effects can also result from failing to recognize the linkages between various aspects of the utility's system. For example, providing an incentive for achieving high capacity factors at certain utility power plants could create several perverse incentives, such as encouraging the utility to: (1) increase sales, (2) operate units out of merit order, (3) engage in otherwise uneconomic off-system sales, or (4) defer needed maintenance outages.

<u>Potential Solutions</u>

Avoiding unintended consequences requires significant attention to the myriad incentives utilities face and the ways in which the performance target may influence other aspects of the utility's system. Strategies to minimize negative impacts include:

- Implement a diverse, balanced set of incentives to avoid concentrating management attention on only one area.
- Focus on performance areas that are relatively isolated from others, where possible. Energy efficiency is a good example of an area that may have relatively little impact on other aspects of utility performance.
- Explicitly assess up front how performance standards might influence other performance areas that do not have standards. Solicit input from multiple stakeholders and learn from experiences in other states.
- Allow for performance incentives to evolve over time to correct for unintended consequences.

Regulatory Burden

[24] Shared-savings mechanisms can also be structured to give a greater proportion of early savings to one of the parties (either shareholders or ratepayers), and a smaller proportion of later savings to that same party. A regressive sharing mechanism gives more of the early savings to shareholders, but less of the later savings. A progressive savings mechanism works in reverse by providing more of the early savings to ratepayers. An advantage of the progressive shared savings mechanisms is that it protects ratepayers against uncertainty, since if the performance target is miscalculated and set too low, ratepayers still retain a large portion of the savings. Progressive sharing mechanisms also create a stronger incentive for the utility to achieve high levels of savings. However, if the target is set where it is already difficult for the utility to meet and already delivers significant value to ratepayers, a regressive mechanism may be appropriate for equity reasons. For more discussion, see Testimony of William B. Marcus, PBR Economic Issues, JBS Energy, in California PUC Docket A. 98-01-014, July 3, 1998.

If performance incentive mechanisms are not designed well they can be too costly, too time-consuming, or too much of a distraction, for the utility, the regulators, and other stakeholders. Data reporting and verification can be resource intensive. Determining appropriate targets can be time-consuming and contentious, and disputes over penalties can be expected, particularly when large sums of money are at stake. These activities can divert limited resources away from more important issues, becoming an unnecessary distraction.

Reducing Regulatory Burden in New York

In 2012, the New York Public Service Commission issued an order that abolished the penalty portion of energy efficiency incentives. The Commission's experience was that the threat of penalties "created an adversarial approach to setting targets and budgets, undue aversion to risk, and short-term allocation of resources that may not serve the long-term interests of a balanced program." In addition, consideration of mitigating circumstances presented a substantial drain on staff and utility resources that could have been better spent on administering programs. See NY PSC 2012, 5-6.

Potential Solutions

To avoid unnecessary regulatory burden, regulators should endeavor to streamline performance incentive mechanisms by using existing data and protocols where possible, and relying on simple mechanism designs. If a specific PIM is becoming a distraction, it may be because too much money is at stake. Ensuring that the reward or penalty is commensurate with the importance of the policy goal will help to ensure limited resources are appropriately allocated.

Uncertainty

Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to incentives create uncertainty for the utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.

Potential Solutions

A critical step in reducing uncertainty is to carefully specify metric and target definitions, soliciting utility and stakeholder input where possible. If historical data are available, it can be instructive to use such data to provide examples of how the performance data will be assessed and rewarded or penalized in the future. As discussed in the case study in Chapter 3, such an approach may have helped Nevada utilities and stakeholders avoid much of the litigation and controversy regarding whether a certain type of facility would be designated as a "critical facility" eligible for enhanced return on equity.

The speed with which performance metrics and incentives are reported and applied can help reduce uncertainty. Information regarding the achievement of targets and the magnitude of incentives should be provided as quickly as possible, to minimize uncertainty and allow for mid-course corrections as soon as possible.

Regulatory certainty is equally important for ensuring that long-term utility investments are made efficiently, and incentives are not diluted. To this end, regulators should adjust targets and financial consequences only cautiously and gradually so as to reduce uncertainty and encourage utilities to make investments with long-term benefits.

Gaming and Manipulation

Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results. “Gaming” refers to a utility taking some form of shortcut in achieving a target so that the target is reached, but not in a way that was intended. For example, if a performance incentive were set that rewarded a utility for increasing a power plant’s capacity factor above a certain threshold, the utility might understandably respond by increasing its off-system sales from that power plant, even at an economic loss. Thus the utility would be able to meet or exceed the target capacity factor, but ratepayers would be worse off.

Manipulation of the results refers to the deliberate alteration or obscuring of unfavorable performance data, whether through use of dubious analysis methods, improper data collection techniques, or direct alteration of data. An example of this occurring in California is provided in Appendix A, as well as in a call-out box in Chapter 3.

<u>Potential Solutions</u>

The ability of utilities to game an incentive typically points to the need to refine how a metric is defined. In the example above, the metric could be redefined to exclude energy sold at a loss or energy from a unit that is operated out of merit order. This pitfall can be quickly remedied by ensuring that regulators carefully monitor how well performance incentive mechanisms are achieving their intended results, and step in quickly to make necessary adjustments, particularly where an incentive is clearly being gamed. In addition, the potential for gaming makes it all the more important that financial rewards and penalties are set conservatively in the beginning, and only increased once regulators and utilities gain experience with the performance incentive mechanism.

Manipulation can be more difficult to detect, particularly when data are collected and analyzed by the utility. To reduce the risk of manipulation, verification methods should be adopted and independent third parties used to collect, analyze, and verify data where practical. Complex data analysis techniques that are difficult to audit should generally be avoided, as they reduce transparency.

6.4. Summary of Key Performance Incentive Mechanism Design Principles

The table below provides a recap of the key principles for performance incentive mechanism design.

Table 16. Key Principles and Recommendations

Regulatory Contexts **(Chapter 2)**	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics **(Chapter 3)**	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets **(Chapter 4)**	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties **(Chapter 5)**	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

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Appendix A – Detailed Case Studies

California

California has a long history of employing various performance incentive mechanisms, and much can be learned from the successes and failures of these experiments. Here we discuss a few of the performance incentive mechanisms that have been employed in California, focusing particularly on the lessons that have been learned along the way.

It is often easier to point out instances of when mechanisms have gone awry than where mechanisms have functioned well, due to the amount of attention garnered by the former. For this reason, much of the discussion below highlights the challenges that have been encountered along the way and strategies for avoiding similar difficulties in the future. This should not be taken to imply that performance incentive mechanisms always or often encounter these problems. Indeed, California's willingness to continue to experiment with performance incentive mechanisms indicates that regulators continue to believe that they are a useful regulatory tool.

Nuclear Power Plant Performance

<u>Diablo Canyon Nuclear Incentives</u>

The 1980s were characterized by numerous nuclear power plant cost overruns and generally low industry-wide nuclear plant capacity factors. Pacific Gas and Electric's (PG&E's) $5.5 billion Diablo Canyon power plant was one example of a power plant that exceeded its estimated construction budget by several billion dollars.

In 1988, the California Public Utilities Commission (CPUC) authorized a settlement regarding Diablo Canyon that was intended to protect ratepayers from the significant cost overruns of the plant, while encouraging the plant to operate efficiently. Instead of allowing PG&E to recover all of the costs of the plant automatically, the settlement based a large portion of the cost recovery on the amount of electricity that would be generated by Diablo Canyon. Energy from the plant was to be paid a set price per kilowatt-hour, and the utility would only recover all of its costs if the plant operated at a high capacity factor. Further, the utility and its shareholders assumed responsibility for all repairs and additional investments at Diablo Canyon (CPUC 1988).

The settlement shielded ratepayers from the risk that the plant would perform poorly or incur significant additional costs. However, there were three aspects of the performance incentive mechanism in the settlement that would ultimately work to the disadvantage of ratepayers:

- First, the target capacity factor above which PG&E would earn a profit was set based on industry averages, rather than based on the much higher-than-average capacity factor of Diablo Canyon at the time of the settlement.[25]
- Second, the financial reward to PG&E for generating electricity from the plant was set at a fixed price (escalated for inflation), rather than being flexible to account for changing market conditions. As a result, ratepayers continued to pay a set price per kWh of electricity from Diablo Canyon even when it would have been more economical to use energy from other sources (such as oil or gas) (CPUC 1988). Although the price set for electricity from Diablo Canyon appeared reasonable at the time, in later years Diablo Canyon power became significantly more expensive than power sold on the West Coast wholesale market.[26]
- The performance incentive mechanism contained no shared savings component or other safety valve that would have reduced the consequences of getting either of the above two elements wrong.

PG&E successfully operated the Diablo Canyon power plant, achieving capacity factors much higher than the industry average at the time of the settlement agreement, and producing profits for shareholders. In this way, the incentive mechanism can be said to have been successful in providing an incentive for the utility to operate the nuclear power plant efficiently, but the choice of a target capacity factor and locking in the power plant's energy price did not generate the intended benefits for ratepayers. The performance incentive mechanism ultimately proved to be unstable and was modified in later years and finally eliminated in 2002 through Decision 02-04-016.

A more tenable performance incentive mechanism might have also have (a) included a shared savings component, whereby ratepayers would receive a portion of any profits generated, or (b) tied the price paid for Diablo Canyon power to the avoided cost of power from fossil generators. These components would have distributed the risk more equitably between ratepayers and the utility.

<u>Palo Verde Nuclear Incentives</u>

In the 1990s, California adopted additional performance incentive mechanisms for other nuclear power plants, including the Palo Verde Nuclear Generating Station. The terms of this incentive mechanism were modified from those of Diablo Canyon: the utility would receive a reward for generation above a capacity factor of 80 percent, and the reward would be calculated based on the difference between Palo Verde's incremental variable cost and the cost of replacement power. In addition, the performance incentive mechanism initially included a provision for sharing of benefits between shareholders and ratepayers in later years, although this provision was eliminated before it took effect (CPUC 2001).

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[25] The capacity factor from the date of commercial operation through June 30, 1988 was 67.7% for Unit 1 and 76.7% for Unit 2, as compared to an industry average of 58% for similar large nuclear power plants (CPUC 1988, 112, 114).

[26] In 1994, Diablo Canyon was earning more than 12 cents/kWh, while Western Market wholesale power prices were approximately 3 cents/kWh (Smeloff and Asmus 1997, 82).

Although this performance incentive mechanism incorporated greater protections for ratepayers than the PIM for Diablo Canyon, it ultimately also proved to be unstable. When the PIM was initially developed, the cost of replacement power was expected to be in the range of $0.03 to $0.05 per kilowatt-hour, but by summer 2000, these costs had escalated to more than ten times higher. For this reason, stakeholders lobbied for a limit on the incentive payments and the commission instituted a cap of $0.05 per kilowatt-hour (CPUC 2001).

The Palo Verde incentive mechanism was initially designed to expire at the end of 2001, at which point Palo Verde would be returned to cost-of-service ratemaking. Upon petition by SCE, the incentive mechanism was continued until SCE's next general rate case, effective May 22, 2003 (Southern California Edison 2006a).

Lessons Learned

California's experience with nuclear power incentives highlight just how difficult it can be to set a reasonable target and incentive payment. These difficulties can be mitigated by using shared savings mechanisms or instituting safety valves—such as Palo Verde's cap on the incentive payment.

Gaming and Manipulation of Performance Incentive Mechanisms

In 1990, the CPUC began an investigation into incentive-based ratemaking for gas utilities (R90-02-008 and I90-08-006), finding that a PBR plan with indexing could "provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity" (CPUC 1991, 1). Beginning in 1993, the CPUC approved gas procurement mechanisms for the gas utilities that replaced after-the-fact reviews of gas procurement with market-based gas price benchmarks.

Soon, the CPUC began to also approve PBR mechanisms for electric utilities. PBR was introduced as an alternative to cost-of-service regulation, which the Commission felt had become "too complex to allow us to regulate utilities effectively" (CPUC 2008, 2). The Commission hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3).

A PBR plan was adopted for Southern California Edison (SCE) though Decision (D.) 95-12-063 and modified by D.96-09-092. Three categories of service incentives were created: reliability, customer satisfaction, and health and safety.

SCE's Customer Satisfaction Incentive Mechanism terminated at the end of 2003, while some form of Employee Health & Safety Incentive Mechanism continued through 2005 (Southern California Edison 2006b). From 1997 to 2000, SCE received $48 million in rewards under the customer satisfaction and health and safety incentive mechanisms. Subsequently, SCE requested $20 million in customer satisfaction rewards for 2001 to 2003 and $15 million in health and safety rewards for 2001 and 2002. However, in a 2008 decision, the CPUC ordered SCE to refund these rewards and forgo the additional rewards requested, as well as pay a fine totaling $30 million. The problems leading to this decision are briefly described below, followed by remarks regarding how such results might be avoided in the future.

Customer Survey Problems

Under the Customer Satisfaction Incentive Mechanism, customer satisfaction was measured through the use of third-party administered surveys with rewards and penalties in four areas: field services, local business offices, telephone centers, and service planning. Each area received a score of 1 to 5+, where 1 was low. Scores were then averaged across the four service areas to obtain the overall average score (CPUC 2008).

The original target for the overall customer satisfaction score was set to 64% of scores being 5 or 5+, with a deadband of plus or minus 3%. Beyond the deadband, the utility received a reward or penalty of $2 million for each percentage point change in the average result, up to a maximum of $10 million per year. In addition, if any one area received a score of less than 56%, a penalty would be assessed. In D.02-04-055, the Commission increased the customer satisfaction target from 64% to 69%, based on the average of the then most recent nine years of survey results (CPUC 2008).

The problems with the customer survey began with the selection of customers for the survey pool. This exercise was left to the meter readers themselves, who were supposed to push a button on a handheld device they carried every time they had a meaningful interaction with a customer (whether it was positive, neutral, or negative). However, there was no practical means of ensuring that meter readers actually did record interactions that were both positive and negative. In addition, SCE employees sometimes falsified the contact information to screen out customer interactions that might result in negative customer satisfaction surveys (CPUC 2008).

Further, some SCE employees attempted to skew survey results favorably by requesting that customers give them a good score when surveyed, giving customers collateral materials (such as golf balls and ball point pens), or telling customers that a survey score of less than 5 would represent a failing score that might lead to disciplinary action against the utility employee (CPUC 2008).

Thus despite using a third party to administer the customer satisfaction survey, the performance incentive mechanism failed because the data collection process was exposed to data manipulation and gaming by utility employees. The issue only came to light when a whistle blower wrote an anonymous letter to an SCE senior vice president. Even then, the initial review of the allegations concluded that any survey problems were inadvertent. After another anonymous letter was received with more serious allegations (including that SCE managers and high-level directors were aware of the conduct), an independent investigation was launched that began uncovering the misconduct. Ultimately, the California Public Utilities Commission found that from 1997 through 2003, SCE “manipulated and skewed survey results, artificially inflated survey outcomes, and received PBR rewards” (CPUC 2008, 16).

Underreporting Employee Health and Safety Incidents

Employee health and safety was measured by the number of first aid incidents and lost time incidents, based on historical averages as reported to OSHA. Based on that data, the benchmark was set at 13.0 injuries and illnesses per 200,000 hours worked with a dead band of +/-0.3. In 2002, the target was reduced to 9.8 injuries and illnesses based on the most recent seven years of data, and in 2003 it was further reduced to 8.6 injuries and illnesses. Results above or below the dead band would result in rewards or penalties (CPUC 2008). Unfortunately, from the beginning this performance incentive mechanism was deeply flawed.

As with the customer surveys, the first problem with the Employee Health and Safety Incentive Mechanism was that data were not appropriately collected – both in the establishment of the performance target and for compliance reporting. To begin with, the utility did not establish a system to track all first aid incidents, leading to underreporting of the data used to establish the performance target, as well as the compliance data. Further, SCE maintained different standards for internal safety performance measures than for compliance with the performance incentive mechanism. The unsurprising result was that only a small fraction of first aid incidents were reported.

Second, the existence of the incentive mechanism actually discouraged employees from reporting injuries. The Commission found that particularly “when safety incentives are group-based (as they are in some business units), injured employees may want to avoid reporting their injuries and jeopardizing safety incentive compensation not just for themselves, but also for the rest of their group” (CPUC 2008, 60)

In addition, some supervisors participated in or encouraged under-reporting of data. “Among the methods used to disguise injuries and avoid internal reporting are: employee self-treatment; treatment by personal physicians rather than the company doctor; timecard coding of lost time as sick days or vacation; etc.” (CPUC 2008, 60).

Lessons Learned

In both the customer satisfaction and health and safety incentive mechanisms, data collection was seriously flawed. These experiences highlight the need to validate data frequently and to employ independent third parties for data collection where possible. However, the disincentive for employees to self-report health and safety data may be too great to overcome. Because of the great importance of maintaining a safe work environment, some jurisdictions have elected to eliminate performance incentives for health and safety in order to avoid creating perverse incentives. This does not mean that such data cannot or should not be tracked, but financial rewards or penalties should be carefully considered.

Recent Experience with Performance Incentives in California

In the early 2000s, California abandoned performance-based ratemaking and returned to “a transparent regime of cost-based ratemaking” (CPUC 2004, 288). However, the Commission elected to continue to use performance incentive mechanisms, as

> “they provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms.… They can be carefully adapted to the cost-of-service regime and enhance our ability to regulate in the public interest, providing both financial incentives to guide utility activities and an early warning of longer-term trends

> that we can use to guide more intrusive regulatory interventions such as complaints and investigations. They represent a calibration, not a contradiction, of our cost-of-service principles" (CPUC 2004, 289).

Although the customer service and health and safety performance incentive mechanisms as described above have been discontinued, the California Public Utilities Commission has continued to experiment with performance incentive mechanisms where warranted. Under a cost-of-service regime, however, the CPUC requires that the need for such incentives be fully justified, stating:

> "We will consider whether the proposed performance incentives are necessary for achieving one or more of our regulatory objectives and are likely to be cost-effective; we do not believe that performance incentives should be adopted solely on the basis of their mere consistency with a particular objective. Since rates set through our conventional approach to ratemaking are intended to provide the funding required to meet the regulatory objectives of safe and reliable service, we must ask why the utility needs the possibility of additional ratepayer funding, or threat of reduced funding, to get the utility to do what it is already funded and expected to do. The burden is on the proponents of performance incentives to prove they are necessary, cost-effective, and otherwise reasonable" (CPUC 2004, 290).

Renewable Energy Procurement Costs

California has long had a Renewable Portfolio Standard (RPS), but certain provisions in the enforcement rules caused CPUC become concerned that construction delays and contract failures could jeopardize PG&E's compliance with the RPS (CPUC 2010). The RPS enforcement rules contained loopholes to deal with the cumbersome, short annual compliance period that was required by legislation, such as allowing retail sellers to incur a certain percentage of their annual procurement obligation as a deficit without explanation. As another example, the rules allowed "earmarking" of future contracted deliveries for the current compliance period, even if deliveries were not anticipated to commence in the current compliance period (CPUC 2014a).

In February 2009, PG&E filed a proposal—with no performance incentive component—to implement and recover costs of a photovoltaic (PV) program. In response to recommendations by other parties, the CPUC approved the program but adopted a price cap of $246 per MWh and a cost savings incentive mechanism "to better align PG&E's financial interests with those of ratepayers" (CPUC 2010, 31).

The program target called for installing 50 MW of utility-owned PV capacity per year for five years (for a total of 250 MW of utility owned generation). PG&E could also enter into power purchase agreements (PPAs) for up to 250 MW of PV. Under the cost savings incentive mechanism, PG&E shareholders were permitted to retain 10% of cost savings if actual average capital costs over the life of the PV Program fell below $3,920 per kW, representing PG&E's capital cost estimate with no contingency amount. Ratepayers were entitled to retain 90% of the cost savings below $3,920 per kW. Although the CPUC did not specify a penalty, capital costs above $4,312 per kW were subject to a reasonableness review.

Notably, PG&E opposed the cost cap and cost savings incentive mechanism, largely on the grounds that these elements exposed PG&E to uneven risks and rewards (CPUC 2010, 55–56).

In December 2012, PG&E requested to terminate its PV Program after the second PV PPA solicitation and to procure the remaining capacity using the Renewable Auction Mechanism (RAM) process adopted by the CPUC in D.10-12-048 instead. The CPUC rejected the request on procedural grounds. In February 2014, PG&E resubmitted its request, claiming that terminating the PV Program and using the RAM process to procure the remaining capacity would create significant administrative efficiencies, would reduce customer costs, and was appropriate given that the PV sector had significantly transformed since the PV Program was approved in 2010 (PG&E 2014). In November 2014, the CPUC granted PG&E's request to close the PV Program, noting that the CPUC's goals in establishing the program were substantially achieved and the availability of other procurement tools for smaller scale RPS-eligible products, making the PV program duplicative and administratively burdensome (CPUC 2014b, 14).

Lessons Learned

The experience with the PV Program cost savings incentive mechanism suggests that asymmetrical risk and reward mechanisms are likely to garner opposition by utilities. In this case, PG&E shareholders were permitted to retain only 10% of the cost savings below its capital cost estimate excluding contingency, and costs above the cost cap would be subject to regulatory review. On the other hand, ratepayers were entitled to retain 90% of the cost savings below $3920 per kW, and they were protected from the downside by a cost cap provision.

Another lesson from this experience involves consideration of administrative burden and redundancy. The potential rewards for the company were apparently not enough to outweigh the administrative burden of maintaining the PV Program. Given that the RAM process had matured since the inception of the PV Program, the latter became redundant.

The UK RIIO Model

When the British energy distribution and transmission utilities were privatized in 1990, a performance-based regulatory framework was adopted with a price control mechanism to regulate the utilities. This form of PBR was referred to as "RPI-X," as it allowed revenues to grow at the rate of the retail price index (RPI), less an X-factor which was designed to capture improvements in productivity, rewards and penalties, or other elements. The term of each PBR period was set at five years in order to incentivize efficiency improvements and cost reductions (the savings from which the utilities would retain until the end of the price control period). In order to prevent service quality degradation, the RPI-X plans also specified certain outputs that the utilities were required to deliver.

Over the past twenty-five years, this performance regulation framework has evolved to adapt to changing policy priorities and industry challenges. In 2008, the British Office of Gas and Electricity Markets ("Ofgem"), launched a fundamental review of the regulatory framework. Out of this review and stakeholder discussion was borne a revised form of PBR, one more comprehensive and performance-based than the RPI-X system. This new framework is referred to as "RIIO," an abbreviation for Revenue = Incentives + Innovation + Outputs.

RIIO seeks to improve upon the RPI-X model and respond to concerns that:

- The RPI-X framework focused the utilities on achieving cost savings, but not on delivering other outputs, such as improved quality of service.
- The five-year duration of the RPI-X price control period was not sufficient to encourage companies to focus on long-term trade-offs and effects of investments, innovation, and service quality.
- The RPI-X framework was not flexible enough to respond and adapt to step-changes in technology. Additional incentives were felt to be needed to stimulate innovation and adequately respond to sector-wide need to transition to a low-carbon energy industry (Jenkins 2011).

RIIO was designed to address these concerns by (a) shifting the focus from cost control to delivery of outputs through the use of performance incentives, (b) increasing the price control period to eight years, (c) increasing the focus on innovation through financial incentives and an innovative projects competition, and (d) increasing the emphasis on competition where possible. It is expected that these adjustments will encourage utilities to innovate to deliver cost savings and value for customers, as the utilities will retain most of the efficiency savings they generate for a longer period and they have the potential to earn rewards for over-delivering in certain performance areas.

Base revenues under RIIO are determined through utility business plans. These plans must be well-justified and designed to establish a long-term corporate strategy for delivering "value for money" to customers. In developing their business plans, the utilities are required to assess alternative options for delivering outputs, evaluate the long-term costs and benefits for each alternative, and incorporate stakeholder input. Once approved, the business plans form the basis for revenue adjustments over the next eight years, with annual true-ups to account for differences in actual versus projected sales. A sharing mechanism allows utilities and customers to share any savings or overages relative to the budget, with the majority of shared savings generally accruing to the utility (ENA 2014; Ofgem 2013a).[27]

In addition to the base revenues established through utility business plans, utilities may be rewarded or penalized based on their performance in delivering specific outputs. As discussed in detail in the following sections, these rewards and penalties can have a relatively large impact on each utility's realized return on equity, with impacts of up to approximately +/- 300 basis points (Ofgem 2014b).[28]

The electric distribution network price control period will begin on April 1, 2015 and last until March 31, 2023. At the time of writing, the electric utilities had submitted their business plans to Ofgem for review, and Ofgem had approved (with modification) all of the plans. One utility's plan was "fast tracked" and accepted in full, due to it being of sufficiently high standard. The fast-tracked utility also received a reward equal to 2.5 percent of "totex" (capital expenditures + operating expenditures). The other five utilities' plans were approved, but with allowed revenues of approximately 5 percent less than requested in their business plans (Ofgem 2014b).

RIIO Outputs

Outputs are a core element of the RIIO regulatory framework, falling in six categories:

1. Safe network services
2. Environmental impact
3. Customer satisfaction
4. Social obligations
5. Connections
6. Reliability and availability

Within each of these categories, "secondary deliverables" have been identified upon which utilities will be required to deliver. For example, one of the secondary deliverables under the environmental impact category is a utility's total CO_2 equivalent emissions.

A series of working groups was established in order to identify specific metrics and incentives for each of these deliverables. Ofgem also received input from the Consumer Challenge Group, a small group of

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[27] The percent of savings that the utility can retain under the "efficiency incentive" ranges from 45 percent to 70 percent, depending on whether the utility is fast-tracked or not, and the degree to which the utility's forecasts align with Ofgem's models. This sharing rate is set as part of the Informational Quality Incentive (Ofgem 2013a).

[28] The financial impacts of the performance incentive mechanisms associated with specific outputs are in addition to total expenditure efficiency incentives, informational quality incentives, and rewards associated with compiling a high-quality business plan. These other incentives could have an additional impact of more than 100 basis points in either direction. See Figure 10 for the total impact of these factors.

consumer experts that work to ensure consumers' interests are fully considered. Targets for many metrics are set by the Ofgem with input from stakeholders, while for some metrics (such as asset health), utilities propose the targets themselves in their business plans. All targets proposed by utilities must be justified in terms of costs and benefits to customers and informed by stakeholder engagement (Ofgem 2012a).

Not all outputs under RIIO have financial incentives. For example, the Reliability and Safety Working Group rejected the use of incentives (financial or reputational) for safety, as it was felt they could result in unwanted implications for incident reporting (as occurred in California, described in the previous section). Moreover, utilities are already required to comply with health and safety standards set by another governmental agency, and would be subject to enforcement action from that agency in the event of non-compliance (Ofgem 2012a).

Some categories of outputs have "reputational" incentives, where results are published and utility performance compared against other utilities, but no financial incentives are imposed. For example, under the Business Carbon Footprint metric, each utility submits an annual report of its total CO_2 equivalent emissions, as well as the actions it has taken to reduce emissions relative to their baseline. This allows utilities to share best practices and learn from one another, while also providing time to refine data collection and analysis techniques to provide more reliable data prior to administering rewards and penalties (Ofgem 2012a).

In addition, Ofgem is careful to ensure that in areas where competition exists (such as connection services) no incentive benefits are provided to utilities that are not also available to independent providers. The total package of incentives are intended to be clear and balanced in order to prevent perverse incentives, and to ensure that utilities that provide value for customers' money earn a relatively high rate of return, while utilities that fail to deliver value earn low returns (Ofgem 2012a).

The following subsections summarize the performance incentive mechanisms currently in use or under development for RIIO. Utilities must also report on several performance metrics (such as noise, sulfur emissions) that do not have corresponding financial or other incentives and are therefore not listed in the table below. For more information, see Ofgem 2013a and Ofgem 2013b.

<u>Environmental Impact</u>

Currently two performance incentive mechanisms are associated with the environment impact category: electricity losses and business carbon footprint. UK utilities are contractually obligated to reduce losses as much as practicable, and can be found in violation of their license agreement if they fail to do so. If utilities are particularly successful or innovative in reducing losses, they may qualify for a reward, which increases over the duration of the PBR period in order to incentivize implementation of long-term solutions.

The incentive under the business carbon footprint is unusual in that it is reputational only, due to Ofgem's determination that data are not sufficiently reliable to form the basis for financial rewards or penalties (Ofgem 2012a).[29] Under this mechanism, utilities' performance is reported annually and made public by Ofgem. All utilities' results are aggregated into one table to facilitate comparisons across utilities.

Table 17. RIIO Environmental Impact Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Electricity losses	Discretionary reward of up to £4 million in year 2, £10 million in year 4, and £14 million in year 6 for utilities that exceed the loss reduction commitments in their business plans.	Utilities report annually on loss reduction activities undertaken, improvements achieved, and actions planned for the following year. Performance will be measured according to multiple criteria, including the effectiveness of actions taken to reduce losses, engagement with stakeholders, innovative approaches to loss reductions, and sharing of best practices with other companies.
Business Carbon Footprint (BCF)	Reputational	Annual reporting requirement on CO_2 equivalent emissions, actions taken to reduce emissions over the past year and their effectiveness. All utilities' performance on this metric summarized in one table.

Source: Ofgem 2012 and Ofgem 2013

[29] A distribution utility's business carbon footprint is in part based on contractor emissions, which may not be sufficiently reliable.

Customer Satisfaction and Social Obligations

Three performance incentive mechanisms are in place to measure customer satisfaction and the degree to which utilities fulfill social obligations such as assistance to vulnerable customers. Two of these performance incentive mechanisms, complaints and stakeholder engagement, are asymmetrical. Complaints are associated with a penalty only, while stakeholder engagement can only result in a reward.

Table 18. RIIO Customer Satisfaction and Social Obligations Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Customer satisfaction survey	Reward or penalty up to 1% of annual base revenue	A survey is used to measure the satisfaction of customers who have required a new connection, have experienced an interruption to their supply, or have made a request for a service or job to be completed. Performance is measured based on the response to the question: "Overall how satisfied were you with the service that you received?" The target score will be set at the beginning of the period, and will be set at a level that "can be objectively assessed to represent a good level of performance."
Complaints	Penalty of up to 0.5% of annual base revenue. No reward.	Complaints and their weightings are measured based on: (a) percentage of complaints that are outstanding after one day (10% weighting); (b) percentage of complaints that are outstanding after 31 days (30% weighting); (c) percentage of complaints that are repeat complaints (50% weighting); and number of Energy Ombudsman decisions that go against the utility as a percentage of total complaints (10% weighting). An industry target is set.
Stakeholder engagement	Reward of up to 0.5% of annual base revenue. No penalty.	The regulator will develop a mechanism for assessing the utilities' use of data and customer insight to understand and identify effective solutions for vulnerable consumers, as well as their ability to integrate this into core business activities.

Source: Ofgem 2012 and Ofgem 2013

Connections

In addition to the customer satisfaction survey (which measures, in part, satisfaction with the utility's service in interconnecting new customers or distributed generation facilities), two performance incentives encourage the utilities to efficiently interconnect residential customers and respond to the needs of large customers (including distributed generation). These incentives are asymmetrical; a reward (but no penalty) can be earned for the time required to process small customer interconnections, while the incentive for large connections (including distributed generation) is penalty-only.

Table 19. RIIO Connections Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Time to Connect Incentive for Small Connections	Reward of up to 0.4% of annual base revenue. No penalty.	Measures the time taken from initial application received to the issue of a quotation and the time taken from quotation acceptance to connection completion. Target based on historical performance data, and target will become more stringent over the period.
Incentive on Connection Engagement (ICE) for Large Connections	Penalty of up to 0.9% of annual base revenue. No reward.	Each utility must submit evidence of how they have identified, engaged with, and responded to the needs of their customers. These submissions will be compared to a set of minimum requirements, which will likely to require each utility to demonstrate how they have engaged with a broad range of customers, established relevant performance indicators, and developed a forward-looking work plan of actions to improve performance (with associated delivery dates). Separate submissions will be required for different market segments, including distributed generation customers. A penalty will be assessed for failing to meet the minimum requirements for that market segment. The regulator will also continue to engage with stakeholders to identify key issues and gather feedback on utility performance.

Source: Ofgem 2012 and Ofgem 2013

Reliability and Availability

Several performance incentive mechanisms are in place to ensure reliability and availability. These performance incentives carry sizeable rewards and penalties, based largely on studies of customers' willingness to pay. The interruptions incentive scheme is most comparable to SAIDI and SAIFI rewards and penalties in the United States, but has separate components for unplanned versus planned outages. Because the utilities provide prior notice to customers regarding planned outages, they are less disruptive to customers. For this reason, planned outages carry a lesser financial reward or penalty as compared with unplanned outages (Ofgem 2012b; Ofgem 2013b).

The guaranteed standards of performance incentives reflect a 2010 law (SI No. 698, 2010.27) that requires utilities to make payments to customers whenever performance falls below a certain level. For example, the 2010 law requires a payment from the utility directly to affected customers who experience outages lasting more than 18 hours, or who experience four or more outages a year. RIIO maintains or strengthens these existing standards.

Finally, RIIO also penalizes or rewards utilities that under- or over-deliver on the health and load indices of their assets. Utilities target a certain level of output delivery in their business plans, which then form the basis for their allowed revenues in this area. (These performance levels must be justified through both cost-benefit analysis and stakeholder engagement.) Under-performance therefore results in both a penalty and a downward adjustment to future allowed revenues, while over-performance results in a reward and higher future allowed revenues (Ofgem 2012b; Ofgem 2013b).

Table 20. RIIO Reliability and Availability Performance Incentive Mechanisms

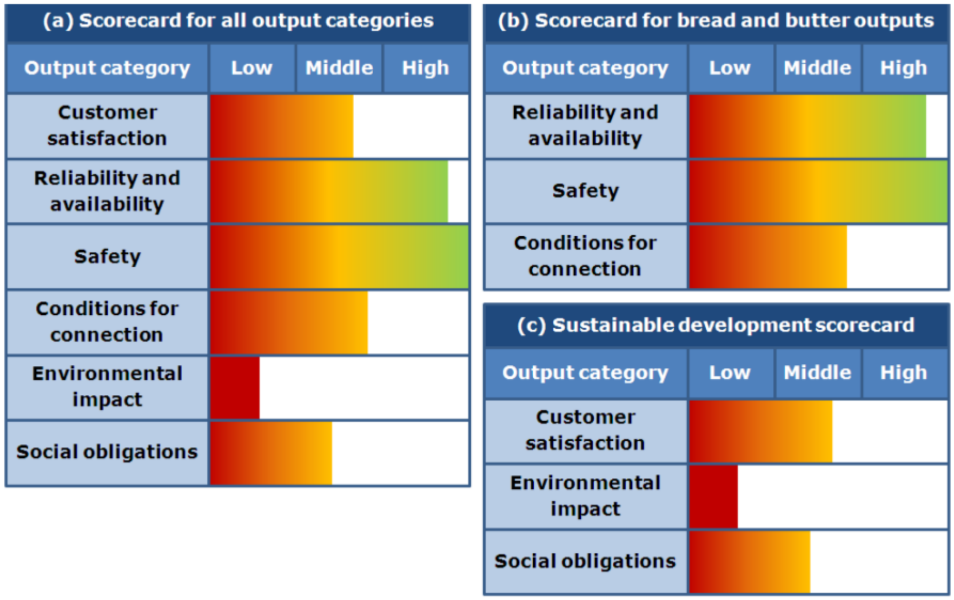
Deliverable	Penalty or Reward	Metric and Target Description
Interruptions Incentive Scheme	Penalty or reward of up to 250 basis points on rate of return per annum	Utilities are incentivized on the number and duration of network supply interruptions versus a target derived from benchmark industry performance. Planned and unplanned outages have separate targets, and planned outages are rewarded and penalized 50% less than unplanned outages. Annual utility targets for planned interruptions are set using a three-year rolling average, with a two-year lag. (That is, the 2015-16 target would be the average over the 2011-12 to 2013-14 period.) Unplanned outage targets are set using a combination of utility and industry average for Low Voltage (LV), Extra High Voltage (EHV), and 132kV. Exceptional events are excluded from the performance data. Utilities can propose alternative targets in their well-justified business plans.
Guaranteed Standards of Performance	Penalty: Direct payments to each customer affected, typically of approximately £30/customer	Customers are eligible for direct payment of specific fixed amounts where a utility fails to deliver specified minimum levels of performance. For example, if the duration or frequency of interruptions exceed a pre-specified level, the utility must make a payment to a customer. Vulnerable customers on the Priority Service Register will receive automatic payments, while other customers will need to apply to their utility for payment.
Health and Load Indices	Penalty for under-delivery equal to reduced future allowed revenues and 2.5% of the value of the under delivery, or a reward for over-delivery equal to 2.5% of the incremental costs associated with over delivery and an upward adjustment to future allowed revenue.	Risk reduction associated with the condition and loading of assets. These metrics encourage longer-term strategies by linking the longer-term reliability benefits of healthier and less highly-loaded assets to a measurable deliverable within the price control.

Source: Ofgem 2012b, Ofgem 2013b

Scorecard for Outputs

To facilitate comparison across companies, Ofgem intends to develop scorecards for each of the companies' performance across the categories of output. Although the details have not yet been fleshed out, the scorecard will measure performance relative to a normalized baseline, as presented in the illustrative example below.

Figure 9. Illustrative Scorecard for Outputs



Source: (Ofgem 2010)

Lessons Learned

Under RIIO, a suite of performance incentive mechanisms, together with a comprehensive revenue cap mechanism, has been designed to encourage utilities to meet the needs of their customers in a cost-effective manner. Even though this new PBR framework is still being developed and has yet to be applied, several lessons can be drawn from the UK experience.

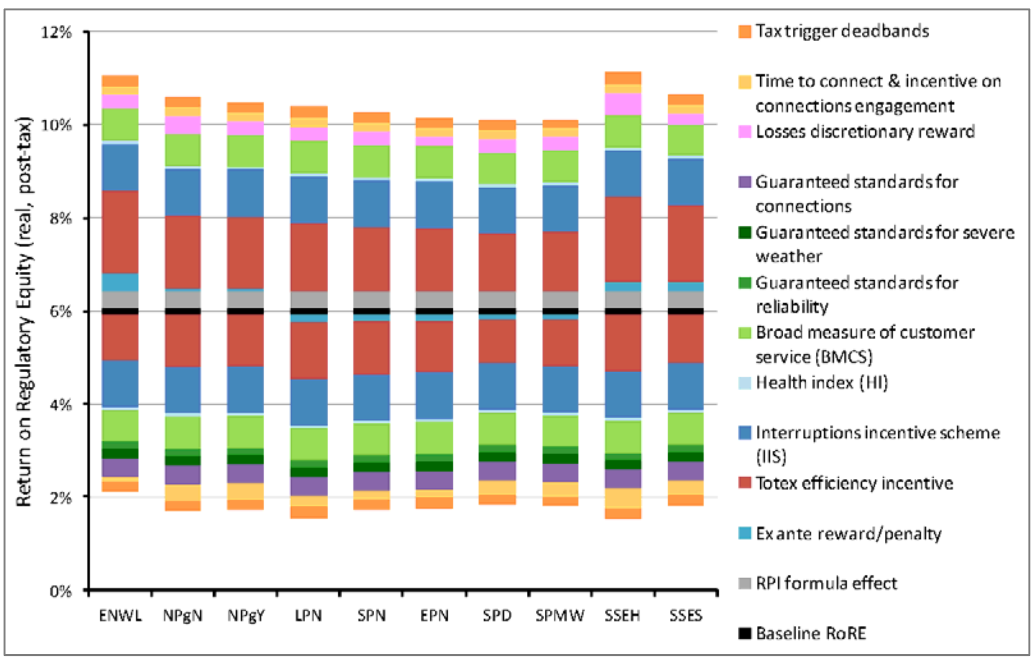
The evolution of the UK PBR framework provides an indication of the limitations to the simpler version of performance-based regulation that has been in place in the US, and the UK experience mirrors some of the challenges with PBR that US regulators have wrestled with in recent years. Many of the new RIIO elements described above (e.g., expanding the price control period, more focus on outputs, more attention to future planning in the business plans, increased use of capital cost trackers), reflect the aspects of simple PBR that have been insufficient in achieving PBR's ultimate goals. Regulators in the US who are looking to PBR as a new utility regulatory model should take note of the implications of these new RIIO elements.

One of the key lessons from the evolution of PBR in the UK relates to regulatory engagement. When PBR was introduced in the UK, and shortly after in the US, it was referred to as "hands-off" regulation. For example, the California PUC wrote that it hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3). However, the experience from the UK is just the opposite. It is clear that the new RIIO mechanism will requires significant utility and regulatory resources up front due to the extensive nature of the business plan development and review process, as well as the up-front effort necessary to create balanced and effective performance incentive mechanisms. Note that over the last five years, the number of Ofgem employees have doubled to more than 700 full-time employees.[30] Even after the development and approval of the utility business plan, Ofgem will probably need to dedicate considerable resources to the oversight and implementation of the performance incentives and the other components of the RIIO mechanism.

Relative to performance incentive mechanisms in the United States, RIIO places a large amount of revenues at stake. Potential rewards and penalties for outputs under the environmental, customer satisfaction, social obligations, and connections categories equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

These performance incentive mechanisms are integrated into a revenue cap plan that increases revenues each year at the rate of inflation and provides utilities with the ability to retain a significant portion of any cost efficiency savings. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 10. Plausible ROE Ranges for UK Distribution Utilities



Source: Ofgem 2014b, page 46

30 The number of permanently-employed staff at Ofgem has grown from 310 employees in 2008/2009 to 761 in 2013/2014 (Ofgem 2009; Ofgem 2014a).

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been "appropriately calibrated" (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

The RIIO process for developing performance incentive mechanisms relied upon significant amounts of stakeholder feedback, ranging from utilities to consumer groups. However, not all of the performance incentive mechanisms appear to have been fully developed yet, particularly for stakeholder and customer engagement. This is perhaps not surprising, as metrics based upon more qualitative data are difficult to define and can be difficult to administer. Lessons learned from the UK's experience with these more qualitative performance incentive mechanisms will be instructive for the development of similar valuable, but difficult-to-quantify performance targets elsewhere.

RIIO's performance targets are generally linked directly to utility business plans or industry-wide performance levels, which helps to ensure that the targets are reasonable and that the utilities will have the funds required to make investments to meet these targets. In some cases, such as interruptions and availability, rewards and penalties are based on customer willingness-to-pay surveys in order to balance the value of improved reliability with the associated costs.

Lastly, RIIO's use of "reputational" incentives for reducing carbon emissions provides an example of how simply displaying a comparison of utility performance in an easily and publicly accessible manner can encourage utilities to take steps to improve their performance, particularly for areas that are important for customers, such as carbon emissions. While the reputational incentive may not always be sufficient for achieving the level of performance desired, it represents a relatively simple and risk-free first step. Moreover, it allows data collection processes and definitions to be standardized and clarified prior to applying high-stakes financial incentives.

New York

During the 1990s, New York experimented with numerous performance incentive mechanisms for its electric and gas utilities. For example, the 1991 Measured Equity Return Incentive Program (MERIT) for Niagara Mohawk Power Company was designed to address a variety of aspects of the company's operations, including nuclear plant performance, the amount of payments to outside law firms, and environmental performance. The program resulted in significant improvements at Niagara Mohawk, and various performance incentive mechanisms were subsequently adopted at other New York utilities, generally under a comprehensive PBR plan with a price cap (Biewald et al. 1997).

The breadth of performance incentive mechanisms in use in New York was substantially reduced following restructuring as generation assets were spun off and subjected to the discipline of the market. Recently, however, New York has developed a renewed interest in performance incentive mechanisms as a means of reshaping utility incentives. In April 2014, the New York Public Service Commission (PSC) initiated the Reforming the Energy Vision docket with the goal of better aligning utility interests with state energy policy objectives. Although the docket is currently on-going, the initial straw proposal envisions moving toward a more "outcome-based approach to ratemaking" with metrics based on state energy policy goals (NY DPS Staff 2014).

A key component of the Reforming the Energy Vision (REV) proceeding is the desire to place distributed energy resources on a level playing field with traditional investments. While the REV proceeding is expected to develop a new ratemaking framework to achieve this goal, New York is already taking steps toward a new regulatory paradigm. In December 2014, the PSC approved incentives to reward the use of cost-effective distributed energy resources through a project called the Brooklyn Queens Demand Management (BQDM) program.

The Brooklyn Queens Demand Management program was proposed by Consolidated Edison Company (ConEd) to address load growth in the Brooklyn and Queens areas of New York. Rather than constructing a new area substation, a new switching station, and new subtransmission feeders (at a cost of approximately $1 billion), ConEd proposed to implement a portfolio comprised of distributed energy resources and other low-cost traditional utility-side solutions to address the forecasted summer overloads at a much lower cost (NY PSC 2014).

The PSC found that the BQDM project and associated incentives represented a valuable opportunity to explore changes to traditional utility operations and ratemaking, stating "this Commission must itself innovate in order to support innovation by utilities and third parties" (NY PSC 2014, 15). In order to ensure that the utility is indifferent to investments in distributed energy resources and traditional infrastructure investments, the Commission approved several financial incentives for ConEd. Specifically, the PSC approved:

- A regulated return on the alternative investments,
- A 10-year amortization period for the investments,

- A 100 basis point ROE adder on BQDM program costs tied to the achievement of specific outcomes related to achieving a certain capacity of alternative measures, increasing diversity of distributed energy resource vendor market, and implementing a portfolio that has a lower cost than the traditional solution. These performance incentives are defined in Appendix B of the order as follows (NY PSC 2014):

    1) Quantity of Alternative Measures:

        a. Metric: Capacity of alternative measures installed

        b. Target: 41 MW

        c. Financial incentive: 45 basis points for meeting or exceeding target

    2) Diversity of DER Vendor Marketplace:

        a. Metric: Normalized entropy index, calculated as follows:

$$normalized\ entropy\ index = \frac{\sum_{i=1}^{N} S_i \ln(S_i)}{\ln(N)}$$

        Where N is the number of DER Providers and S_i is the share, in MWh, of each provider in the selected portfolios.

        b. Target: Baseline set at 0.75; maximum reward occurs at 1.0

        c. Financial incentive: One basis point earned for each 0.01 increase in the normalized entropy index above the baseline (up to 25 basis points).

    3) Reduction in Dollar/MW Costs:

        a. Metric: Assembling a portfolio of solutions that achieves a lower $/MW lifecycle cost (based on the net present value) than the traditional investment solution (30 basis points). The lifecycle costs will be calculated by January 31, 2017, using the Company's then-applicable Weighted Average Cost of Capital.

        b. Target: Baseline set at $6 million/MW based on the Company's estimated NPV revenue requirement of 915.6 million to achieve a total capability of 152 MW.

        c. Financial Incentive: For every full 1% reduction in the $/MW of the BQDM Program portfolio and associated investments relative to the baseline, the Company may earn 1 basis point (up to 30 basis points.)

Initial Assessment of the BQDM Performance Incentive Mechanisms

The adoption of the above performance incentive mechanisms provides a clear signal to New York's utilities that distributed energy resources should be valued in a manner similar to traditional investments, and that reducing costs for consumers will be rewarded. The three performance incentive mechanisms (quantity of alternative resources installed, diversity of market, and cost) simultaneously address several of the commission's objectives.

In addition, the commission's choice of incentive formulas appears reasonable. The Company will only be rewarded if it installs the amount of alternative resources required (41 MW), but will not be rewarded more for installing more resources than needed, thereby avoiding an incentive to procure excessive amounts of alternative resources. The choice of linear financial rewards for the diversity index and cost provide incentives to achieve the highest levels reasonably possible, while rewarding the Company proportionately for any improvements made.

However, two aspects of the performance incentive mechanism have some room for improvement: (1) the linkage between rate base and the financial incentive, and (2) the definition of the diversity index. The financial reward's direct link to rate base (through virtue of being an ROE adder) implies that increasing rate base will in turn increase the Company's financial reward, which may exacerbate the Averch Johnson effect and lead the utility to make unnecessary rate base investments. This issue is explored in more detail in the FERC Transmission Bonus ROE case study later in this appendix.

The second issue concerns the diversity index definition. On January 12, 2015, ConEd filed a petition requesting clarification and modification to several aspects of the performance incentive mechanism (ConEd 2015):

- First, the Company pointed out that, as currently defined, the diversity index focuses on the number of vendors who are awarded contracts through the BQDM Program, but does not include direct customers and subcontractors. It is likely that the Commission is also interested in increasing the number of customers who provide distributed energy resources (such as commercial buildings providing demand response) and vendor subcontractors, and therefore the diversity index should be expanded to include these entities.
- Second, the diversity index, as currently defined, does not measure diversity of technologies. If this is a priority for the Commission, this measure of diversity should also be included in the index.
- Third, the specific calculation of the entropy index appears to reward equal contributions of capacity more than the number of vendors. That is, under the current metric definition, the Company would earn the maximum reward if two vendors each contribute 50% or if five vendors each contribute 20% of the capacity.

For these reasons, ConEd has proposed that Staff and the Company collaborate to modify the diversity index metric.

Illinois

In October 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law by Illinois Governor Pat Quinn. The law authorized 10-year, $2.6 billion smart grid investment by Commonwealth Edison (ComEd) designed to modernize and upgrade its electric system, including investments in smart grid infrastructure ranging from distribution automation and substation upgrades to smart meters for customers.

To ensure that customers receive benefits from the upgrades, the law also set reliability and other performance metrics to be achieved incrementally over ten years. These metrics include:

- 20% improvement in SAIDI
- 15% improvement in CAIDI
- 20% improvement in SAIFI
- Improvement in total number of customers who exceed service reliability targets by 75%
- 90% reduction in estimated bills
- 90% reduction in consumption on inactive meters
- 50% reduction in unaccounted for energy
- $30 million reduction in uncollectible expense

The performance incentives were set to be penalty only, with progress required in equal segments for each goal in each year. For each year that a goal is unmet, the utility faces a reduction in return on equity by 5-7 basis points per goal, with the penalty increasing over time. To avoid a penalty, 100% progress is required on reliability goals, and 95% progress required on other goals (220 ILCS 5 §16-108.5).

While explicitly addressing the basic aspects of electricity delivery listed above, the performance incentive mechanisms established by EIMA failed to address numerous other potential benefits of smart grid investments for consumers and the environment. For this reason, several consumer and environmental groups initiated discussions with ComEd to track numerous additional performance metrics.

Expansion of Performance Metrics

In 2013 environmental and consumer groups reached an agreement with ComEd to track numerous additional performance metrics. The list of performance metrics co-developed by the utility and stakeholders is extensive, and includes the following (ComEd 2014):

- Reductions in greenhouse gas emissions (as measured through load shifting, system peak reductions, and reduced truck rolls due to smart meters)
- Load served by distributed resources

- Time required to connect distributed resources to grid
- Peak load reductions (enabled by demand response)
- Products with grid interoperability (retail product market animation)
- Customers enrolled in time-varying rates (e.g., peak time rebates)
- Customer awareness and use of ComEd's web portal for viewing usage information

Although these performance metrics do not include any rewards or penalties, they provide valuable information for regulators and stakeholders to monitor whether customers are receiving the full benefit of the multi-billion dollar smart grid infrastructure investment. In addition, these metrics provide valuable information going forward for regulators if it is determined that a financial reward or penalty is warranted.

Metric Definitions

More than sixty performance metrics were developed to be tracked. The table below lists and defines many of these metrics. A nearly complete list can be found in ComEd's 2014 Smart Grid Progress Report, while the greenhouse gas metric details were filed in Illinois Commerce Commission Case Number 14-0555.

Table 21. Selected Smart Grid Metrics in Illinois

Customers enrolled in Peak Time Rebate, Real Time Pricing, and other dynamic and time variant prices	Residential Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in each delivery class.
	Residential Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data Interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in each delivery class.
	Small Commercial Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in the delivery class.
	Small Commercial Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in the delivery class.
Customer-side-of-the-meter devices sending or receiving grid related signals	Number of ComEd AMI meters with consumer devices registered to operate with the Home Area Network ("HAN") chip by tariffs under which customer receives delivery.
AMI Meter failures	Number of advanced meter malfunctions where customer electric service is disrupted.

Customers with net metering	Number of customers enrolled on Net Metering tariff and the total aggregate capacity of the group.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs such as the PTS program as a percentage of all demand response in ComEd's portfolio.
Customer Complaints	Number of formal ICC complaints, informal ICC complaints, and complaints escalated to ComEd's Customer Relations or Customer Experience departments related to AMI Meter deployment, broken down by type of complaint and resolution. AMI Meter deployment includes AMI Meter installation, functioning or accuracy of the AMI meter, and HAN device registration.
Customer premises capable of receiving information from the grid	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system.
	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system, divided by the total number of AMI meters installed.
	Number of customers who have accessed the web-based portal as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
	Number of customers who can directly access their usage data as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs as a percentage of all demand response in ComEd's portfolio.
Reduction in greenhouse gas emissions enabled by smart grid	Load shifting: ComEd will calculate marginal emissions changes due to load shifting for smart meter customers versus non-smart meter customers at an hourly level.
	Reduction in system peak: ComEd will partner with a third-party entity to conduct a dispatch study of the impact of load shifting and peak load reduction enabled by smart meters, including increased adoption of electric vehicles, on PJM's system, and determine a GHG metric around resulting changes in generator dispatch and expected plant closures.
	Reduced truck rolls: ComEd will compare the aggregate annual GHG emissions of all meter reading vehicles assigned to a specific operating center in the year in which Smart Meters are deployed in that same operating center, to the average aggregate annual GHG emissions of the three years prior to the year in which Smart Meter installation for that specific operating center is completed. GHG emissions will be calculated by measuring fuel consumption and converting into fuel emissions via the Climate Registry emission factor.

Distributed generation projects	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
Load served by distributed resources	Total sales of electricity to the grid from distributed generation (Rider POG or POG-NM customers) divided by zone energy plus distributed generation sales, with all data provided in sortable format.
System load factor and load factor by customer class	Total annual consumption for AMI meters (including, separately, small commercial customers) divided by the average demand across all AMI meters over the 5 peak hours multiplied by 8760 hours by customer class.
Products with end-to-end interoperability certification	ComEd will conduct an annual survey through a third-party provider to evaluate how products are being introduced in the smart grid enabled marketplace.
Network nodes and customer interfaces monitored in "real time"	Network nodes and customer interfaces monitored in "real time"
Grid connected energy storage interconnected to utility facilities at the transmission or distribution system level	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	ComEd will conduct an annual survey through a third-party provider to estimate similar measures of non-utility storage units.
Time required to connect distributed resources to grid	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to distribution grid.
	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to transmission grid.
Grid assets that are monitored, controlled, or automated	Number and percentage of ComEd substations (Distribution Center Substations ("DCs"), Substations ("SSs") Transmission Substations ("TSSs") and Transmission Distribution Centers ("TDCs")) monitored or controlled via Supervisory Control and Data Acquisition ("SCADA") systems.
	Number and percentage of ComEd distribution circuits (4kV, 12kV and 34kV) equipped with automation or remote control equipment including monitor or control via SCADA systems.

Customers connected per automated circuit segment	Average number of customers per automated three phase 12kV line segment. (An "automated line segment" is a segment of 12 kV three phase mainline circuit between automated devices which include circuit breakers, reclosers, automated switches, etc.)
Improvement in line loss reductions enabled by smart grid technology	Stakeholders agreed upon several research priorities for research about line loss reductions. ComEd is conducting a feasibility study regarding use of Voltage Optimization. Voltage Optimization is combination of Conservation Voltage Reduction and Volt-VAR Optimization. These programs are intended to reduce end use customer energy consumption and peak demand while also reducing utility distribution system energy losses.
Voltage and VAR controls	Number and percentage of distribution lines using sensing from an AMI meter as part of ComEd's voltage regulation scheme.
Tracking Actual Costs	The actual cost of the AMI deployment costs that ComEd has incurred, including both one-time and on-going operating costs.
Customer Applications	Bill impacts associated with the costs for implementation of ComEd's AMI Plan for low, average, and higher usage level customers pursuant to approved rates and surcharges.
	Number of customers that have created and viewed an account on ComEd.com – by usage levels, customer class, and low income customers. An account on ComEd.com is necessary for viewing the web portal.
	Number of customers with ComEd.com accounts that have viewed the web portal - by usage levels, customer class, and low income customers
	Change in customers' energy consumption for customers that have viewed the web portal. ComEd will work with the web presentment vendor to define business processes necessary to track an energy usage impact of accessing the web portal.
	Number of customers enrolled in the Residential Real Time Pricing ("RRTP") program (ComEd's hourly pricing program) by usage levels, customer class, and low income customers.
	Number of customers enrolled in ComEd's PTR program by usage levels, customer class, and low income customers.
Customer Outreach & Education	Awareness and Education - Awareness and understanding of AMI technology and benefits (survey metric)

Hawaii

In 2010, Hawaii adopted revenue decoupling for its electric utilities in order to encourage renewable resources, distributed generation, and energy efficiency. When it adopted the decoupling mechanism, the Commission declined to adopt any performance incentive mechanisms, as the decoupling mechanism did not place a hard cap on allowed revenues. In 2013, however, the Commission determined that it was appropriate to reexamine the decoupling mechanism, particularly its revenue adjustment mechanism, and determine whether any performance metrics or performance incentive mechanisms should be adopted.

Performance Metrics

Numerous parties suggested performance metrics for tracking the utilities' ability to achieve renewable energy goals, ensure reliability, and reduce costs. As a result, the Hawaii Public Utilities Commission adopted nearly 30 performance metrics, including:

- **System Reliability:** System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI)
- **Generator Performance:** Equivalent Availability Factor (EAF), Equivalent Forced Outage Rate Demand (EFORd), Equivalent Forced Outage Factor (EFOF)
- **Independent Power Producer (IPP) energy:** Measured as IPP energy / Net to System Energy
- **Renewable Energy:** System renewable energy (excluding customer-sited generation), total renewable energy (including distributed generation), renewable energy curtailments, and RPS compliance
- **Safety:** Public safety incidents, employee injury and illness rate, employee lost time rate, emergency response time
- **Distributed Energy Resources:** Number of net metering program participants and capacity of net metering program, demand response and storage enrollments
- **Customer service:** call center performance, customer complaints, appointments met, metering and billing accuracy, survey responses
- **Cost:** Metrics providing breakdowns of the contributing cost components to customer rates, and unaccounted for energy (HI PUC 2014).

Further, the Commission ordered that these metrics be posted on the Companies' websites in order to facilitate ease of access for utility customers.

Proposed Performance Incentive Mechanisms

During the second phase of the proceeding, parties proposed various forms of revenue cap mechanisms together with performance incentive mechanisms thought to be readily quantifiable, objective, and immune from gaming. Proposals varied widely, from traditional reliability and call center performance incentive mechanisms, to innovative mechanisms targeting reductions in fossil fuel use and the quality of utility resource planning.

Blue Planet, an intervenor in the case, proposed two environmental performance incentive mechanisms:

1) Reduction in carbon intensity of generation (as measured from the current baseline trend), with a potential reward of up to three cents per share.

2) Interconnection and utilization of non-utility, non-fossil generation and demand response resources, with a potential reward of several cents per share.

The Consumer Advocate proposed several performance incentive mechanisms, the most innovative of which was a mechanism for measuring the quality of the utilities' resource planning process, including stakeholder engagement, range of resources modeled, and follow-through on previous plans. The basis for this performance incentive mechanism was the Commission's IRP Framework, which was initially adopted in 1992 and revised in 2011. This PIM is described in greater detail below.

<u>Resource Planning Performance Incentive Mechanism</u>

Under this PIM, performance will be scored based on compliance with six principles and their associated metrics:

1) **Stakeholder Engagement:** The planning process should allow for meaningful stakeholder involvement throughout the planning process, and should incorporate stakeholder recommendations in the planning process as appropriate.[31]

   Metrics: Whether stakeholder input was adequately considered in establishing:

   a. Planning objectives
   b. Range of scenarios
   c. Resource options
   d. Assumptions, risks, and constraints
   e. Screening of options
   f. Criteria for ranking of resource plans
   g. The choice of final plan

[31] This principle measures the extent to which the Companies have complied with the Framework requirement V.B.1.b, which states: "consider the input, comments and suggestions provided by Advisory Group members and the general public, to the extent feasible," as well as compliance with requirement V.C.4.a (identification of planning objectives with input from advisory group).

2) **Evaluation of Resources:** The planning process should investigate a wide array of existing and emerging supply-side resources, including generation, transmission, and distribution opportunities, including utility-side smart grid options; as well as a wide array of existing and emerging demand-side options such as energy efficiency, demand response, distributed generation, storage technologies, and customer-facing smart grid options.[32]

   Metrics:

   a. Were appropriate modeling tools used?
   b. Were existing system and conditions adequately characterized?
   c. Was the range of new resources considered adequate?
   d. Were new resource options analyzed on a consistent and comparable basis, using reasonable estimates of the benefits and costs?
   e. Was adequate analysis performed to determine the risks and constraints of new resources?
   f. Did the analysis produce credible and reasonable results?

3) **Resource Scenarios and Resource Plans:** The planning process should include a transparent approach to identifying a reasonable set of resource scenarios and resource plans. From this set, the resource plans should be transparently prioritized or ranked based on previously identified key criteria such as minimization of the present value of revenue requirements, meeting environmental goals, maximizing customer benefits, and balancing risks.[33]

   Metrics:

   a. Was an appropriate range of scenarios examined (e.g., appropriate incorporation of various uncertainties; were scenarios extremes, or did they resemble what might actually occur)?
   b. Was there evaluation of an appropriate number of resource plans to ensure results of the process are meaningful?
   c. Were the criteria for determining the best resource plan clearly articulated at the outset?

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[32] This principle measures compliance with several of the Framework requirements identified in section V.C., including V.C.2 (“Characterization of existing system and conditions”), V.C.3 (“Identification of uncertainties and factors that affect utility planning”), V.C.5 (“Determination of planning scenarios and forecasts”), V.C.6 (“Identification of resource options”), V.C.7 (“Models”), and V.C.8 (“Analyses”).

[33] This principle measures compliance with Framework requirements V.C.8. (Analyses), V.C.6.d (screening out infeasible or inappropriate resource scenarios), V.C.4.b and V.C.4.c (use of planning principles), and V.C.9 (determination of resource plans).

d. Was the weighting and ranking to determine the best resource plans transparent and did it incorporated principles and objectives previously identified?
e. Was sufficient consideration given to whether resource plans are able to meet state energy policy goals?
f. Were measures and strategies identified to address limitations and constraints that may impact the utility's ability to achieve state energy policy goals.

4) **Action Plan:** The planning process should include an action plan that enables the utility to translate the results of its analyses into development of actual resources.[34]

Metrics:

a. Does the Action Plan articulate next steps for implementing those resources that will be implemented in the short-term?

b. Does the Action Plan identify and address barriers to developing identified short-term resources?

5) **Strategic Planning:** This principle is intended to ensure that the companies' investments are guided by a long-term strategic vision that addresses the challenges faced by the companies and positions them to allow for agile response to changing system conditions.[35]

Metrics:

a. Do the companies clearly define a long-term strategic vision?
b. Does the strategic vision discuss steps that the companies need to take in order to move toward a more sustainable business model?
c. Does the strategic vision discuss the companies' strategy for ensuring that the investments made will enable the Companies to respond with agility to a range of possible future circumstances?
d. Are specific desired outcomes defined and initiatives identified to achieve such outcomes?

6) **Follow-Through on Previous Action Plans:** Demonstrated progress should be made in undertaking and successfully completing initiatives identified in the previous action plan. The companies should not be penalized for making prudent adjustments to the action plan in light of new information or changed circumstances, but any such changes must be sufficiently justified by the companies.

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[34] This principle measures compliance with Framework requirements V.C.9.

[35] This principle addresses the desire of the Commission to ensure that the Companies face adequate "incentives to make necessary and/or appropriate changes to utility strategic plans and action plans," as evidenced by this being a major topic for comment in Order No. 31635.

Metrics:

Metrics should be set at the conclusion of each major planning process, based on the specific investments, activities, and costs identified in the action plan. How well these are achieved will then be evaluated at the commencement of the following planning process.

Example: Did the Companies develop X resource in Y timeframe within Z cost?

Utility performance on each metric would be rated as “inadequate,” “adequate,” or “exemplary.” A rating of “inadequate” would correspond to a score of 1.0, while “exemplary” would correspond to a score of 3.0. The scores for each metric would then be averaged for each principle.

The overall scorecard would be completed by an independent evaluator for the IRP process or similar entity in another planning process. The scorecard would be completed by the independent evaluator through a two-step process:

1) For the first principle regarding stakeholder engagement, stakeholders would complete a survey. If a stakeholder wished to score performance on a metric as either “inadequate” or “exemplary,” the stakeholder would be required to provide a detailed explanation describing their rationale. The independent evaluator would then review all of the stakeholder scores and assign a composite score for each metric, taking into account the evidence presented by stakeholders.

2) The independent evaluator would conduct an evaluation of the planning process and score the companies’ performance on each metric.

The scoring of the companies’ planning performance would not replace the current evaluation process in which the independent evaluator files interim reports and a certification report to the commission, but would occur in addition to this process. The PIM scorecard would serve to summarize the overall conclusions of the independent evaluator.

The completed scorecard would then be filed together with any other final certification or process report by the independent evaluator. The companies would then be allowed to respond to and rebut the scores received. The commission may, at its discretion, also allow other stakeholders to comment on the scorecard and the companies’ rebuttal. After considering any responses, the commission would then issue a final ruling regarding any penalty or reward.

Current Status of Performance Incentive Mechanisms

As of this writing, the commission had yet to issue an order regarding the proposed performance incentive mechanisms.

Performance Incentives Related to Fuel Adjustment Clauses

Fuel adjustment clauses have been widely adopted in many states to reduce the need for frequent rate cases due to fluctuations in fuel costs. However, these fuel adjustment clauses can reduce the incentive for utilities to operate efficiently, and can skew utilities' resource investment decisions, as the utilities are insulated from fuel price volatility. To address this, some jurisdictions modified their fuel cost pass-through mechanisms to allow only partial pass-through, or to make the pass-through contingent on the utility achieving a certain level of power plant efficiency. For example, prior to restructuring, New York adopted a mechanism by which utilities would absorb a portion (ranging from 20% to 40%) of fuel costs above its forecast. If costs came in below the forecast, the utility would retain a portion (20% to 40%) of the savings (Knittel 2002).

In Hawaii, the Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor. However, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

Conditioning cost recovery on power plant efficiency or using shared savings mechanisms can help distribute risk between the utility and ratepayers, and have been shown to be effective for improving power plant efficiency. A 2002 study analyzed the impacts of modified fuel adjustment clauses by comparing the efficiency of power plants under a full fuel cost adjustment clause with the efficiency of plants under a modified mechanism in which the utility must bear some of the risk for fuel cost overruns and can keep a portion of such savings. The author found that modified fuel adjustment clauses resulted in 9 percent more output produced for a given amount of input than mechanisms that passed through all of the fuel costs (Knittel 2002). This finding suggests that full fuel adjustment clauses do not encourage efficiency, but that a modified approach that incorporates shared savings can improve efficiency.

On a cautionary note, shared savings approaches related to fuel costs can be vulnerable to manipulation. For example, Nicor Gas, the largest gas utility in Illinois, has been ordered to refund more than $72 million to ratepayers due to allegations of fraud. The utility operated under an incentive that set a gas cost benchmark, and then allowed Nicor to keep half of any savings it achieved. According to allegations, the company manipulated its gas storage operation by improperly releasing low-cost gas put in storage under very low prices years before to artificially produce "savings" (Daniels 2013).

FERC's Bonus ROE for Transmission Projects

Pursuant to the Energy Policy Act of 2005, the Federal Energy Regulatory Commission (FERC) developed incentive-based rate treatments for transmission investments. As part of FERC's Order No. 679, transmission developers (utilities and stand-alone transmission companies) received higher rates of return on equity for new transmission investment in order to improve reliability and reduce congestion in order to lower delivered energy costs.

In practice, however, the incentive may have had effect of increasing delivered energy costs. By applying the ROE adder to the project's actual costs, developers were given a perverse incentive to *increase* the project costs (through, for example, delaying the construction), because they would earn the higher ROE on the total costs of the project. In this way, the incentive actually rewarded projects that came in over budget (American Forest & Paper Association, et al. 2011). It has been estimated that consumers in New England will pay more than an additional $100 million in adder charges for transmission projects because these projects have greatly exceeded their original costs (New England Conference of Public Utility Commissioners v. Bangor Hydro-Electric Co 2008).

Compounding this effect was the inability to demonstrate that the incentive would result in net benefits, as the Order did not require quantifying the benefits in relationship to the costs of the incentives. Further, applicants seeking the incentives were not required to show that the project would not be developed without the incentives (American Forest & Paper Association, et al. 2011).

Jim Tracy, Sacramento Municipal Utility District Chief Financial Officer, was one of many interveners who submitted comments in response to the FERC's Notice of Inquiry regarding the incentive mechanism. Having been involved in financing a large number of infrastructure projects, including transmission, distribution, and generation projects, Mr. Tracy noted that even if the net impact of the incentive was positive, the "costs of the incentives were almost certainly more than needed" (American Forest & Paper Association, et al. 2011, 143). He further commented that Commission's incentive rate may have resulted in excess transmission capacity.

According to Mr. Tracy, lenders are not influenced by higher rates of return for specific types of projects, but rather by the availability of mechanisms that reduce the risk that revenues will be interrupted during the recovery period. Further, because a utility's investment funds are limited, higher returns on certain types of projects can result in skewing the utility's investment choices away from alternatives that may be better for ratepayers (American Forest & Paper Association, et al. 2011).

APPENDIX B – DATA SOURCES AND AVAILABILITY

The following tables contain data sources for the metrics discussed in this handbook. Table 22 includes metrics, metric formulas, and data sources, and Table 23 includes notes about the availability of data and weblinks. Note that the data sources presented below may not provide all the data needed for performance metrics, and we have not assessed the quality or reliability of the data in these sources.

Many of the metrics discussed in this report can be obtained or calculated using data from federal agencies and other national organizations. Where data are not available from a national source, regulators can collect them directly from their utilities (indicated by "Collect from utility" in the Data Source column). However, regulators should assure that the data collected from utilities are well-defined, consistent across utilities, and well understood, as discussed in Chapter 3.

Table 22. Metric Formulas and Data Sources

Performance Dimension	Metric or metric group	Metric formula	Data Source
Reliability	System Average Interruption Duration Index (SAIDI)	Total minutes of sustained customer interruptions / total number of customers	EIA Form 861
	System Average Interruption Frequency Index (SAIFI)	Total number of sustained customer interruptions / total number of customers	EIA Form 861
	Customer Average Interruption Duration Index (CAIDI)	Total minutes of sustained customer interruptions / total number of interruptions	Collect from utility
	Momentary Average Interruption Frequency Index (MAIFI)	Total number of momentary customer interruptions per year / total number of customers	Collect from utility
	Power quality	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker.	Collect from utility
Employee Safety	Total Case Rate (TCR)	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[36]	OSHA Form 300

[36] 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Days Away, Restricted, and Transfer (DART) case rate	(Number of work-related days away from work and job transfers or restrictions times 200,000) / Employee hours worked	OSHA Form 300
	Days Away From Work (DAFWII) case rate	(Number of work-related days away from work times 200,000) / Employee hours worked	OSHA Form 300
Public safety	Incidents, injuries, and fatalities (electric)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity	Collect from utility
	Emergency response time (electric)	Percent of electric emergency responses within 60 min. each year	
	Incidents, injuries, and fatalities (gas)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause (corrosion, natural forces, excavation, other outside force, pipe/weld/joint/equipment failure, incorrect operation, other cause)	PHMSA Form F 7100.1
	Emergency response time (gas)	Average minutes for gas emergency response	Collect from utility
	Leak repair performance (gas)	Average days for repair of minor and non-hazardous leaks	
Customer Satisfaction	Call center answer speed	Percentage of calls answered within 30 seconds	Collect from utility
	Transaction surveys	Percentage of customers satisfied with their recent transaction with the utility	Collect from utility
	Customer complaints	Formal complaints to the Commission (number per 1,000 customers)	Collect from utility
	Order fulfillment	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled	Collect from utility
	Missed appointments	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises	Collect from utility
	Avoided shutoffs and reconnections	Disconnects and reconnections avoided by customer percentage of income payment plans or other means	Collect from utility
	Residential customer satisfaction	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index	J.D. Power Electric Utility Residential Customer Satisfaction Study℠, J.D. Power Gas Utility Residential Customer Satisfaction Study℠

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Business customer satisfaction	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index	J.D. Power Electric Utility Business Customer Satisfaction Study^{SM}, J.D. Power 2014 Gas Utility Business Customer Satisfaction Study^{SM}
Plant Performance	Fuel usage	Quantity of fuel burned	FERC Form 1
	Heat rate	Average BTU per kWh net generation	FERC Form 1
	Capacity factor	Average energy generated for a period / energy that could be generated at full nameplate capacity	FERC Form 1
Costs	Capacity costs	Cost per kW of installed capacity	FERC Form 1
	Total energy costs	Expenses per net kWh	FERC Form 1
	Fuel cost	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs	FERC Form 1
	Effective resource planning*	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.	third-party evaluator
	Cost-Effective Alternative Resources*	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment	Collect from utility
System Efficiency	Load factor	Sector avg load / sector peak load	Collect from utility
		Monthly system average load / monthly system peak load	FERC Form 1
	Usage per customer	Sector sales / sector number of customers	FERC Form 1 (electric), Form EIA-176 (gas)
	Aggregate Power Plant Efficiency	System average BTU per kWh net generation (heat rate)	FERC Form 1
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)	NERC Generating Availability Data System
		EFORd: variant of EFOR, measuring the probability that a unit will not meet its generating requirements demand periods because of forced outages or derates	NERC Generating Availability Data System
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings	NERC Generating Availability Data System
	Flexible Resources	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)	Collect from utility
	System losses	Total electricity losses / MWh generation, excluding station use	FERC Form 1
		Total gas losses / total sales	Form EIA-176

Performance Dimension	Metric or metric group	Metric formula	Data Source
Customer Engagement	Energy efficiency (EE)	Percent of customers per year participating in EE programs	Collect from utility
		Annual and lifecycle energy savings	EIA Form 861 (electric), collect from utility (gas)
		Annual and lifecycle peak demand savings (MW)	EIA Form 861
		Program costs per unit of energy saved (MWh or therm)	EIA Form 861 (electric), collect from utility (gas)
	Demand response (DR)	Percent of customers per year	EIA Form 861 and FERC F1
		Number of customers enrolled	EIA Form 861
		MWh of DR provided over past year	EIA Form 861
		Potential and actual peak demand savings (MW)	EIA Form 861
	Distributed generation (DG)	Number of installations per year	Collect from utility
		Net metering installed capacity (MW)	EIA Form 861
		Net metering MWh sold back to utility	EIA Form 861
		Net metering number of customers	EIA Form 861
		MW installed by type (PV, CHP, small wind, etc.)	EIA Form 861
	Energy storage	Number of installations per year	Collect from utility
		MW installed by type (thermal, chemical, etc.)	Collect from utility
		Percent of customers with storage technologies enrolled in demand response programs	Collect from utility
	Electric vehicles (EVs)	Number of EVs added to the grid each year	Collect from utility
		Percent customers with EVs enrolled in DR programs	Collect from utility
	Information availability	Number of customers able to access daily usage data via a web portal	EIA Form 861
		Percent of customers with access to hourly or sub-hourly usage data via web	Collect from utility
	Time-varying rates	Number of customers on time-varying rates / total customers	EIA Form 861
Network Support Services	Advanced metering capabilities	Number of customers with AMI and AMR	EIA Form 861
		Energy served through AMI	EIA Form 861
	Interconnection support	Average days for customer interconnection	Collect from utility
		Customer satisfaction with interconnect process	Collect from utility
	Third party access	Open and interoperable smart grid infrastructure that facilitates third-party devices	Collect from utility
		Third party vendor satisfaction with utility interaction	Collect from utility
	Provision of customer data	Customers able to authorize third-party access electronically	Collect from utility
		Percent of customers who have authorized third-party access	Collect from utility
		Third party data access at same granularity and speed as customers	Collect from utility

Performance Dimension	Metric or metric group	Metric formula	Data Source
Environmental Goals	SO_2 Emissions	Tons per year	EPA Air Markets Program Data
	Avg NOx Rate	lbs/MMBtu	EPA Air Markets Program Data
	CO_2 emissions	Tons CO_2 per year	EPA Air Markets Program Data
	Carbon intensity	Tons CO_2 / customer	EPA Air Markets Program Data and EIA 861
	System carbon emission rate	Tons CO_2 / MWh sold	EPA Air Markets Program Data and EIA 861
	Clean Power Plan (CPP) emission rate	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))	Collect from utility
	Fossil carbon emission rate	Tons CO_2 / MWh fossil generation	EPA Air Markets Program Data and EIA 861
	Fossil generation	Fossil percent of total generation	EIA Form 923 and EIA Form 860
	Renewable generation	Renewable percent of total generation	EIA Form 923 and EIA Form 860

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 23. Data Sources and Notes on Availability

Source	Notes on Availability	Link to Data
EIA Form 176	Form EIA-176 is designed to collect data on natural, synthetic, and other supplemental gas supplies, disposition, and certain revenues by state. It must be completed by interstate and intrastate natural gas pipeline companies; gas distribution companies; underground gas storage operators; synthetic natural gas plant operators; field, well, or processing plant operators that deliver natural gas directly to consumers (including their own industrial facilities) other than for lease or plant use or processing; field, well, or processing plant operators that transport gas to, across, or from a state border through field or gathering facilities; and liquefied natural gas (LNG) storage operators, both peaking facilities and marine terminals. (U.S. EIA 2015a)	http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1
EIA Form 860	Form EIA-860 collects data on the status of existing, grid connected electric generating plants with a nameplate capacity of 1 MW or greater and associated equipment (including generators, boilers, cooling systems and air emission control systems) in the United States, and those scheduled for initial commercial operation within 10 years (coal or nuclear) or 5 years (other energy sources). (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia860/
EIA Form 861	All electric power industry entities complete 861, including: electric utilities, all DSM Program Managers, wholesale power marketers, energy service providers (registered with the states), and electric power producers. (U.S. EIA 2014c)	http://www.eia.gov/electricity/data/eia861/
EIA Form 923	Form EIA-923 collects information on the operation of electric power plants and combined heat and power (CHP) plants in the United States. Form EIA-923 is a mandatory report for all grid-connected electric power and CHP plants that have a total generator nameplate capacity (sum for generators at a single site) of 1 MW or greater. (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia923/
EPA Air Markets Program Data	Data are available for power plants that are subject to various market-based regulatory programs, including the Acid Rain Program, NOx Budget Trading Program, and Clean Air Interstate Rule.	http://ampd.epa.gov/ampd/QueryToolie.html
FERC Form 1	FERC Form 1 is required for each major electric utility, licensees, or other (as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101)). Major is defined as having in each of the three previous calendar years, sales or transmission service that exceeds one of the following: (1) 1,000,000 MWh or more of total annual sales; (2) 100 MWh of annual sales for resale; (3) 500 MWh of annual power exchange delivered; or (4) 500 MWh of annual wheeling for others (deliveries plus losses). (FERC 2015)	http://www.ferc.gov/docs-filing/forms/form-1/data.asp

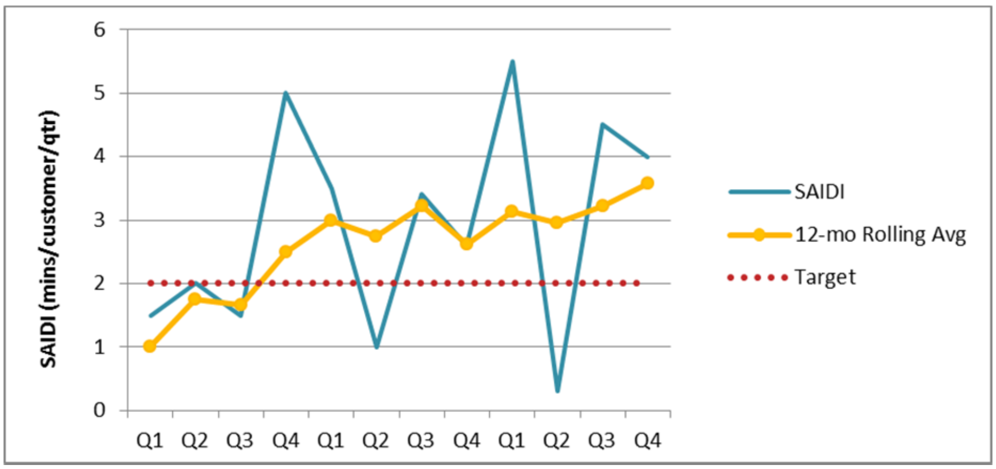
J.D. Power Electric Utility Business Customer Satisfaction Study^{SM}	Within each of the four geographic regions included in the study, utility providers are classified into one of two segments: large (serving 85,000 or more business customers) and midsize (serving between 25,000 and 84,999 business customers). The study is conducted annually. The 2014 Electric Utility Business Customer Satisfaction Study is based on responses from > 23,700 online interviews with business customers that spend at least $250 monthly on electricity.	http://www.jdpower.com/press-releases/2014-electric-utility-business-customer-satisfaction-study
J.D. Power Electric Utility Residential Customer Satisfaction Study^{SM}	The Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 100,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers. The Study has been conducted annually for 16 years. The 2014 Study was based on responses from 104,460 online interviews conducted from July 2013 - May 2014 among residential customers of the 138 largest electric utility brands across the U.S.	http://www.jdpower.com/press-releases/2014-electric-utility-residential-customer-satisfaction-study
J.D. Power Gas Utility Business Customer Satisfaction Study^{SM}	The study measures business customers' satisfaction with the nation's 55 largest gas utilities in four U.S. geographic regions: East, Midwest, South, and West. The study examines satisfaction across six factors—billing and payment; corporate citizenship; price; communications; customer service; and field service.	http://www.jdpower.com/resource/us-gas-utility-business-customer-satisfaction-study
J.D. Power Gas Utility Residential Customer Satisfaction Study^{SM}	The study ranks large and midsize utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 125,000 and 399,999 residential customers, and companies in the large utility segment serve 400,000 or more residential customers. The Study has been conducted annually for 13 years. The 2014 Gas Utility Residential Customer Satisfaction Study is based on more than 69,800 responses from residential customers of 83 large and midsize gas utilities across the continental United States. The study was fielded between September 2013 and July 2014.	http://www.jdpower.com/press-releases/2014-gas-utility-residential-customer-satisfaction-study
NERC Generating Availability Data System	For conventional generating units with a nameplate capacity of 20 MW and larger, GADS reporting is mandatory. Renewable generation (i.e., wind and solar) is not required to report. Conventional generating units less than 20 MW nameplate are invited to report to GADS on a voluntary basis.	http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx
OSHA Form 300	The Occupational Safety and Health (OSH) Act of 1970 requires certain employers to prepare and maintain records of work-related injuries and illnesses. OSHA Form 300 is only available for a small portion of all private sector establishments in the U.S. (80,000 out of 7.5 million total establishments).	https://www.osha.gov/pls/odi/establishment_search.html, http://ogesdw.dol.gov/views/searchChooser.php
PHMSA Form F 7100.1	Title 49 of the Code of Federal Regulations (49 CFR Parts 191, 195) requires pipeline operators to submit incident reports within 30 days of a pipeline incident or accident. The CFR defines accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety.	http://www.phmsa.dot.gov/pipeline/library/data-stats

APPENDIX C – DASHBOARD EXAMPLES

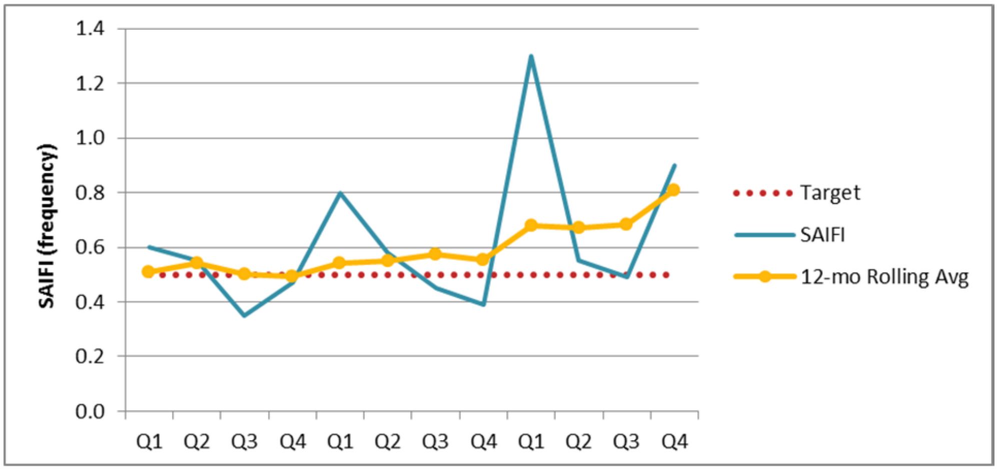
The following examples show how data dashboards can provide visual context for performance targets in terms of historical utility performance and trends. These examples are based on actual data (for unnamed utilities in western US states or on data for the entire United States) or they were fabricated for illustrative purposes.

Reliability

SAIDI is an indicator of sustained interruptions experienced by customers. SAIDI is defined as total minutes of sustained customer interruptions divided by total number of customers, over a period of time. This illustrative example shows a hypothetical utility's system wide SAIDI and 12 month rolling average over a three year period, along with its target.

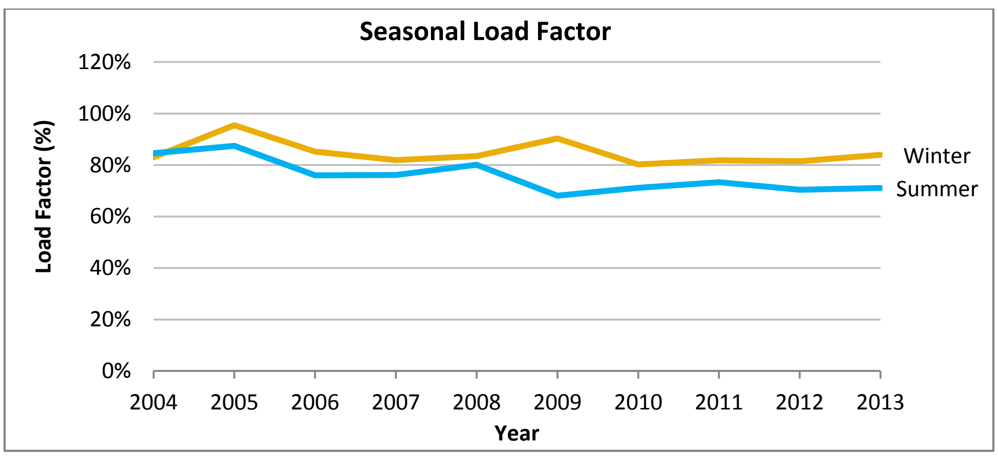


SAIFI is an indication of how many interruptions are experienced by customers over a period of time. SAIFI is defined as total number of sustained customer interruptions divided by total number of customers. This illustrative example shows a hypothetical utility's system wide SAIFI and 12 month rolling average over a three year period, and its performance target.



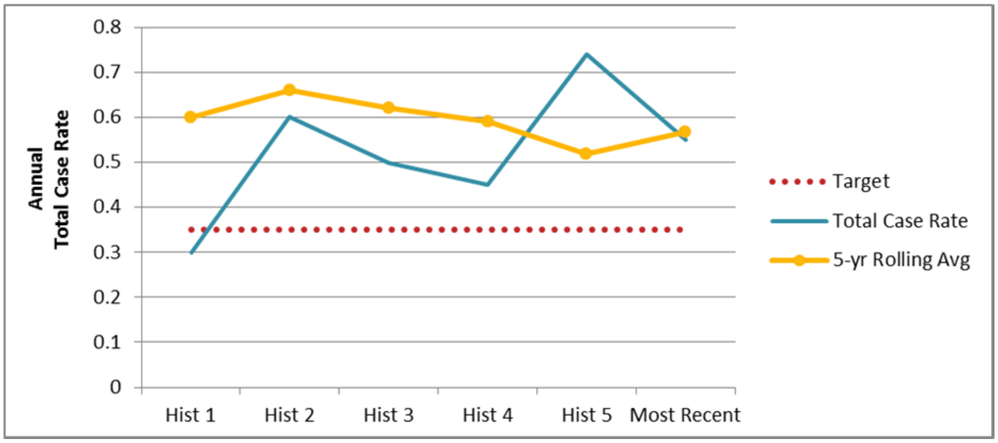
System Efficiency

As one metric for the efficient use of the electric system, load factor indicates the extent to which load occurs during peak periods. It is defined as the average load over a period of time divided by peak load. A dashboard can be used to show load factors for the entire system and for each customer sector over time. The example below shows the seasonal load factor for a western electric utility over ten years, obtained from FERC Form 1 data. Although FERC Form 1 provides energy and peak demand for the system as a whole, ideally load factors should be considered by consumer sector to allow for a targeted policy response.

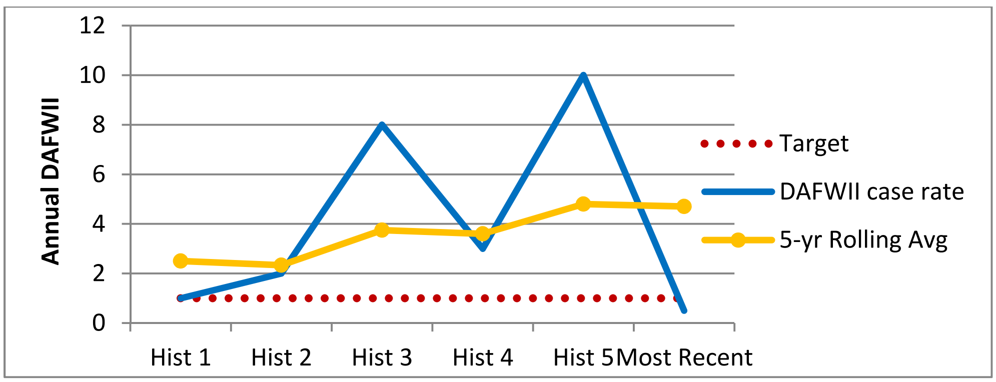


Safety

Employee safety can be measured using metrics. Standard metrics defined and reported by OSHA include work-related deaths, injuries, and illnesses (the Total Case Rate, or TCR); the Days Away from work, Restricted, or Transfer (DART) case rate; and the Days Away From Work (DAFWII) case rate. Because OSHA collects data from only a small fraction of companies, regulators should consider collecting data directly from utilities. Below is an illustrative example of a TCR for a hypothetical utility over a period of six years.

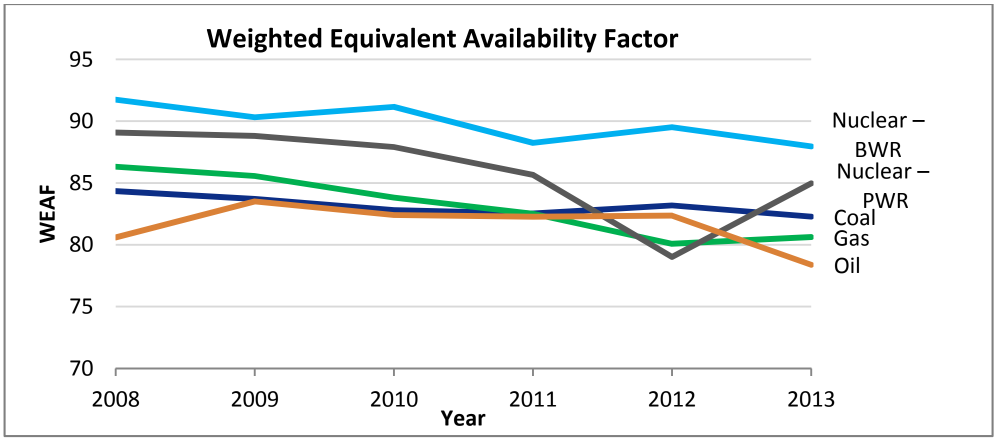


The following graph shows an illustrative example of a Days Away From Work (DAFWII) case rate over a period of six years for a hypothetical utility.

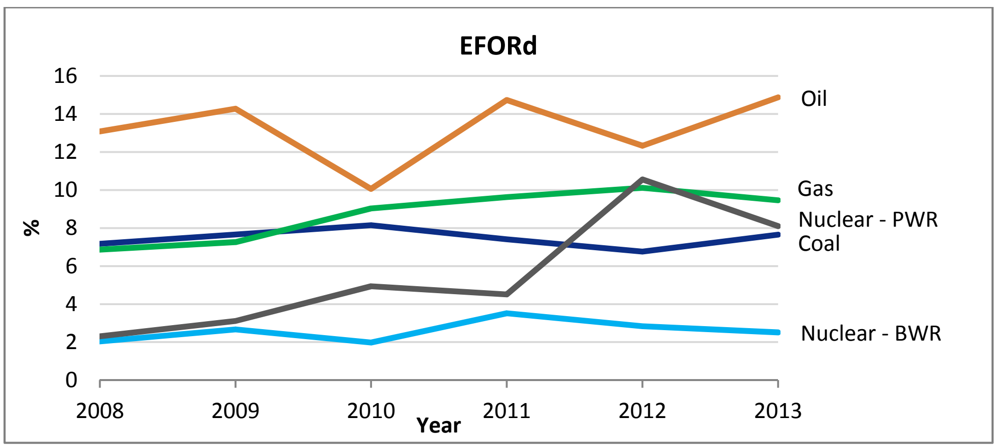


Power Plant Availability

Regulators often review the performance of individual power plants. However, regulators should consider the performance of the electric system as a whole, especially in the context of resource planning. The Weighted Equivalent Availability Factor (WEAF) is a metric indicating availability of supply side generation resources. Below is a graph showing the actual WEAF for the entire U.S. for six historical years, by fuel type.

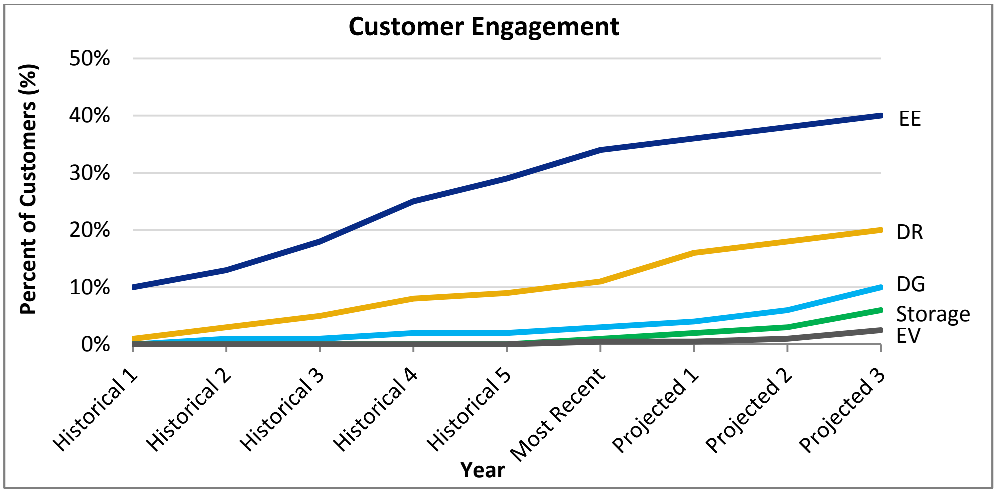


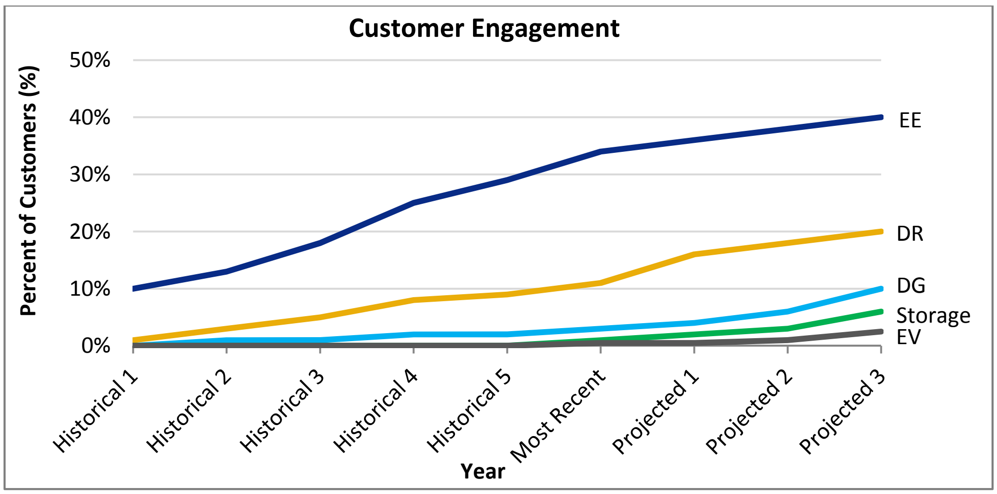
The Equivalent Forced Outage Rate Demand (EFORd) measures the probability that a unit (or group of units) will not meet demand periods for generating requirements because of forced outages or derates. Below, is a graph showing the actual EFORd by fuel type for the entire U.S. over six historical years.



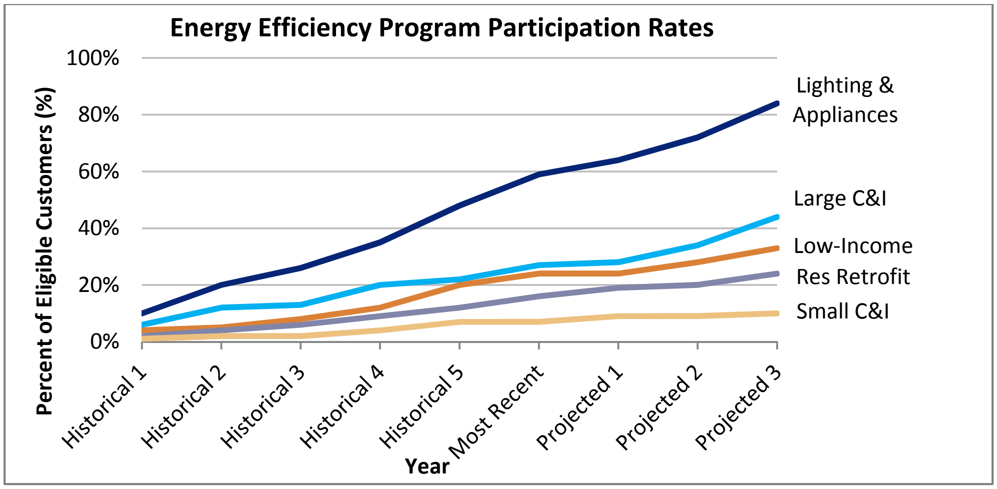
Customer Engagement

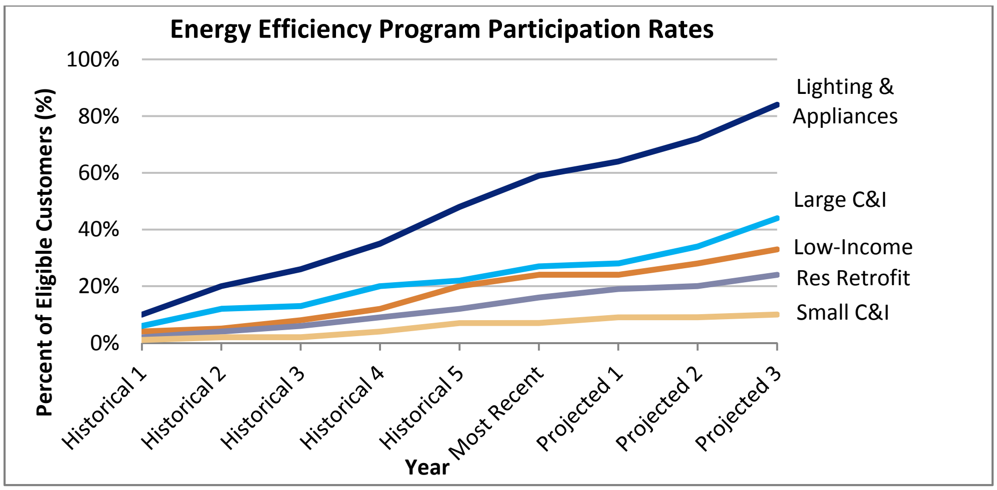
Customer engagement metrics indicate the extent to which customers are participating in demand-side programs or installing demand-side resources, which can reduce the need for new supply-side resources. The following graph shows historical and projected customer engagement for a hypothetical utility in five key areas: energy efficiency (EE), demand response (DR), distributed generation (DG), customer-sited energy storage, and electric vehicles (EV).





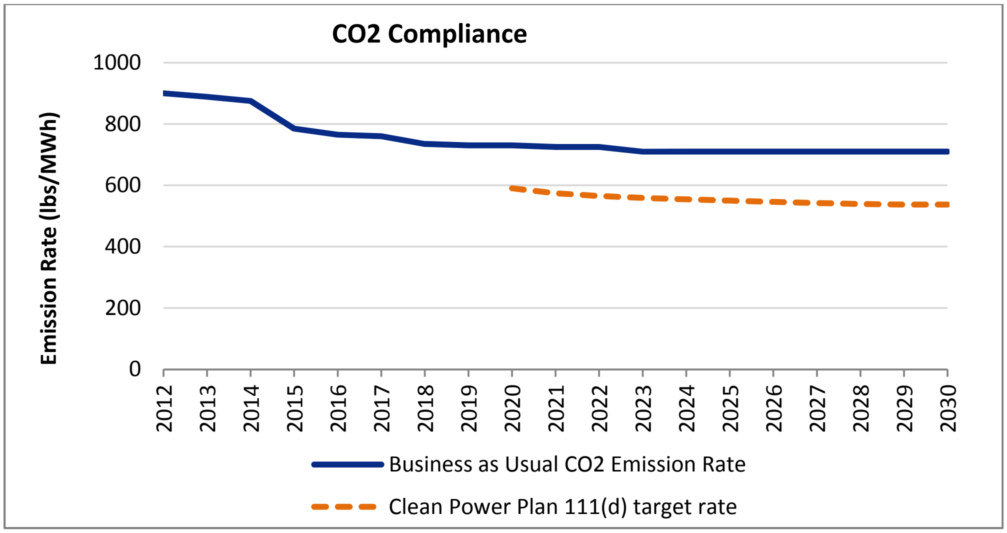
As an indication of which sectors are participating in energy efficiency programs, utilities and regulators may wish to examine participation in programs targeting specific customer segments, as a percentage of customers eligible for those programs. The following graph shows historical and projected participation rates for a hypothetical utility's lighting and appliances (for which data on participant customer types are rarely available), large commercial and industrial (C&I), low-income, residential (res) retrofit, and small C&I energy efficiency programs.





Environmental Goals

Environmental metrics indicate the extent to which the utility and its customers are reducing environmental impacts and can be particularly important with regard to ensuring that the state is on a path toward compliance with climate change regulations. Below is a graph showing the actual Clean Power Plan target CO2 rate for a western state, along with historical and hypothetical projected emissions rate under a business as usual scenario.



Below is an illustrative graph showing historical and projected fossil and renewable generation as a percent of total generation for a hypothetical utility.