Performance Based Regulation Plans

Goals, Incentives and Alignment

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December 6, 2017

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This report was prepared for DTE Energy. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of The Brattle Group for peer review.

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Executive Summary

DTE Energy retained The Brattle Group to review and analyze performance based regulatory (PBR) frameworks that have been applied to electric and natural gas distribution utilities in the United States as well as elsewhere in the world. DTE initiated Brattle's "benchmarking" study in order to inform its management team as well as to be responsive to recent legislation enacted in Michigan Public Act 341 of 2016 Section 6U (PA 341) which directed the Michigan Public Service Commission (MPSC or Commission), in collaboration with representatives of each customer class, utilities, and other interested parties, to study these frameworks.

Performance-based regulation (or performance-based ratemaking) has been used synonymously with incentive regulation (or incentive-based ratemaking, IBR), and generally refers to a regulatory framework that motivates utilities to improve their performance by enticing them with the opportunity to increase their earnings, more so than would be the case under more traditional cost-of-service regulation. There is not a bright line separating traditional cost of service ratemaking from PBR, as even traditional cost of service ratemaking provides a financial incentive to control costs via regulatory lags. However, PBR is generally differentiated by the methodical incorporation of incentives into the regulatory framework.

Our analysis has a relatively broad geographic scope. We surveyed the existence of selected elements of regulatory frameworks in place in most jurisdictions in the U.S., through a review of previously completed industry studies and surveys, Brattle research and analysis, and case study analysis for selected U.S. utilities. We also conducted case study analysis with regards to the regulatory frameworks applied to utilities in Great Britain (i.e., RIIO, as this framework is specifically singled out for study in the Michigan legislation), Canada and Australia.

The scope of our analysis also includes several incentive-oriented dimensions or PBR "elements" (including elements that some analysts may not consider to be PBR in nature). In practice, regulatory ratemaking frameworks are composed of combinations of elements offering different incentives or risk mitigation mechanisms. These include:

- Broad-based incentive frameworks focused on strengthening incentives to control costs – can also be defined as multi-year rate plans (MRP);
- Narrower incentives focused on maintaining and/or improving specific aspects of utility performance (e.g., service quality), typically through targeted performance incentive (TPIs) mechanisms; and

- Incentives to invest in the grid or risk mitigations mechanisms, such as capex riders/trackers.

We assigned regulatory frameworks in whole or in part into categories (e.g., price cap plans or formula rate plans) in order to facilitate the benchmarking analysis, following "labeling" conventions that have been commonly used by practitioners. However, it is important to note that such labels are not always consistently applied throughout industry articles and economic literature, and may not consistently represent the important features that distinguish one PBR plan from another.

Most of the regulatory frameworks that we considered to be PBR do not fit neatly into a "pure play" category (such as a "price cap" plan) but, instead, are composed of combinations of the above described incentive elements. Setting a moratorium on further rate cases for a pre-set period (which is the basis for an MRP), and/or defining a relatively long regulatory lag creates an incentive to control costs and tends to be the foundational elements of many PBR plans. This MRP aspect may be combined with targeted performance incentives and other regulatory mechanisms which provide supplemental incentives and/or mitigate risks associated with major capital programs or areas in which cost increases cannot reliably be foreseen and/or are not controllable by the utility.

TPIs focus on reaching specific outcomes. The incentives embedded in "traditional" TPIs (e.g., reliability and customer service) are typically more "stick than carrot" in that they are frequently asymmetrical downward; e.g., failure to meet service level targets will result in a loss of earnings. However some of the newer TPIs are designed to motivate utilities to shift behavior in ways that support new policy and less traditional goals (such as integration of distributed energy resources) and tend to be constructed in an asymmetrical upward fashion.

The more "ambitious" PBR frameworks have been applied outside of the U.S., such as in Great Britain, Australia and Canada. Great Britain's RIIO holds the highest profile position, which may explain why Michigan's PA 341 includes references to RIIO and totex as PBR options. "Totex" – a regulatory construct under which utilities earn returns on the total expenditure (i.e., capex plus opex) over the whole life of utility assets, rather than on capital expenditures alone – has received considerable attention as an element of PBR but, to our knowledge has not been implemented in the U.S. yet. Nonetheless, we expect to see totex, or variations upon it, to be seriously considered and applied in leading jurisdictions in the near future.

A logical first step in developing a regulatory framework for utilities in Michigan (and, for that matter, for utilities in general) involves specifying the issues of concern. Some of the issues and elements identified in Michigan's PA 341 can only be met through PBR elements while others can be met through other options (e.g., encouraging utilities to invest in projects with long pay-backs). The issues and elements cited in PA 341 and the associated regulatory options are summarized in the table below.

Elements Identified in PA 341 and Related PBR Mechanisms

Michigan Legislation	Related PBR Mechanisms
Multi-year periods; increase the length of time between rate cases	MRPs (price caps, revenue cap) Stair step adjustments, I – X
Encourage utilities to make investments that have extended payback periods	Riders/Trackers, Formula rates
Totex	Totex or variations thereon
Targeted performance areas (e.g., customer satisfaction, reliability)	PIMs
Profit sharing	ESMs, regulatory assets

Following from the PBR mechanisms included in the table, we note that:

- Increasing the time period between rate cases, which we found to be the foundation of broad-based incentive frameworks, can be implemented in many different ways (e.g., "features" of the framework include length of the time period between rate cases, expenditures to be included vs. excluded from the scope, and type of rate adjustment between rate cases).
- Encouraging (or "easing the way" for) utilities to invest in projects with long-term pay-backs (e.g., grid modernization) can be accomplished through capex riders/trackers (e.g., PSE&G) or formula rates (e.g., ComEd), either on a stand-alone basis or as part of an integrated PBR plan.
- Encouraging utilities to make spending decisions that minimize total costs (addressing any perceived bias towards capital based solutions) can be accomplished through various adjustments to the ratemaking process. However, the totex approach is the most direct.
- Holding utilities accountable to performance standards for specific elements can be accomplished with TPIs. Some capex riders/trackers or formula rates are also tied to performance requirements. (We, and others, do not categorize these performance requirements as TPIs.) As is the case with capex riders/trackers and formula rates, TPIs can also provide an important dimension of an integrated PBR framework.
- Profit sharing can be accomplished through specific earnings sharing mechanisms, however it is also inherent in PBR plans through the resetting of rates at the end of the MRP. That is, in frameworks with no earnings sharing mechanism, if a utility "saves" a

dollar (i.e., reduces its revenue requirement through improving its operating efficiencies), rates are eventually reset to reflect the improved cost structure.

Thus, designers of PBR frameworks should focus on four key dimensions:

- The term of the plan, meaning the period of time between one rate case and the next. This is a crucial feature because it largely determines the strength of the incentive to control costs. The longer the time between rate cases, the greater the opportunities for the utility to realize additional earnings by performing above expectations (and also the greater the chance for losses if the utility performs below expectations). We find that PBR plans range in length from three to eight years, with three or four being common in the U.S.
- The scope of the plan, meaning what activities and associated costs are included within the revenue determined at the outset in the rate case, and what is "outside." Activities outside the PBR plan are funded instead by riders/trackers or other mechanisms which update revenue according to how recorded costs change during the plan term. Activities within the scope of the plan are may be adjusted during the term (e.g., following an I – X indexation) but are not updated to reflect changes in recorded or forecasted costs until the end of the term. Activities within the scope of the plan are under the strengthened incentives of PBR while activities outside the plan are not. Some PBR plans are comprehensive, covering all utility activities and costs, while others may focus on specific activities or categories of cost (e.g., O&M only).
- Revenue or rate adjustment during the plan term: some plans have no adjustment (i.e., rate freeze), while others may adjust for changes in inflation or may have pre-determined "stair-step" changes each year. Periodic (typically annual) rate/revenue adjustments enable better alignment with costs expected at the outset; this revenue adjustment may allow for a longer plan term, and therefore may result in stronger incentives. The method of adjusting revenue itself, however, has no impact on incentives. Only if changes in recorded costs were to influence revenue adjustments before the end of the plan term would incentives be weakened (as in a rider/tracker mechanism).
- Outputs of various kinds can be measured and can drive additional financial rewards or penalties as part of a PBR plan. Such TPIs have traditionally been used to target distribution network reliability and customer service (call center response times). Other outputs can also be measured, such as quantity of renewable generation connected to the distribution network. Emerging TPIs are being developed to encourage utilities to contribute to achieving various policy goals such as renewables penetration, distributed energy resources, and energy efficiency.

Our benchmarking analysis indicates that, in practice, PBR plans implemented for different utilities/jurisdictions reflect the policy priorities of a jurisdiction, the challenges faced, and the specific circumstances of the utility or utilities included in the plan– and thus frequently defy fitting into pre-defined labels or categories. Accordingly, regulators can introduce singly focused areas of incentives (e.g., cost controls via MRPs) or balance a range of goals by implementing multiple incentive related elements (e.g., covering cost controls, specific areas of outcome-based performance, as well as risk mitigation mechanisms). The specification of the overall PBR plan depends on the challenges faced and the priority of objectives and policy goals.

I. Introduction

DTE Energy asked The Brattle Group to review and analyze the range of performance-based regulation (PBR) frameworks and approaches that are applied to electricity and natural gas utilities in the U.S. and abroad. Our understanding is that, in addition to informing DTE management, our report will provide context to the dialogue concerning the future of regulatory frameworks for energy utilities that is currently taking place in Michigan.

Our report is designed to support the collaborative process by providing context as to how PBR has been applied (in the U.S. and elsewhere). We have reviewed specific PBR plans implemented in the U.S. and elsewhere in the world as well as a range of reports, studies and articles concerning PBR frameworks. Necessarily, as a means to benchmark the various approaches taken, we have assigned specific elements of PBR frameworks or, in some cases, plans in their entirety, into categories (e.g., price cap plans or formula rate plans). That is, we "label" PBR plans[1] and approaches as they are commonly discussed by practitioners. However, it is important to note that such labels are not always consistently applied throughout industry articles and economic literature, and may not consistently represent the important features that distinguish one PBR plan from another.

We highlight what we consider the most important findings concerning PBR frameworks in the conclusion of our report:

- The combination of design features and supplemental incentives and/or cost recovery assurances defines the balance of risk and reward faced by a utility; and,
- This combination also defines the degree to which a regulatory approach should be considered PBR or incentive regulation, more so than specific labeling conventions.

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1 A "plan" is the ensemble of rules that defines a utility's ratemaking process, i.e., the process through which utility revenues and rates are set.

A. PBR IN MICHIGAN

Utilities in Michigan are largely regulated under a traditional cost-of-service framework.[2] However, in late 2016, the State's legislature and Governor approved legislation that directed the Michigan Public Service Commission to "commence a study in collaboration with representatives of each customer class, utilities, and other interested parties, under which a utility's authorized rate of return would depend on the utility achieving targeted policy outcomes."[3] The legislation further specified that the Commission's study should include:

- PBR systems that have been implemented in other states or countries, including, but not limited to, the RIIO (revenue = incentives + innovation + outputs) model utilized in the United Kingdom.
- Methods for estimating the revenue needed by a utility during a multi-year pricing period, using total expenditures (totex).
- Methods to increase the length of time between rate cases, to encourage utilities to make investments that have extended payback periods.
- Options for establishing incentives and penalties for targeted performance areas (e.g., customer satisfaction, safety, reliability, environmental impact, and social obligations).
- Profit-sharing provisions among consumers and utility shareholders, to mitigate downside risk.

B. PBR: DEFINITION AND SCOPE

Performance-based regulation (or performance-based ratemaking, PBR) has been used synonymously with incentive regulation (or incentive-based ratemaking, IBR), and generally refers to a regulatory framework that motivates utilities to improve their performance by enticing them with the opportunity to increase their earnings, more so than would be the case under more traditional cost-of-service regulation. Typically, the means through which utilities improve performance is through implementing operational improvements and cost efficiencies (with respect to both operating and capital expenditures). As costs are better controlled, the utility will earn a greater return for a given amount of approved revenue. The ability to collect

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2 The regulatory framework also includes several areas of specific incentives, for example incentives for complying with the renewable energy standard (RES) and Energy Optimization (EO) enabled by Public Act 295 (See "Cost of Service Ratemaking," Michigan Public Service Commission Department of Licensing and Regulatory Affairs, March 2014).

3 Public Act 341 of 2016 (4.20.2017).

the approved revenue independent (until the next rate case) of success or otherwise in controlling costs is what provides the utility with a financial incentive to improve its performance. However, as will be discussed below, PBR plans may also offer incentives that are based on outcomes not associated with costs, and may, for example, be designed to promote (or at least allow) utility investment in large projects.

There is not a bright line separating traditional cost of service (C-o-S) ratemaking from PBR, as pointed out by some scholars: Alfred Kahn is reputed to have said that "All regulation is incentive regulation," while Jean-Jacques Laffont and Jean Tirole have noted that "The contrast [between traditional rate of return regulation and PBR] is mostly one of emphasis."[4] More specifically, traditional C-o-S ratemaking provides a financial incentive to control costs[5] because rates (or revenues)[6] are determined in the rate case and are not otherwise adjusted until the next rate case. The incentive increases still further under arrangements with a prescribed schedule (e.g., every three years), such as California's general rate case (GRC) format.[7]

Interest in PBR is not entirely new, but has received additional attention as the utility industry continues to experience disruption. Specifically, sales growth has flattened or declined for many utilities, which has a substantial impact on the ratemaking process. Historically, growing sales (in terms of customers and usage per customer) typically covered rising costs and supported investment even without increasing rates, for example due to economies of scale. However, more recently, growth has stopped or has even reversed, which has necessitated more frequent rate cases. In addition to being administratively costly, frequent rate recalibration limits the incentive to control costs and improve efficiency because the utility foresees that a successful effort to

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4 Laffont, Jean-Jacques and Jean Tirole. *A Theory of Incentives in Procurement and Regulation*. (Cambridge: MIT Press, 1993.)

5 In this report, we use "control costs" as shorthand for efforts on the part of utility management to reduce costs, relative to where they would otherwise have been, by finding ways of operating more efficiently.

6 We discuss below examples of PBR plans with fixed *rates* and other examples with fixed *revenues* between rate cases. The latter incorporate a mechanism to make revenues independent of billing determinants (e.g., through a form of sales decoupling). Except where we seek to draw this distinction, we refer to rates and revenues interchangeably.

7 Incentives are not necessarily open-ended, however. Typically, rates are reset or "rebased" in the next rate case.

control costs will quickly be passed on to customers as the authorized revenue requirement is reset in the next rate case.

Also, additional industry disruption has been brought about by the introduction of distributed energy resources (DERs) and policy goals concerning renewable integration and emissions reduction. Some analysts have voiced that, "cost of service regulation stifles utility innovation and causes utility managers to be more responsive to regulators than to customers."[8] Thus, utilities and regulators have proposed and/or implemented enhancements to traditional C-o-S or, in some cases, modified their regulatory frameworks to be based on more pronounced incentive structures.

Regulatory plans typically encompass various combinations of elements, which lessens the informational context of categorizations and counts of types of PBR. For example, a utility may be regulated under a multi-year rate plan (MRP) with an annual adjustment mechanism, and also be subject to various targeted performance incentives (e.g., system reliability and/or customer service). On top of that, the utility may receive additional revenues from riders/trackers that address specific capital expenditures (e.g., associated with a specific reliability or resilience program). To complicate matters further, if asked, the regulator may not consider the regulatory framework described above to be PBR—even though some independent surveys may refer to the approach as PBR.

With this in mind, we have adopted the following categories and provide further details on each of these throughout the remainder of our report, with the important caveat that such labeling may represent distinctions without real differences.

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[8] "Performance-Based Regulation for Distribution Utilities," The Regulatory Assistance Project, December 2002, p. 2.

Table 1: Categorization of PBR Frameworks for Use in Benchmarking Analysis

PBR Category	"Label"	Incentive Area
Broad-based Incentive Frameworks	MRP/ARM Price Cap Revenue Cap RIIO	Cost Control
Narrower Incentive Mechanisms (Targeted Performance Incentives)	"Traditional" TPIs "Emerging" TPIs	Service Quality Improvement
Supplemental Incentives (Risk Reduction)	Formula Rates Capex Riders/Trackers	Investment (e.g., Grid Modernization)

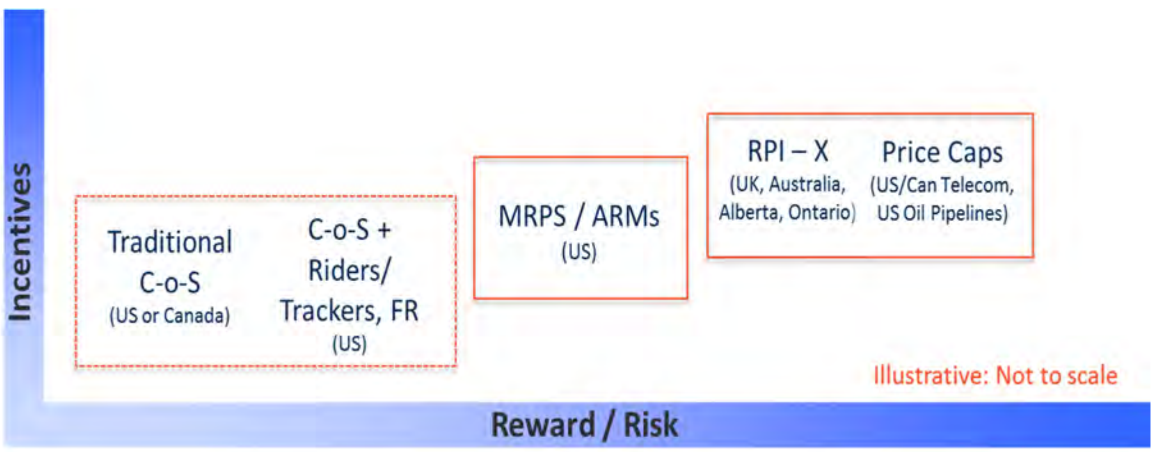
In our nomenclature, broad-based incentive frameworks are designed to address overall utility performance in controlling costs. Under these plans, utilities can be provided substantial leeway concerning their operations in between rate cases, which occur several years apart (typically from three years to as many as eight). Accordingly, if a utility is able to improve its cost efficiency (without compromising its basic service obligations), it is able to keep the additional profits generated (or some of the profits, if an earnings sharing mechanism is in place). Narrower incentive mechanisms are much more targeted and involve specific performance areas. For example, utilities may face financial penalties for failing to meet an agreed upon reliability target.

We include the supplemental incentive category in order to be complete in our review. Such arrangements sometimes fall outside of surveys of PBR. Riders/trackers and formula rates typically involve periodically resetting or adjusting utility rates or adding a line item to customers' bills to ensure that the utility recovers the costs associated with an investment or other cost area outside of the rate case process. This approach provides the utility with an incentive to incur expenditures that it may otherwise deem too risky (and not make). Also, by removing one or more categories of investment from the general ratemaking framework, the rider/tracker may permit a longer period between rate cases than would otherwise be possible, thereby strengthening incentives on the other categories of expenditure. Thus, we include riders/trackers in our benchmarking analysis because they provide incentives for utilities to invest in infrastructure via a risk mitigation mechanism.

C. Risk and Reward

Regulatory frameworks can be viewed in terms of their profile for risk and reward. That is, PBR type plans are structured so that utilities are provided an incentive to improve performance or realize outcomes. Providing a stronger incentive implies greater financial uncertainty in outcomes (for example, as the period between rate cases is lengthened, it is more likely that achieved returns will end up above or below the authorized level). However, the possibility for a loss also comes with the potential for reward—overall financial outcomes are more uncertain (i.e., riskier). The details of the specific components of a regulatory framework determine the level of risk and reward potential. We adopted a simple depiction of the range of PBR plan types and the associated levels of risk and reward in Figure 1 below.

Figure 1: PBR Frameworks on a Risk and Reward Scale



Source: Brattle representation of plan categories. Distance from axes is illustrative and does not represent a precise level of incentives and/or risk/reward associated with regulatory plan categories.

Figure 1 depicts a diagonal progression of PBR plans, starting with modest enhancements to traditional C-o-S regulation (located towards the bottom left of the diagram) and moving toward plans that are more widely recognized as PBR with relatively stronger incentives and greater degrees of risk/reward. For example:

- "Fairly" designed price and revenue cap plans provide for higher risk/reward levels and strong incentives to control costs. However, these plans, by themselves do not necessarily provide incentives to invest in grid infrastructure (because of the regulatory lag that forces the utility to "wait" until the next rate case, unless specified otherwise).
- Traditional ratemaking combined with a capital expenditure (capex) rider/tracker substantially insulates a utility from risk, and thus can be depicted as providing limited risk/reward. Such an approach provides a mechanism to recover expenditures in between

rate cases, reduces risk, and thus provides an incentive for utilities to invest in major projects.

We describe the various types of PBR plans implemented in the U.S. and around the world in the next sections of this report.

Throughout the report, “broad-based” incentive frameworks refer to plans that provide a utility with opportunities to improve its earnings overall via cost control and improvements in efficiency; they tend not to prescribe specific efforts or areas (i.e., the utility can use its discretion and managerial acumen to determine how to achieve improved efficiencies). We refer to financial incentives for achieving targeted outputs as “targeted performance incentives”. Finally, we refer to the large scope of riders/trackers as risk reduction or supplemental incentives.

D. Report Organization

We discuss the various applications of broad-based incentive frameworks in Section II. These plans are typically based on MRPs and provide incentives to utilities to control costs. We turn to targeted performance incentives (TPIs) in Section III. TPIs can also be regarded as “performance” based regulation as they address specific areas of utility performance (mainly reliability and customer service). We discuss regulatory frameworks designed to reduce investment risk in Section IV, Supplemental Incentives.

However, as we discussed at the outset, in practice, PBR plans frequently involve combinations of the above referenced elements, specifically designed to address policy goals. We provide case studies of specific plans applied in the U.S. as well as in Great Britain, Canada and Australia in Section V, Integrated PBR Frameworks. We then provide a brief overview of differences across states with respect to regulatory authority to deviate from traditional C-o-S regulation in Section VI. Finally, we summarize our key findings and conclusions in Section VII.

II. Broad-based Incentive Framework

A. Incentive to Control Costs

A broad-based incentive framework is an expansion of the opportunities and incentives embedded in the regulatory lag[9] associated with traditional C-o-S regulation.[10] Under a broad-based incentive framework, regulators and utilities typically set rates (or revenues) on a traditional C-o-S basis at the outset of the plan and then agree to not revisit rates/revenues via a formal rate case for a specified period of time. That is, there is a high degree of certainty that the utility can realize and retain improved earnings over the course of the plan without risk of "claw back" in a regulatory review. Equally, if the utility is unsuccessful in controlling costs, it is at the risk of earnings being below the authorized level, without the ability to request a retrospective true up later.

Broad-based incentive frameworks are also labeled "multi-year rate plans" (MRPs), which highlights the fact that a rate case is followed by a moratorium on further rate cases for a pre-set period. This period is typically defined between three and eight years.[11] In between rate cases, rates may be fixed, or may be adjusted at pre-determined intervals to account for the impact, for example, of expected inflation or productivity gains. The mechanism for adjusting rates between rate cases is clearly defined at the outset in the rate case. It is crucial for rate adjustments to be defined at the outset to ensure a high degree of certainty of how the adjustments will be subsequently made. The utility is then clear about the extent to which a successful effort to control costs will result in increased earnings. Rider/trackers, true-ups, deferral accounts and similar mechanisms are often used to address the need for additional expenditures or investments separately from rate cases to reduce the utility's exposure in between rate cases.

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9 Regulatory lag refers to the time between two rate cases.

10 We use the label "traditional cost of service regulation" to refer to a ratemaking mechanism in which rates are set according to a utility's expenditures and cost of capital and can be re-set as often as the utility, regulator or other intervener such as consumer groups claims (or formulates a suspicion) that the rate of return actually earned is lower (or greater) than is allowed.

11 For example, as we discuss in detail below, California utilities typically have three years between rate cases whereas utilities in Great Britain have eight years between rate cases under the RIIO framework. A typical period is five years.

The incentive structure for broad-based incentive frameworks is based on a utility having the opportunity to realize earnings that are either above or below the authorized level, depending on its success in controlling costs during the period in between rate cases. Such incentives are also built into traditional C-o-S regulation: utilities can retain earnings above authorized levels in between rate cases. However, the fundamental feature of broad-based incentive frameworks that distinguishes them from more traditional C-o-S approaches to rate regulation is that a utility's revenues under broad-based incentive frameworks are less strongly correlated with the utility's recorded costs than they would be under a traditional C-o-S approach. Typically, a traditional C-o-S proceeding with a forward test year will examine a forecast of test year costs as well as recorded costs for the most recent year available. As a result, the level of revenues that is approved for the test year can take into account changes in recorded costs up to that most recent year available. However, once rates are set, subsequent changes in recorded costs do not influence rates (except via the operation of rider/trackers, true-ups or similar mechanisms). A rate case can be requested if the earned rate of return is lower (or greater) than is allowed. In a broad-based incentive framework, changes in recorded costs do not influence changes in rates during the term of the plan (other than through rider/trackers and other similar mechanisms). As a result, if the utility is successful in efforts to control costs, the financial benefit (relative to pre-determined adjustment in between rate cases) accrues initially to the utility and its investors. This provides a financial incentive to the utility to search for and implement measures that could reduce costs.

In the following sections, we describe the key features of broad-based incentive frameworks (or MRPs) some of which include pre-determined annual adjustment mechanisms. We then turn to two specific forms of MRPs—"I – X" price and revenue caps—which have a highly specified formulaic approach to adjust rates or revenues between rate cases.

B. Features of a Broad-based Incentive Framework

The defining characteristics of broad-based incentive frameworks balance incentives, risk and rewards through the specification of design elements. These elements include:

- **Plan term**, or the amount of time between two rate cases. Longer terms provide greater incentives to control costs, and therefore greater opportunities to realize additional earnings if the utility is able to perform effectively. Conversely, it also permits the chance that the utility will realize earnings below its authorized levels if its performance falls below expectations.

- **Plan scope**, or the specific costs that are specified as inside (and outside) of the plan. Some costs are dealt with under separate arrangements, such as through riders/trackers, deferral accounts, and other true-up mechanisms. The rest of the utility's costs (both operations and maintenance and capital expenditures) are covered in the rate case process and thus are within the scope of the MRP. Generally, the broader the scope (i.e., fewer costs that are treated separately through riders/trackers or the like), the more actual rates are disconnected from incurred costs (in between rate cases). This leads to a higher level of incentive for utilities to control costs and a higher reward / risk profile than would be the case if a significant portion of utility costs were assured recovery via riders/trackers or similar recovery mechanisms.
- **Revenue requirement and rate setting**, or the method used to set rates going in to an MRP. Forward looking revenue requirements can be estimated using a historical trend, an average industry-wide trend, or a forecast. Using a historical trend or average implicitly assumes that the costs of an efficient utility changes over time in way that can be captured with past patterns and are relatively easy to predict, in contrast to forecasted costs, which recognizes that efficient costs may change over time in a more complex fashion.
- **Rate adjustments between rate cases:**
  - **Attrition Relief Mechanism (ARM)**,[12] or a mechanism to adjust rates in between rate cases. Rates/revenues can be kept constant ("rate freeze"), can be indexed to a form of "I-X" (inflation minus offset), or can evolve based on a pre-determined escalation ("stair-step trajectory"). The strength of incentives will remain high if the mechanism to adjust rates or revenues between rate cases is independent of changes in recorded costs as they evolve during the plan term.[13] The strength of incentives can be influenced by the term of the plan, with longer terms providing stronger incentives.
  - **Adjustment of rates vs. revenues**. When rates are adjusted between rate cases, ARMs can be applied to rates or revenue requirements. Typically, "I-X" indexing is applied to either. When ARMs are applied to revenue requirements (e.g., revenue cap), it creates a decrease in volume risk as revenue requirements become "decoupled" from the throughput. When ARMs are applied to rates, the volume assumption used to

12 ARMs have been defined as "a common component of multi-year rate plans that automatically adjusts rates or revenues between rate cases to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable cost drivers such as inflation and customer growth." See Mark Newton Lowry and Tim Wolf, "Performance-Based Regulation in a High Distributed Energy Resources Future," Lawrence Berkeley National Laboratory's Future Electric Utility Regulation Series, January 2016.

13 In contrast, a "formula rate" mechanism, discussed further below, explicitly adjusts revenues in light of recorded costs and rate base and therefore does change (weaken) incentives.

create rates remains the one decided at the outset in the rate case, which results in a risk of not recovering the necessary revenue if volume of sales decreases.

- **Supplements and/or Adjuncts**, refers to other elements of an overall regulatory framework, such as TPIs, formula rate treatments and/or riders/trackers. These need to be factored in to the design and effectiveness of a PBR because they can provide additional incentives (e.g., TPIs) or may mitigate risk (e.g., capex riders/trackers). These supplemental elements are further discussed in sections III and IV.

There may also be other relevant factors to consider as well, notably off-ramp options and triggers to initiate rate cases before the term of the plan is completed (such as via indicators that return on equity (ROE) is significantly outside of the expected range).[14]

The combination of these elements and other idiosyncratic features in existing broad-based incentive frameworks can differ significantly from one plan to the other. Table 2 below shows the different elements of a subset of frameworks throughout the world.

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14 For example, the current rate plan for the Alberta distribution utilities (for the 2013-2017 term) includes a provision to reopen and review a utility's PBR plan when its earned, weather-normalized ROE is 500 basis points above or below the approved ROE in a single year or 300 basis points above or below the approved ROE for two consecutive years. Alberta Utilities Commission (AUC) Decision 2012-237, "Rate Regulation Initiative – Distribution Performance-Based Regulation," September 12, 2012, p. 161 ¶ 737.

Table 2: Key Attributes of Representative Broad-based Incentive Frameworks

	Utility	State, Country	Business Segment	Plan Term (years)	Incremental Capex Excluded from the Scope	Setting Revenue Req. at the Outset	Adjustment Between Rate Cases
[1]	**ATCO Electric**	Alberta, Canada	Elec distrib	5	Some	Historical trend	I-X price cap
[1]	**ATCO Gas**	Alberta, Canada	Gas distrib	5	Some	Historical trend	I-X revenue per customer cap
	PG&E	CA, US	Elec & gas distrib	3	None	Mix of forecast and historical trend	Stair-step
	Con Edison	NY, US	Elec & gas distrib	3	Some	Multi-year forecast	Stair-step
[2]	**FPL**	FL, US	Fully integrated elec revenue with FAC	4	Some	Multi-year forecast	Stair-step
	Ausgrid	NSW, Australia	Elec distrib	5	Some	Multi-year forecast wih "smoothing"	I-X revenue cap
	NPg (RIIO)	England, UK	Elec distrib	8	Some	Multi-year forecast wih "smoothing"	I-X revenue cap
	NGN (RIIO)	England, UK	Gas distrib	8	Some	Multi-year forecast wih "smoothing"	I-X revenue cap
[2]	**Xcel Energy, NSP**	MN, US	Fully integrated elec revenue with FAC	4	None	Multi-year forecast	Stair-step

Sources and Notes: See Case Studies in **Appendix B**.

The column "Business Segment" describes the utility's business segment at stake in the plan described in the above table. Some utilities' activities may only include that specific segment (e.g. ATCO is a distribution utility), while other utilities may have a broader range of activities then the business segment we are focusing on in here (e.g., PG&E is a vertically integrated utility but defines a revenue requirement specific to distribution, which is what we choose to discuss in this table).

[1] The framework described in this table will be applicable starting 2018.

[2] FAC refers to fuel adjustment clause.

As shown in Table 2, broad-based incentive frameworks can be designed in very different ways. As explained above, a longer term provides more incentive to control costs (and possibilities to earn rewards/penalties). However, limiting the scope of the costs "at risk" in between two rate cases (i.e., costs included in the scope of the plan and for which rates may only be reviewed in the next rate case) mitigates the risk borne by utilities. For instance, the RIIO framework sets a fairly long term (eight years) but has various mechanisms to address uncertainty and costs outside the utility's control. On the other hand, the MRPs for the U.S. utilities included in Table 2 (i.e., Pacific Gas & Electric Company (PG&E), Consolidated Edison (Con Edison), and Florida Power & Light (FPL) and Xcel Energy's Northern States Power (NSP) in Minnesota have a shorter term (three to five years), but tend to have fewer additional revenue adjustment mechanisms additional to the MRP.

Another important dimension is whether rates are mostly set on historical trends or if actual cost forecast is taken into account. Most of the U.S. stair-step trajectory mechanisms cited above use cost forecasts to define the escalation of rates between rate cases. Among the utilities with "I-X" adjustments, some utilities define rates for the first year of the term and then apply the "I-X" indexing to define rates for the following years of the term, e.g., ATCO utilities, while others define cost forecasts for the entire term at the outset and apply a "smoothing" mechanism to define the rates for the first year, such as Australia and U.K. utilities.

Among the utilities using cost forecasts to determine the "stair-step" escalation of rates at the outset, some utilities may use detailed forecasts for each year of the term—such as Con Edison and PG&E to some extent—while others, such as FPL, use detailed forecasts for the first couple of years of the term but only take into account some limited changes to define rates for the rest of the term (e.g., in FPL's latest rate case, the rate escalation for the last two years are based on one major change in capex).

C. RATE ADJUSTMENT BETWEEN RATE CASES

As mentioned in the prior section, some frameworks adjust rates between rate cases and use various mechanisms to do so.

According to recent studies concerning PBR in the U.S., MRPs (or broad-based incentive frameworks) are currently being applied in 28 states covering 62 utilities.[15] (A list of plans, states and affected utilities is included as **Appendix A-1**, Survey of Multi-year Rate Plans.)

MRPs can be further broken-down into two forms:

- Frameworks with a "rate freeze" under which rates are unchanged during the term of the plan; the utility's revenue will then depend only on the evolution in billing determinants.
- Frameworks that allow for periodic adjustments of rates or revenues via some type of pre-determined ARM.

15 "Rate Freezes: Their Historical Context and Prevalence Today," SNL Regulatory Research Associates, August 2016; and Mark Newton Lowry et al., "Alternative Regulation for Emerging Utility Challenges: 2015 Update," Pacific Economics Group for the Edison Electric Institute (EEI), November 11, 2015." (EEI Alternative Regulation, 2015).

Of the above referenced 28 states, 11 have incorporated ARMs into their plans (covering 28 utilities); while the remaining 17 states have a plan involving rate freezes.

Two categories of ARMs can be defined:[16]

- A "stair-step trajectory" consists of an escalation of revenues decided for each year of the term at the outset in the rate case. The escalation is typically defined on the basis of a forecast of how revenue requirement is expected to change over time. This approach can also be defined as a "multiple forward test year" approach.
- An indexing (or "I–X") mechanism allows for rates or revenues to be adjusted each year using actual inflation (I) less an offset (X). We use the label "price cap" and "revenue cap" to refer to the mechanisms adjusting by I-X rates and revenue requirements respectively. This is discussed further in the price cap and revenue cap section.

Stair-step trajectory ARMs are widely spread in the U.S. today. For example, PG&E, Con Edison, Xcel Energy and FPL are all regulated under a broad-based incentive framework that includes a stair-step trajectory adjustment mechanism. As discussed above, PG&E has a three-year term and pre-determines the escalation of its distribution revenue requirement for both gas and electricity on the basis of a combination of forecasting and historical trends at the outset of the rate case. Con Edison also has a three-year long plan for both gas and electricity distribution, where the escalation between two rate cases is calculated based on company forecasts of sales, property taxes, depreciation, plant in service, and other miscellaneous expenses.

Both Xcel Energy's NSP in Minnesota and FPL have four-year MRPs with a stair-step trajectory ARM applied to their vertically-integrated electricity revenue requirements, but excluding costs for power from the plan scope thanks to a fuel adjustment clause (FAC).

Based on our review, there are no applications of MRPs with I-X currently in place in the U.S., however, as noted below, several I-X plans were in place during the 1980s and 1990s.

D. Associated Provisions

Regulatory frameworks based on MRPs typically include safety net and/or off-ramp provisions in order to mitigate risk to the affected utilities as well as ratepayers. Utilities would be hesitant to agree to an open-ended multi-year commitment to rate levels because unforeseen circumstances

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16 The categories of ARMs were dubbed by EEI, see EEI Alternative Regulation, 2015.

may cause their earnings to fall significantly below authorized levels. Similarly, Commission Staff as well as consumer advocates would be unlikely to accept conditions under which a utility had the opportunity to earn returns well in excess of authorized levels.

- Earnings sharing mechanisms (ESMs) refer to provisions under which 1) regulators review the utility's return on equity during interim periods of the MRP, and 2) earnings above specified levels are shared with customers and earnings that fall below specified levels may be compensated in part by customers. ESMs thus have a moderating effect on the level of reward and risk included in the MRP incentive structure. Typically, no adjustment (or sharing) is made when utility ROEs fall within a specified range (i.e., a deadband centered on the authorized ROE). Sharing by the utility with customers (or charges by the utility to customers) are triggered when earnings fall outside of the pre-specified range.

  A recent survey indicated that 11 of the 15 states (included in the survey) which have MRPs, also have ESM provisions.[17] Of these, 9 include provisions for sharing earnings in excess of the authorized level (i.e., above the deadband), but do not have provisions in place for the "sharing" required to return the utility to the authorized level when actual returns fall below the deadband. That is, most of the ESMs are asymmetrical; utilities are entitled to retain a portion, but not all, of earnings realized that are in excess of allowed ROE levels, but are solely accountable when earnings fall below authorized levels.

- Rebasing refers to the provision for resetting rates at the conclusion of the MRP (i.e., setting "going-in rates" for the start of a new MRP plan). During the course of an MRP, rates are either frozen or adjusted based on a prescribed rate adjustment mechanism; they do not depend on changes in a utility's costs (either historic or forecasted). Rebasing involves calculating rates based on utility costs.

  During the term of the MRP, changes in recorded costs do not influence changes in rates, and utilities realize all or part of the financial benefits resulting from successful efforts to control costs. However, this benefit does not last forever; these benefits are transferred (in whole or part) to ratepayers when rates are rebased.

- An off-ramp refers to the provisions included in the MRP that allow for a broader review of the plan (sometimes referred as a "re-opener") or for termination of the plan entirely. The most common specified trigger for review or termination concerns returns falling below authorized levels. For example, the MRP applied to FortisBC includes a provision for review when post-sharing returns are either 200 basis points above or below the

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17 See EEI Alternative Regulation, 2015. Note that the states included in the EEI survey are a subset of the states with MRPs included in Appendix A-1.

authorized ROE.[18] However, re-opening and off-ramp provisions can be general and unspecified, in recognition that unforeseen factors (e.g., changes in tax laws or interest rates) may necessitate review, plan changes and/or termination of a plan. For example, rather than trying to identify the specific conditions under which MRPs could be re-opened, the Alberta Utilities Commission concluded that "any party…will be permitted to bring an application to re-open and review a PBR plan, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan."[19]

E. PRICE CAPS AND REVENUE CAPS

Under "I-X" price cap and revenue cap plans, "going-in" rates are set on the basis of a traditional C-o-S and are not subject to change until the next rate case other than through an I-X adjustment (and through riders/trackers and similar mechanisms). A new rate case, and the resulting rate adjustments, takes place at the end of the term or "stay out" period.

The annual adjustment mechanisms for price and revenue cap plans are specified as follows:

Price Cap: $P_y = P_{y-1} \text{ x } (1 + I_y - X)$

Revenue Cap: $R_y = R_{y-1} \text{ x } (1 + I_y - X)$

Where, P_y represents the rates in year y, and R_y is the revenue in year y. Common to both adjustment equations:

- I_y represents the inflation factor or I-factor that is observed in each year (sometimes with a lag)
- X represents the productivity factor (or offset) or X-factor

18 "Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018-Decision," British Columbia Utilities Commission, In the Matter of FortisBC Energy Inc., September 15, 2014, p. 170.

19 See "Rate Regulation Initiative Distribution Performance-Based Regulation Decision 2012-237," Alberta Utilities Commission, September 12, 2012. The AUC also found that separate provisions for off-ramps and re-opening the case was not required. It concluded that "a specific facility for an off-ramp, as distinct from a re-opener, is not required in a PBR plan. All that is required, in the Commission's view, is an opportunity to re-open and review a PBR plan if a design or application flaw comes to light during the term of the PBR plan."

The inflation factor (I) in the price or revenue cap formula represents changes in the price of goods and services that the utility purchases in order to provide utility service, and means that rates or revenues increase with inflation (i.e., before subtracting the productivity factor (X), remain constant in real terms). The productivity factor determines the rate at which rates or revenues increase or decrease in real terms.

The I-factor may be specified differently in different jurisdictions. For instance, in Alberta, the I-factor is defined as a weighted average of changes in an index of wages and a general consumer price index (CPI), the latter being a proxy for non-labor utility inputs.[20]

The X-factor adjusts for *anticipated* changes in cost (in real terms) that are to be expected over the term of the plan. The X-factor is typically set at the outset of the plan in the rate case. It is usually fixed for the term of the plan but can sometimes be different in each year in order to provide a profile of real rates/revenues over time—such is the case for Ausgrid in Australia. The X-factor is sometimes set on the basis of a "productivity study" and sometimes on the basis of forecasting revenue requirements for each year of the plan term.[21]

Price cap and revenue cap plans also include other elements to reduce a utility's risk exposure in between rate cases, such as capital riders/trackers allowing to fund certain capital-related costs that may be required or mechanisms to account for the effect of exogenous and material events, which may occur. For example, the Alberta distribution utilities' current PBR plans include an extensive capital rider/tracker (K-factor) that provides additional funding for programs that grow faster than I-X, effectively on a flow-through basis.[22] In Australia, costs for capital projects that are well-defined but have uncertain need or timing are estimated at the start of the rate term, and a distributor may request additional revenue for those costs only when its "trigger" event occurs (e.g., when necessary approvals are finalized). We are not aware of any price or revenue cap plans that are currently applied to electric and gas distribution utilities in the U.S., although some were in place in the 1990s and 2000s. However, specifically defined price and revenue cap

20 See Alberta Utilities Commission, Decision 2012-237, § 5.2.

21 The X-factor is based on a productivity study in Alberta and Ontario. In Great Britain and Australia, it is based on forecasting revenue requirements (including an assumed rate of efficiency improvement).

22 In these utilities' most recent PBR rate case, the K-factor was significantly reduced in scope, basing its value on trending of historical average capex and netting off programs with headroom.

plans are more common abroad. In Alberta, Canada, price cap plans are currently in place for all of the electric distribution utilities and revenue (per customer) cap plans are in place for all natural gas distribution utilities.[23] Also, all electric distribution utilities in Ontario, Canada and New Zealand are regulated under price cap plans. Australian electric distribution utilities currently are regulated under revenue cap plans, having recently switched from price cap plans. Great Britain's RIIO plan can also be characterized as a revenue cap plan. (We discuss this plan in greater detail in section V.)

F. Summary Findings

Agreeing upon the duration between rate cases, as opposed to allowing rates to be fully reviewed whenever utilities (or other parties) request a rate case, has become a relatively widely applied regulatory approach. We, and other analysts, consider this moratorium on further rate cases and potential increase in regulatory lag to be the basis of broad-based incentive frameworks. While the term of a plan gives a good indication of the "strength" of cost control incentives a utility has, it is important to analyze a broad-based incentive framework in its entirety, taking into account its other key features, such as the ones discussed in the above section—i.e., scope of the plan, use of historical or forecast of costs to determine rates, and type of ARM. For instance, plans with a long term may have a narrower scope, which will mitigate the risk borne in between rate cases.

We, and others who have conducted similar "classification" studies,[24] have identified and included relatively short MRPs with no "I-X" indexing (as found typically in the U.S.—see Table 2 above) as an application of PBR because they were deliberately designed to motivate utilities (via the possibility of earnings enhancements) to improve operations and efficiencies beyond what would be realized under more traditional regulatory schemes. Some regulators recognize this point and refer to their relatively short MRP plans as PBR. However, other regulators are less concerned with the labeling and more focused on the overall effectiveness of their approach.

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23 A revenue per customer cap means that revenue per customer is adjusted annually instead of the overall revenue. This mechanism protects utilities for decrease in use per customer but it does not protect these for decrease in the number of customers.

24 For more examples see Dan Aas and Michael O'Boyle, "You Get What You Pay For: Moving Toward Value in Utility Compensation," Energy Innovation, June 2016; Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives," National Regulatory Research Institute (NRRI), April 2014.

(For example, MRPs with ARMs are applied to utilities in California, but regulators there do not refer to their three-year GRC model as a form of PBR.)

By operating within the overall existing regulatory approach, relatively short MRPs provide a practical approach to introducing additional incentives into more traditional utility regulation. They can be contrasted to more comprehensive overhauls of a regulatory scheme, as exemplified by the Great Britain's RIIO.

III. Targeted Performance Incentives

TPIs refer to the assignment of financial rewards and/or penalties to narrowly specified areas of utility performance or policy outcomes. We have reviewed and analyzed a wide range of TPIs in the U.S. and other parts of the world over the course of the last decade,[25] and have found them to be very widely applied. Regulators usually require utilities to report on a variety of performance measures, sometimes at a detailed level, but only a subset of these usually have the financial incentives attached that make them TPIs. The scope of most TPIs covers areas of utility operations, mainly reliability, customer service, and employee safety, which we collectively refer to as "traditional" TPI measures.

The TPI concept has also been expanded to include additional areas, notably those associated with regulatory policy goals such as Distributed Energy Resource (DER) integration and customer engagement. These TPIs are designed to motivate utilities to achieve outcomes that they might ordinarily be disinclined to pursue absent some additional incentive. We refer to these TPIs as "emerging" TPI measures. Finally, utilities and regulators have been engaged in a discussion concerning the importance of energy efficiency (EE) as well as the potentially detrimental effect that EE can have upon utility revenue recovery. Many jurisdictions have thus implemented incentive plans to motivate utilities to realize EE policy goals. We provide a more thorough review of these three forms of TPIs below.

A. Traditional TPIs

The TPIs that we have dubbed as "traditional" tend to address the foundational aspects of utility operations: providing reliable and safe electricity or gas services; being responsive to customer needs, inquiries and requests; and keeping employees safe. Utilities have a long history of

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25 For example, see "Approaches to Setting Electric Distribution Reliability Standards and Outcomes," Serena Hesmondhalgh, William P. Zarakas, and Toby Brown, prepared for the Australian Energy Markets Commission, January 2012. This report provided detailed reviews of TPIs (or their equivalents) in Australia, New Zealand, Great Britain, Italy, the Netherlands, and a range of jurisdictions in the U.S., with particular focus provided to New York and California. http://www.brattle.com/system/publications/pdfs/000/004/670/original/Approaches_to_Setting_Electric_Distribution_Reliability_Standards_and_Outcomes_Hesmondhalgh_Zarakas_Brown_Jan_2012.pdf?1378772119

tracking metrics in these areas as part of ongoing management and process improvement. In addition, regulators typically require that electric utilities report performance measures at defined intervals, usually on an annual basis. Such reporting may be strictly informational. In most cases, regulators expect utilities to achieve certain levels of performance and may begin a proceeding to investigate the causes for consistently poor performance; they may also develop recommendations for improving the situation. Many jurisdictions have taken this a step further, however, and developed performance incentives applicable to some or all of the reported measures. For these, the utility is expected to achieve a specifically defined level of performance and is penalized and/or rewarded when performance strays too far from the targeted levels. Recent surveys indicate that at least 17 states have formally adopted TPI plans, covering 72 electric and gas distribution utilities.[26] (See Appendix A-2, Survey of U.S. Traditional TPI Plans.)

TPIs for traditional utility operational areas usually have four elements: 1) definition of the measure itself; 2) a target or benchmark; 3) a range of acceptable performance, typically specified by a deadband or neutral zone; and, 4) provisions for penalties, as well as rewards in some cases, when performance falls outside of the deadband.

1. Performance Measures

The main measures included under traditional TPIs can be grouped into two primary categories: system reliability and customer service. Other areas, notably employee safety, are also sometimes included in this area. A survey of the measures of system reliability that are included in traditional TPI plans is provided in Appendix A-3, Summary of Traditional TPI Measures – System Reliability. The appendix indicates that reliability measures span outages (in terms of duration and frequency), individual circuit performance and problem areas of the distribution infrastructure (e.g., pole replacements). Most measures of system reliability are applicable to electric utilities but a few are gas specific, mainly odor detection.

The appendix also demonstrates that performance measures can also be specified in terms of the level of reported aggregation (i.e., system-wide versus geographical or sub-system disaggregation). TPI reliability measures range from the widely accepted and applied measures of

[26] Review and survey conducted by O'Neill Management Consulting LLC. "Recommendations for Strengthening the Massachusetts Department of Public Utilities' Service Quality Standards." December 13, 2012.

reliability such as the system average interruption duration index (SAIDI), to specific measures that address specific infrastructure concerns (e.g., replacement of damaged poles). The New York Public Service Commission (NYPSC) has adopted very detailed measures of system reliability, including measures such as repairs to damaged poles and removal of temporary shunts,[27] on a geographically disaggregate level for Con Edison (the state's largest utility) but comparatively less detailed sets of measures for the state's other utilities.

A review of the measures of customer service and employee safety that are typically included in traditional TPI plans is provided in Appendix A-4, Summary of Traditional TPI Measures – Customer Service and Employee Safety. Customer service measures tend to address utility responsiveness (e.g., service appointments kept and telephone answering speeds) and accuracy (e.g., billing accuracy and on-cycle meter reads) in dealing with customers, as well as with measures of customer satisfaction.

Each of the TPI measures addresses a specific area of potential concern. However, TPIs need to be considered in their totality in order to ensure that any overall TPI framework is not overly burdensome. At the same time, areas of concern should not be sacrificed in the name of simplicity. A good example of this balancing is found in the California Public Utilities Commission (CPUC) decision for San Diego Gas & Electric Company's (SDG&E's) 2008 GRC. During the rate case process, a proposal was made to expand the field service order appointment TPI into multiple separate TPIs, each reflecting a specific aspect of the broader field services.[28] However, in response, the CPUC found that the TPI did not need to be further segmented and concluded that using a single TPI served to "simplify the mechanism."[29]

Also, finding the right mix of TPIs is an ongoing exercise; the specific measures included in a performance incentive plan may change over time to reflect technological shifts, data availability and/or priorities. For example, in 2008, the CPUC deleted one reliability TPI and added two

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27 A shunt is an electrical cable or conduit that has been installed between two points to divert current from one path, which is no longer in use, to another path.

28 This proposal was made by the Division of Ratepayer Advocate (DRA).

29 CPUC Decision on the Test Year 2008 General Rate Cases for San Diego Gas & Electric Company and Southern California Gas Company (08-07-046), July 31, 2008, p. 54 (CPUC Decision 2008).

others to address more specific concerns[30], and the NYPSC recently dropped the meter reading performance incentive from the National Grid TPI plan.

In our view, it is sensible for regulators to adopt fewer, rather than many, TPIs when initiating a performance incentive plan. It may be tempting to adopt a large-scale system of TPIs in order to address the concerns of the many parties to a regulatory proceeding. However, it should be remembered that reporting as well as reviewing TPI results involves time and resources on the parts of utilities and regulators, respectively, and that TPIs can be refined and/or expanded in the future, as experience is gained.

2. Performance Targets

A performance target is the quantified level of service (for a particular performance measure) that the utility is expected to provide on an ongoing basis. As we discussed, ideally, this level should be set to balance relevant benefits and costs. Extremely high levels of service quality may be feasible for a utility to achieve, but it may represent a level that is far above recent performance and may come at a very high cost. Its cost may also exceed the value that customers place upon such a high level of service quality. In addition, as referenced in our discussion concerning the principles that guide the design of TPIs, the performance target should be set at a level which the utility can realistically achieve. Setting a performance target at a level that is unreasonably demanding (or, conversely, is too easily achieved) removes the motivation (or incentive) that is a key principle underlying TPI plans.

Historic utility performance data, either for an individual utility or for the industry overall, is frequently used as a proxy for the ideal levels of service quality are typically sought.[31] National benchmarking data (i.e., indicators of average or best-in-class performance) provides a large data set of utility performance, which can be used to infer the balance between marginal costs and marginal benefits on average. However, they may not be fully relevant in specifying a goal for an individual utility, as there are a wide range of differences in characteristics (e.g., size or density)

[30] Ibid., p. 66-71.

[31] This assumes that past interactions of utility management, customers, and regulators have managed to produce levels of service quality that reasonably approximate ideal levels.

across the utilities making up the benchmark panel.[32] In addition, some areas of utility operations (e.g., areas of customer service) are less amenable to quantification in benchmarking studies.

The historic performance of a single utility is more commonly employed to determine target levels in TPIs. This approach eliminates the need to control for relevant differences among utilities (in a benchmarking panel), but it also assumes that, over time, the utility appropriately estimated the service level that balances marginal benefits (to customers) and its own marginal costs. In practice, historical data for utilities are perhaps the only data set that regulatory commissions can reasonably expect to be available at a detailed and consistent level. Averaging historic performance (frequently over ten or so years) should provide a reasonable basis for establishing TPI performance targets. Less common is the use of a rolling average to set performance targets; that approach could distort incentives for improvement. Constantly raising the bar (assuming utility performance is improving over time) makes it increasingly more difficult to meet performance targets going forward.

In some cases, realized levels of service quality may have increased due to advances in technologies, enhanced investments and/or specific improvements in business processes. In these cases, regulators might consider using more recent performance data in setting a benchmark, provided the evidence is clear and the causes of the observed trend in realized service quality are well understood.

Finally, we are aware of one instance in which performance targets are set through a comprehensive review process, through which historic performance, input and comments from the utilities and other parties, and other considerations are taken into account in setting perform targets for TPIs. This is the case for Con Edison in New York and appears to involve considerable effort in compiling and analyzing all of the input to arrive at an acceptable target level.

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32 Electric utilities frequently undertake benchmarking studies, which compare company performance over a range of metrics with the corresponding performance of a “peer panel” of utilities. These studies are typically based on publicly available data (notably Federal Energy Regulatory Commission (FERC) Form 1 data and reports filed by utilities with state regulatory commissions) and on proprietary data sources.

3. Deadbands or Neutral Zones

In practice, it is difficult to estimate precisely the ideal level of service quality because there is considerable uncertainty about the relevant benefits and costs of service quality. Furthermore, the relationship between utility actions to enhance service quality and realized service quality typically cannot be described with perfect accuracy because of the influence of variety of uncontrollable and unpredictable factors. Consequently, TPI plans typically include a deadband, or a neutral zone; i.e., a range around the target level of performance in which the utility's financial position does not vary with the realized level of service quality. The extent of this range should reflect the variability of factors associated with achieving target levels of service quality. An overly restrictive (i.e., tight) deadband can mean that a utility may be penalized (or rewarded) for slight variations in factors that are beyond its control or capability to foresee.

Deadbands can be set based on percentages, e.g., the deadband surrounding SDG&E's customer service targets is +/-1%. However, they are more frequently set on a statistical basis involving standard deviations, a widely used and well-accepted statistical measure which indicates the range and variability of a series of observations. A deadband equal to +/- one standard deviation should account for roughly 68% of random events that affect utility performance.[33] Performance that falls outside of +/- one standard deviation can then be attributed to non-random events; that is, actions that were under the utility's control.[34] Deadbands defined in terms of standard deviations are used in several TPI plans, e.g., by the Massachusetts Department of Public Utilities (DPU) in the performance incentive plan applied to National Grid.

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33 The use of the standard deviation as a deadband mechanism presumes a "normal" distribution of performance outcomes. Graphically, normal distributions resemble a bell curve. Under a normal distribution, observed performance will ultimately fall within one standard deviation of the average about two-thirds of the time. Furthermore, the service quality metric averages will converge to the normal distribution in the long run, even if they exhibit a non-normal distribution in the shorter term.

34 Plus or minus (+/-) one standard deviation is commonly used as zone to capture random events in TPI plans and in other statistical analyses because it is a reasonable indicator of randomness. It is also used because it is a round number, as opposed to, say, 0.80 standard deviations or 1.1 standard deviations.

4. Incentive Structure

The incentive provision of a TPI refers to the structure through which the utility is penalized (or rewarded) for performing at service levels outside of the deadband. The components of a TPI incentive structure include:

- Symmetry, or the degree to which incentives allow for both penalties and rewards.
- Incentive Cap and Allocation, refers to 1) the maximum dollar amount of penalties and/or rewards (also referred to as the TPI's maximum "revenue exposure"); and 2) the levels of penalties (or rewards) assigned to individual TPIs.
- Shape and Slope of the incentive formula, which reflects how quickly penalties are assessed and/or rewards are earned. For example, a steep incentive curve means that the maximum penalty may be incurred faster (i.e., with less leeway after utility performance falls out of the deadband) than would be the case under a flatter incentive curve.

a. Symmetry

Most traditional TPIs are asymmetrical downward; that is, they apply a penalty only when performance is not met, and do not apply any reward when target performance is exceeded. For example, the TPIs applied by the NYPSC to Con Edison and National Grid include incentive provisions for penalties alone.[35] In contrast, the design for the few examples of emerging TPIs has been designed to be asymmetrical upward.

We have not found a formal explanation for these different approaches, but believe that it can be explained by assumptions concerning marginal costs and marginal benefits. The asymmetrical downward design applied to traditional TPIs is likely based on the understanding that the targeted performance level is the point at which marginal cost roughly equals marginal benefits. This means that utilities should make expenditures to meet this level in order to satisfy

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35 One exception may be associated with Con Edison's Company's program to replace leak prone pipe (LPP) under which the utility would receive an incentive payment (i.e., reward) if it reduces its backlog of gas leaks below specified targeted levels. However, the LPP is associated with a major capex project and may be regarded as an associate incentive for performance rather than a TPI. Another exception may be in Massachusetts where National Grid previously could use superior performance to offset TPI penalties, though did not receive any specific reward payment for superior performance. This offset provision was dropped from the TPI plan in 2015 after a DPU review of their TPI mechanism. See Order D.P.U. 12-120-D.

customers. However, it also suggests that customers do not value higher levels of performance, and spending more in order to improve performance beyond this level would create a situation in which marginal costs exceed marginal benefits.

The case is quite different with respect to the emerging TPIs. Regulators likely have concluded that customers (and society) benefit from the achievement of certain policy goals, such as the integration of DERs into utility distribution systems. However, utilities see little reason to incur costs to realize these goals, as it adds little to maintaining or improving their performance in core service areas and, in addition, may arguably detract from some elements of system efficiency. Designing an asymmetrical upward incentive structure therefore assumes that marginal benefits exceed marginal costs.

It is worth noting that the issue of symmetrical incentive design continues to be debated, even though asymmetrical downward incentives are the de facto norm for traditional TPIs. Guidelines for incentive regulation typically stress the importance of designing incentives such that financially favorable outcomes are as likely to be realized as unfavorable outcomes. In other words, TPI plan design should make it equally possible for a utility to earn its authorized rate of return, from a statistical perspective, than to under-earn. It has been argued that, with asymmetrical downward incentives, there is a higher probability that a utility will earn a rate of return that is lower than its authorized rate of return, thereby conflicting with the fair return standard. A case for symmetrical TPI incentives has also been made in California (which no longer applies a TPI framework to the State's utilities). There, the Commission stated that they reject "unbalanced incentives or limiting the mechanisms only to penalties: without rewards for marked improvement there is a lesser likelihood that the company will strive to exceed the target and only minimize the risk of penalty."[36]

b. Incentive Cap and Allocation

To our knowledge, all TPI plans include a maximum revenue exposure in order to provide a bound on the financial impacts associated with its performance in reliability and/or customer service. Maximum levels of exposure have been set in terms of annual revenues or in terms of basis points of authorized rates of return (subtracted from or added to the authorized rate of

[36] CPUC Decision 2008, p. 56.

return)[37] or as a percentage of revenue requirements. These incentives can be compared across plans because the measure for penalties and rewards under one method (e.g., basis points) can usually be converted into other terms (e.g., percentage of revenue requirements). These levels tend to be material but not overly high. For example, the maximum penalty for Massachusetts Electric was initially set by the DPU at 2.0% of the company's annual transmission and distribution (T&D) revenue requirements and subsequently raised to 2.5% of annual T&D revenues, while levels were slightly lower when the California utilities were regulated under a TPI framework (ranging from less than 1.0% to about 2.0%).

The incentive amounts for traditional TPIs were then allocated among the individual categories. The weighting of incentives for reliability TPIs tend to quite a bit higher than the incentive level assigned to customer service TPIs. For example, the maximum revenue exposure for reliability TPIs was 74% for Con Edison and 57% for National Grid in New York.[38]

c. Shape and Slope

A final element of specification for a TPI incentive structure involves how rapidly (or gradually) incentives are realized when performance is outside of the deadband. The shape and slopes of the functions that govern imposition of penalties (or rewards) varies across the jurisdictions that we reviewed, and appear to reflect specific views and issues. For example, the shape and slope of the incentive function that was applied in California, when TPIs were in place, is linear, is a step function in New York, and follows a combination step and quadratic function in Massachusetts. The difference in incentive structure is illustrated in Figure 2 below. (Although New York is not featured.)

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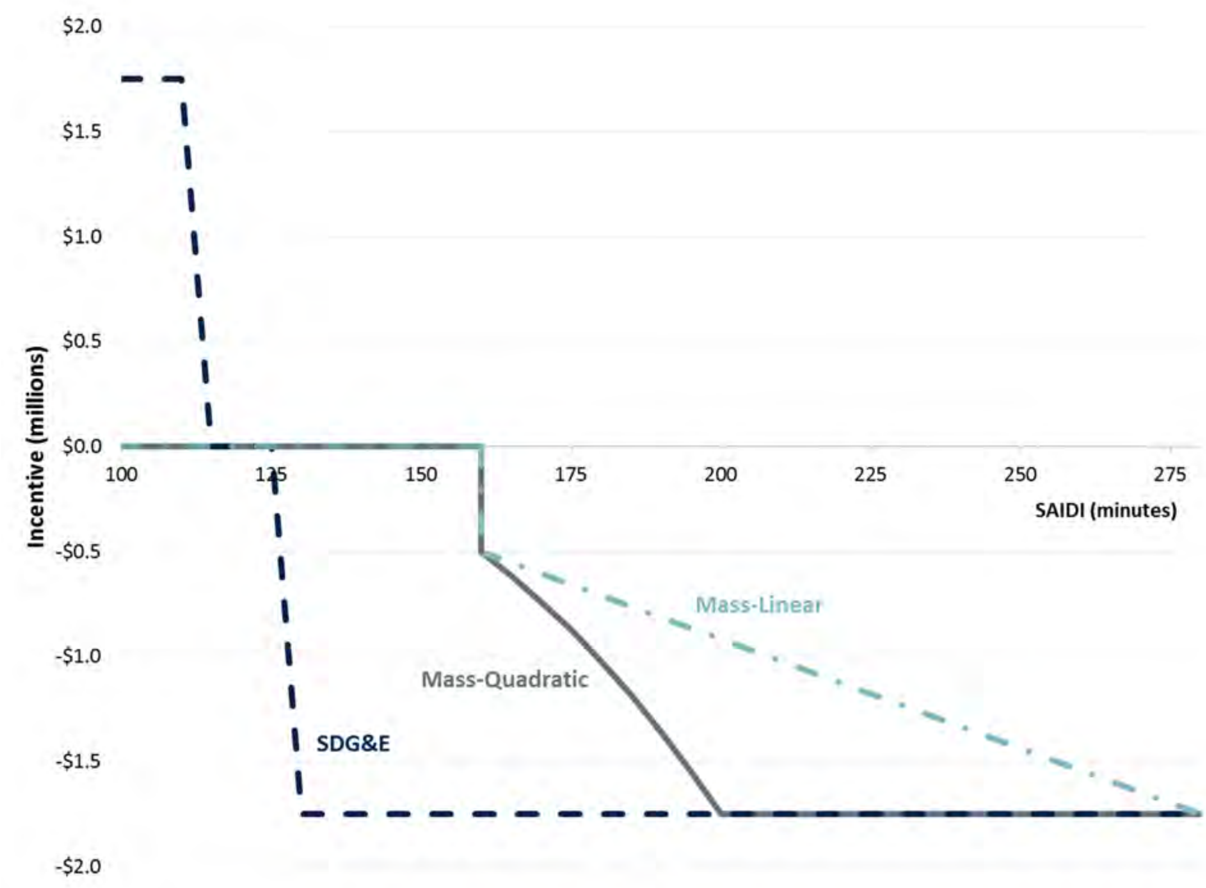
37 As part of the rate making process, regulators authorize utilities to earn a specified return on rate base. The rate of return is defined in percentage terms, which can be translated into dollars. A basis point is a financial convention equal to 1/100th of one percent. Specifying a TPI incentive in terms of basis points can thus be translated into dollars.

38 See William P. Zarakas and Philip Q Hanser, "Targeted Performance Incentives: Recommendations to the Hawaiian Electric Companies," Prepared by The Brattle Group for the Hawaiian Electric Companies, September 15, 2014.

Figure 2: Comparison of Incentive Structures



Source: See William P. Zarakas and Philip Q Hanser, "Targeted Performance Incentives: Recommendations to the Hawaiian Electric Companies," Prepared by The Brattle Group for the Hawaiian Electric Companies, September 15, 2014.

Figure 2 depicts three incentive structures applied to system reliability (SAIDI):

- SAIDI TPI applied by the CPUC for SDG&E, labeled "SDG&E" in the figure;
- SAIDI TPI used in Massachusetts at National Grid, labeled "Mass-Quadratic" in the figure; and
- A modified (non-quadratic) version of the SAIDI TPI used in Massachusetts, labeled "Mass.-Linear" in the figure.

As can be seen, the incentive structure for SAIDI at SDG&E is quite steep and has a very narrow deadband. This may be because the CPUC did not expect that SDG&E's SAIDI performance will vary significantly from targeted levels. However, if performance fell outside of the deadband, the utility would be penalized, or rewarded, $250,000 for each one minute up to the maximum revenue exposure for that TPI. The incentive function for the SAIDI TPI in California was, thus, steep but fully symmetrical.

The incentive function that the DPU applies to National Grid (labeled Mass-Quadratic) imposes an immediate step function penalty when performance falls out of the deadband (on the penalty side), followed by a slope function that, for the most part, is more gradual than the slope applied to SDG&E in California. We also included an additional curve (labeled Mass-Linear) to illustrate an incentive curve with a flatter slope.

A key point to note concerning the slope and shape of incentive curves concerns how quickly the incentive curves reach the point of maximum penalty or reward. The steepness of the curve labeled SDG&E indicates that it reaches the maximum penalty/reward for the TPI after it falls only modestly out of the deadband. In contrast, the flatter slope for Mass-Linear provides the utility considerably more "leeway" before it reaches the maximum penalty (or reward) level. The Mass-Quadratic curve intercepts with the maximum penalty level somewhere in between, at two standard deviations from the target performance level (or one standard deviation from the end of the deadband).

B. EMERGING TPIS

The performance incentives discussed above are aligned with core utility functions, and related performance incentives are designed to motivate utilities to maintain quality and perhaps even do their jobs better. However, many of the goals associated with transforming the traditional utility into a utility of the future run counter to what utilities have traditionally wanted to do from a financial or business culture perspective, and may involve activities that penalize utility financial performance.[39] Thus, regulators are considering new sets of TPIs, addressing outputs that fall outside of traditional performance measures.

The NYPSC has initiated a proceeding to develop a new set of incentives, referred to as Earnings Adjustment Mechanisms (EAMs), which are "directed not to traditional basic service but to new types of performance expectations. Some of these new expectations run counter to conventional

39 The utility of the future ("UoF") is a widely applied term referring to the evolving roles and business models for the next generation of electric distribution utilities. Other names include Utilities 2020 or Utility 2.0.

methods of operation and, importantly, also run counter to the implicit financial incentives that are embedded in the cost of service ratemaking model."[40]

Staff identified five near term outcome-based EAMs: peak reduction, EE, customer engagement, affordability, and DER interconnection.[41] Each is supposed to address a specific policy goal. For example, peak reduction, one of the immediate priorities for New York's *Reforming the Energy Vision* (REV) implementation, is an attempt to improve the efficiency of capital investment (referencing the low asset utilization of generating facilities in New York).

New York's six investor-owned utilities are responsible for proposing EAMs and are currently in the process of doing so. Several EAM specifications are worth noting. First, the EAMs are supposed to be outcome based, and need not be confined to activities over which the utility has direct control. Second, ideally EAMs should be set on a multi-year basis in order to allow sufficient time to develop sought after outcomes. Third, the maximum amount of earnings associated with all EAMs is set at 100 basis points (at least for the first round) and are non-symmetrical and positive only, which departs from the NYPSC's approach to several of its traditional targeted performance plans. Financial incentives embedded in EAMs are in addition to utility returns included in: 1) general rate cases and 2) other TPIs concerning measures, such as SAIDI and customer service. Thus, the potential 100 basis point adder to their overall profits represents a material amount (since the cost of equity is roughly 10%, 100 basis points represents a 10% return on a tenth of the equity base).

New York's EAMs are also of interest because the New York Commission believes that utilities will find themselves operating under fundamentally different business models in the future. Per the Commission: "EAMs are best thought of as a bridge….our expectations that through the opportunity to earn from platform revenues that produce sustained value to end-use customers

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40 "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," NYPSC, Case 14-M-0101, May 19, 2016 (NYSPSC Ratemaking Order, 2016).

41 Interconnecting DERs, such as rooftop PVs, provides a particularly pointed example of how a policy goal may run counter to a utility's financial interests. It is well known that such interconnection will reduce utility volumetric kWh sales. In addition, some analysis indicates that payments to rooftop PV customers net metering arrangements exceed the utility's avoided costs. Thus, the utility is presented with contradictory goals: interconnecting DERs on the one hand and optimizing its financial performance on the other.

and utility shareholders, the need to establish specific EAMs to accompany the same consumer benefit will diminish."[42]

C. ENERGY EFFICIENCY TPIS

The importance of EE as a demand side resource has continued to grow as utilities and policymakers address emissions reduction goals and seek to find non-wires alternatives (NWA) to spending in electric distribution systems. Utility spending on EE has been estimated to have grown from less than $1.5 billion in 2004 to about $7.7 billion in 2016.[43] However, utilities may still view EE, even when efficient from a benefit-cost analysis perspective,[44] as leading to lost sales and accompanied by a negative financial impact. Regulators have responded by developing incentive mechanisms to motivate utilities to proactively pursue EE goals.

A summary of the TPIs for EE by state is provided in Appendix A-5, Survey of Energy Efficiency TPIs. As included in the appendix, a recent survey indicates that 24 states and the District of Columbia (D.C.) have specific EE TPIs in place, which fall into four basic incentive approaches:[45]

- **Shared Net Benefits Incentives**: In this model, the benefits from EE programs, measured as the difference between program costs and estimated dollar value of saved kWhs, is shared between the customers (ratepayers) and the utility.
- **Energy Savings-Based Incentives:** In this model, the utilities are eligible to receive an incentive (frequently measured in terms of a percentage of total program costs) if they achieve a pre-determined energy savings target (measured in kWhs).
- **Multifactor Incentives** are more complex in nature than the shared net benefit and energy savings based incentive models. Under this model, incentives are usually tied to a range of measures, including energy savings as well as other factors, such as job creation and/or customer service quality.

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42 *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* (NYPSC May 19, 2016), p. 60.

43 "Executive Summary: The 2016 State Energy Efficiency Scorecard," The American Council for an Energy Efficient Economy, 2016.

44 There are five primary benefit-cost tests that have been applied to EE programs in the U.S.: the participant test (PCT); the program administrator cost test (PACT); the rate impact measure (RIM); the (TRC) test; and the societal cost test (SCT).

45 Seth Nowak et al., "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," American Council for an Energy Efficient Economy, May 2015.

- **Rate of Return Incentives** are an infrequently used mechanism that equates EE spending with rate based supply side expenditures, thereby allowing utilities to earn a rate of return on EE spending.

All of the EE TPIs are asymmetrical upward (i.e., reward only). The shared net benefit incentive approach is the most widely used (11 states and D.C.). Five states apply EE incentives following the energy savings model. An additional five states, as well as the D.C., currently apply a multifactor incentive model; e.g., Efficiency Vermont (EVT) has a number of quantifiable performance indicators (QPIs) including total resource benefits and both summer and winter peak demand reduction.[46] Finally, New Mexico is the only state that uses a rate of return mechanism, meaning that it provides an incentive for EE spending that is not tied directly to energy savings, although EE spending is still budgeted and trued up annually and most pass the total resource cost (TRC) test.

D. Summary Findings

TPIs are widely applied incentive mechanisms, mainly because they can be directed to specific areas of utility performance and are easy to understand. However, the details of TPI plans typically involve considerable specification and financial and/or statistical analysis. Traditional utility performance measures (e.g., outages and areas of customer service) are quite amenable to such detailed examination because utilities typically track these measures at a detailed level and maintain time series data sufficient to enable meaningful analysis. These TPIs are frequently included as an important element of overall PBR frameworks, together with, for example, MRPs.

Strong performance in traditional measures does not necessarily advance regulatory and policy initiatives, such as the integration of distributed energy resources into a utility's power portfolio (when vertically integrated) or into its distribution system planning. The "newer" emerging TPIs tend to address these issues; i.e., providing incentives for utilities to proactively take steps to realize policy goals and/or make the utility more amenable to a UoF environment. These TPIs may also be incorporated into a PBR framework.

The evolution of the portfolio of TPIs has also had an impact on the associated incentive mechanisms. Regulators have largely viewed the targets set for traditional TPIs as being placed at

46 "2015 Annual Report," Efficiency Vermont, October 24, 2016.

the point at which marginal costs are roughly equal to marginal benefits. Thus, they were hesitant to reward the utility for performing at levels that exceeded targets and instead emphasized penalties when utilities failed to meet targets. The situation is reversed somewhat with respect to the emerging TPIs. In this case, utilities do not see sufficiently marginal benefit to advance policy goals. Regulators, in New York with respect to EAMs and in other states with respect to EE, have thus added incentives asymmetrically upward (i.e., rewards only).

IV. Supplemental Incentives

Regulators have implemented a wide variety of adjustment mechanisms that are applied outside of rate cases, ranging from fuel adjustment and purchased power adjustment mechanisms to special riders/trackers and formula rate adjustments. Basically, these mechanisms adjust rates, either overall or as a separate line item, to cover the actual costs of agreed upon areas of cost or investment, such as targeted investment in grid modernization, reliability and/or resilience. The end result is that utilities realize revenues sufficient to recover the costs for the agreed upon mix of capital and operating expenditures.

We include these adjustment mechanisms in our compilation of PBR plans and elements to provide a complete overview, more so than suggesting that they are foundationally PBR. There is an incentive dimension to specialized riders/trackers and formula rate plans; that is, they were designed to induce utilities to invest in areas that they considered risky (in terms of possible disallowances or delays in cost recovery). However, on the other hand, an equally strong argument can be made that C-o-S regulation plus revenue adjustment mechanisms, such as formula rates, may come close to being the opposite of PBR, because the true-up nature of the mechanisms provides a substantial safeguard to utilities, more so than a balance between risk and reward. Overall, we regard these more as supplements or adjuncts to an overall incentive scheme rather than an essential part of all PBR frameworks. If appropriately and proactively applied, riders/trackers or formula rates may serve to balance some of the risk that is included in other areas of a PBR framework, and may thus permit stronger incentives to be applied in the balance of the framework (e.g., by lengthening the period between rate cases).

A. Formula Rates

Generally, in the U.S., formula rates refer to an adjustment mechanism through which a utility's rates are adjusted, either overall or via separate line items on customer bills, to ensure that the utility earns its authorized return on equity overall or with respect to a targeted area of investment. Formula rates thus adjust revenues according to costs, usually reflecting recent actually incurred costs but adjustments may also be based on projected costs. As a result, changes in recorded costs are quickly reflected in revenues, thereby dampening variation in achieved returns and weakening incentives to control costs. Recent surveys of regulatory frameworks indicate that nine states have specifically defined formula rate plans covering 17 utilities.[47] (See Appendix A-6, Survey of U.S. Formula Rate Plans.)

Two applications of formula rates are particularly relevant to this review of PBR frameworks.

- Formula rates as applied to utilities in Illinois, notably Commonwealth Edison (ComEd), and designed to motivate utilities to invest in grid modernization.
- A true-up and earnings sharing mechanism that has been applied to several utilities in the southeastern U.S. (e.g., Alabama Power)

1. Illinois Formula Rates

The formula ratemaking approach in Illinois involves resetting the affected utility's revenue on an annual basis through a streamlined regulatory process (i.e., one that does not involve a formal rate case). The formula rates model was established by legislation in Illinois in 2011 (i.e., the Energy Infrastructure Modernization Act, or EIMA). The primary purpose of the legislation (and, thus, formula rates) is to provide an incentive for utilities, notably ComEd, to invest in distribution system assets, especially concerning investments that smarten the grid assets, which might have been viewed by the company as too risky to make in the current environment.

ComEd represents that its formula rates are designed to: 1) reduce the complexity of regulatory filings; 2) reduce risk concerning utility earning a return on prudent investments in distribution operations; 3) assure that investments are paying off by requiring compliance with performance measures; and 4) protect consumers from the impacts of very large levels of investment by capping increases in customer bills (in the initial years).

Specifically, in return for being granted a pre-determined rate of return on their investments, the utilities were obligated to make certain types of investments in the distribution grid. They also entered into a concomitant obligation to meet certain performance metrics. It was expected that such investments would improve system reliability (i.e., reduce outages) and raise customer satisfaction levels—a direct response to the anticipated heightened demands for high quality / low outage power from its customers and overall preparation for ComEd to continue to transform itself into a UoF. The formula rates also allowed for the rapid provision of cost-effective demand-side programs such as EE and demand response.

47 EEI, "2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry."

ComEd's formula rates apply to all investments that the company makes in its distribution utility operations. This includes all distribution system infrastructure assets (such as poles, transformers and substations, to name a few) as well as the information systems, covering hardware and software, which enable billing and other customer interactions. Specifically, the formula allows for ComEd to recover revenues equal to the sum of (a) a preset rate of return on its rate base,[48] and (b) its operation and maintenance (O&M) expenditures provided certain metrics were met. However, ComEd's earnings under formula rates is subject to the utility meeting a set of metrics concerning reliability, outage duration and frequency, safety, customer service, efficiency and productivity, and budget control. If the preset performance metric goals—established as incremental annual goals to meet the overall ten-year goals—are not satisfied, there is an associated penalty, which decreases the allowed ROE.

The formula rates also established a maximum and minimum achieved ROE, a range that is often referred to as a "collar." This ROE collar was set to be 50 basis points above and below the allowed ROE, after adjusting for penalties. This ROE collar adjustment provided a true-up mechanism for the utility to recover lost revenues. Should the utility find that it earned an ROE over the past year more than 50 basis points below its allowed ROE (i.e., the utility under-earned), then the company would increase its revenue requirement to adjust for the historical under-earning. Alternatively, if the utility found that it earned an ROE more than 50 basis points above its allowed ROE, then the company would reduce its revenue requirement to account for the historical over-earning.

The company files a report each year along with its rate case filing to track its improvements and ability to achieve these metrics. The performance metrics can be described in three groups: reliability-related metrics, advanced metering infrastructure (AMI) related metrics, and opportunities for minority-owned and women-owned business enterprises (MWBE). The five reliability-related metrics measure how well the utility maintains electricity service or how quickly the utility re-establishes service after an interruption. The four AMI-related metrics measure how well the company is using the technology and functionality of its smart meters in reducing inefficiencies on the system. Finally, the MWBE metric measures the utility's annual funding of these MWBEs.

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48 For the formula rate plan, the authorized ROE is equal to the sum of the rate on 30-year Treasury bonds and 580 basis points.

2. Rate Stabilization and Equalization

Rate Stabilization and Equalization (RSE, or Rate RSE) is a formula ratemaking mechanism currently in place in several states in the southeastern U.S., notably in Alabama where RSE originated. Rate RSE is applied to most, if not all, utilities in Alabama including Alabama Power Company (APCo), a vertically integrated electric utility, and Alabama Gas Company (Alagasco). In addition, similar rate mechanisms have been applied elsewhere, primarily to gas and water utilities.

Rate RSE began in Alabama in 1982, in response to a nearly continuous stream of rate cases initiated by APCo to address rising costs,[49] and has been used since then, with only minor adjustment to the original specification. Under the RSE plan, Commission Staff annually (in January) reviews APCo's projected return on equity (ROE), compares it to the authorized range, and adjusts base revenues and rates, if needed, to keep the ROE within that range or deadband. The RSE limits the amount of upward adjustment in any given year to not more than five percent, and the average of two consecutive annual increases to not more than four percent. Staff also compares projected ROE with year-to-date actual ROE (in March) and adjusts rates accordingly if needed.

Rate RSE has been advanced by its architects and various industry analysts as an innovative ratemaking mechanism because it has fulfilled three key regulatory objectives in Alabama and the southeast:[50]

- It provides greater opportunity for detailed cost reviews by Staff outside of litigious rate case environments;
- It smooths out rate adjustments, rather than the frequent and large rate increases experienced between 1968 and 1982; hence, the title Rate Stabilization and Equalization; and
- It reduces regulatory lag, which may reduce incentives to control costs, but also provides greater financial stability to utilities. Financial instability and poor credit ratings

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49 APCo filed 10 separate rate cases between 1968 and 1982, brought about by increasing costs stemming from large-scale construction projects required to meet increasing customer demand. These included construction of hydroelectric and large coal-fired generation facilities, high voltage transmission lines, and two nuclear units.

50 EEI, "Case Study of Alabama Rate Stabilization and Equalization Mechanism," June 2011.

(reducing access to capital markets) were a problem for APCo prior to implementation of Rate RSE.

B. Riders and Trackers

Riders/trackers are rate mechanisms used for recovering certain operating expenses (opex) and capital investments.[51] Riders/trackers typically are designed to address specific and predetermined areas of expenditure , and are usually recovered either through adjustments to revenue requirements and rates (outside of a rate case) or through a separate line item on customer bills.[52] Because the rider/tracker process is typically independent of the rate case process, they are useful tools in overcoming regulatory lag and in generally reducing the risk for the utility by guaranteeing a return on the subject investment.[53] Riders/trackers can cover a wide range of cost areas (briefly summarized in subsection 1 below), ranging from the costs of purchased power and fuel to recovery of unplanned expenditures associated with storm response. We include so-called "capex riders/trackers" (summarized in subsection 2 below) within the scope of PBR because they proactively provide an incentive for utilities to invest in infrastructure.

1. Scope of Rider/Trackers

Recent surveys of riders/trackers indicate that every state and the D.C. have various riders/trackers in place covering 257 utilities.[54] (A summary of the riders/trackers in place by state are included in Appendix A-7, Survey of Utility Riders/Trackers). The appendix indicates that a wide range of riders/trackers are currently applied. Purchased power and/or FACs (in conjunction with balancing accounts) are perhaps the most widely used rider/tracker observed; they allow utilities to directly pass-through changing and generally uncontrollable fuel costs, albeit with a modest lag and sometimes with ex post prudence reviews.

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51 Most surveys use the terms riders/trackers and riders/trackers synonymously.

52 Specifically, the rider/tracker process involves setting up a non-fungible account of funds that can only be used for the stated purposes. The accounts are typically trued up periodically.

53 There are exceptions where riders/trackers can be combined with performance incentives such as Oklahoma Gas and Electric Company's (OGE's) Smart Grid Rider/Tracker Factor (SGRF).

54 "Adjustment Clauses, A State-by-State Overview," Regulatory Research Associates, August 2016. The count of riders/trackers included in this report may be understated; as it does not include the full scope of EE related riders/trackers.

EE or energy conservation riders/trackers are also widely applied.[55] These riders/trackers are mechanisms through which utilities recover the costs incurred in EE outside of a rate case. In addition, as discussed earlier, 25 states also currently have EE TPIs in place, which are incentives (i.e., payments to utilities for achieving goals) and are in addition to the cost recoveries enabled through the rider/tracker mechanism. Many states apply both EE riders/trackers as well as EE TPIs to the utilities that they regulate.[56]

There is also a broad "other" rider/tracker category included in the appendix. This covers a wide range of areas, typically including the unanticipated costs associated with storm recovery, higher than expected costs of uncollectible bills, and costs associated with pension obligations.

2. Capex-Related Rider/Trackers and Adjustment Mechanisms

Appendix B also provides details concerning riders/trackers that cover major capital investment programs. Under these mechanisms, the annual revenue requirements associated with program costs are recovered through an explicit rider/tracker or incorporated in utility rates in a predetermined fashion (i.e., outside of a rate case venue).

The Energy Strong Adjustment Mechanism (ESAM) applied to Public Service Electric & Gas (PSE&G) provides a good example of an investment program adjustment mechanism. The ESAM was designed to recover a major capital program with respect to asset hardening and system resilience, specifically requested by the New Jersey Board of Public Utilities (NJ BPU) and the State's Governor's office following the wide spread outages stemming from Superstorm Sandy. The $1 billion expenditure ($0.6 billion for electric and $0.4 for gas) is being made between 2017 and 2019.[57] As shown in the case study concerning presented in Appendix B-5, PSE&G's revenue requirement is updated and rates adjusted at predetermined intervals to reflect expenditures incurred on the Energy Strong program.

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55 At least 37 energy conservation riders/trackers are reported in the Regulatory Research Associates' report (2016). In addition, a 2015 EEI report noted that "Riders/Trackers for [Demand Side Management] expenses are ubiquitous so that there is less need for documentation." EEI Alternative Regulation, 2015, p.6.

56 We count at least 16 states where this is the case, however the actual number of states that apply both EE riders/trackers and EE TPIs may be greater.

57 NJ BPU, "Order Approving Stipulation of Settlement," Docket No. EO13020155 and GO13020156, (May 2014).

The Michigan PSC has applied a capex rider/tracker to DTE Gas in the form of an Infrastructure Recovery Mechanism (IRM). Specifically, the cost of service (i.e., annual revenue requirements) associated with defined programs (concerning meter move-outs, main renewals and pipeline integrity) is recovered through the IRM. Under this mechanism, program scope and costs are specified for a five year period (2017 through 2021). The IRM is adjusted annually to reflect the incremental investments made during the year, provided that planned investments were actually made. Program capex are rolled into (and recovered by means of) base rates, in the event that DTE files a rate case.

Riders/trackers have also been used to recover utility investments in smart grid and AMI, and the costs associated with utility promotion of distributed energy resources, notable residential and commercial rooftop photovoltaics (PV). For example, Southern California Edison (SCE) was granted a rider/tracker to cover the costs associated with its Solar PV Program (SPVP); that rider/tracker collects the difference between the actual incremental O&M and capital-related revenue requirement (i.e., depreciation, return on rate base, and applicable taxes) associated with the SPVP and the authorized SPVP revenue requirement forecast.[58]

C. Summary Findings

Formula rates and riders/trackers primarily provide utilities with cost recovery assurances (e.g., in the case of capex riders/trackers or formula rates in Illinois) and/or smooth out rate adjustments (e.g., in the case of Alabama's RSE). Some utilities as well as regulators consider these mechanisms to be incentive in nature because they motivate utilities to engage in large-scale projects, which they might otherwise shy away from due to the risk of not realizing sufficient returns. More accurately, formula rates and riders/trackers are more risk mitigation mechanisms than incentive mechanisms. Comprehensive formula rates, such as those applied to ComEd in Illinois, are largely incompatible with the incentive structure included in MRPs because they regularly true-up rates. Less comprehensive formula rates as well as targeted riders/trackers are candidates to be included as elements of an overall PBR plan, for example in conjunction with an MRP. However, the scope of the costs covered under formula rate and/or riders/trackers have a significant effect on the incentives embedded in the MRP. Specifically,

58 "Preliminary Statement: Solar PV Program Balancing Account (SPVPBA)," Southern California Edison, Cal. PUC Sheet No. 51428-E.

including a large amount of cost under formula rates and/or in riders/trackers reduces the amount of cost that is covered under the incentive structure included in an MRP. That is, rates are more connected to actually incurred costs and the utility has less opportunity for reward (or risk), thereby weakening incentives to control costs.

V. Integrated PBR Frameworks

We previously introduced and discussed the various elements of broad-based incentive frameworks (or MRPs), other incentive structures (such as TPIs), and supplemental incentive and/or risk mitigation mechanisms (e.g., capex riders/trackers). We also noted at the outset of this report that, when thoroughly examined, PBR plans are the product of combining these various elements into a single integrated regulatory framework which provides a balance of incentives, risk and reward.

We begin by providing a summary of the RIIO framework that has been applied in Great Britain. RIIO provides a good starting point in this discussion because it is widely cited as a leading and cutting edge example of PBR, is very comprehensive and integrated in nature, and, also was highlighted in Michigan's PA 341. Following that, we turn to a range of regulatory frameworks in the U.S., Canada and Australia that represent a range of incentive-based options.

A. RIIO

RIIO stands for Revenue = Incentives + Innovation + Outputs. The RIIO model used in the U.K. has received considerable attention among U.S. regulators when considering incentive structures and enhancements to C-o-S regulation. RIIO is an MRP that involves a high level of stakeholder involvement (i.e., a collaborative process between regulators and utilities) covering a relatively long period of time. Each utility must develop for approval an eight-year business plan, and RIIO sets the path of revenues for the whole of the eight-year period, with limited mid-period review.

RIIO was developed as an evolution from the "RPI-X" approach that the U.K. Office of Gas and Electricity Markets (Ofgem) had applied since privatization of the utility section in the 1990s. RPI is the Retail Price Index, a measure of inflation. Ofgem concluded by 2008 that RPI-X was effective in reducing costs but, in the process, had made utilities more risk-adverse.[59] It announced the RIIO framework in 2010 as a new model to incentivize innovation.

RIIO can be characterized by four main attributes. First, from a labeling perspective, RIIO uses a price control mechanism (RPI-X) with an eight year time period between rate cases, a relatively long horizon when compared to many other regulatory plans. This sets the regulatory framework up to provide incentives to utilities to control costs. (As we pointed out earlier, this is a foundational element of MRPs in general.)

Second, RIIO requires that utilities develop long-term business plans, and requires that stakeholders be included in the process. This results in RIIO being very process-oriented.

Third, RIIO is output-oriented. That is, the RPI-X framework also examines "outputs that network companies are expected to deliver to ensure safe and reliable services, non-discriminatory and timely connection and access terms, customer satisfaction, limited impact on the environment and delivery of social obligations."[60] Ofgem recognized that "an outputs-led approach would also enable us to hold the network companies accountable for delivery without bias towards particular delivery methods, providing strong incentives for innovation that drives efficient outcomes."[61]

This output-led approach involves TPIs that offer various types of penalties and rewards depending on utility performance against defined metrics. For example, Northern Powergrid (NPg) may receive a reward up to 0.4% of base revenue depending on its "time to connect" smaller customers. NPg also has a symmetrical incentive related to supply interruptions with a maximum reward or penalty of 250 basis points on return on regulatory equity per year. The RIIO model also includes incentives associated with utilities achieving special policy goals, such as the Distributed Generation Incentive and the Innovation Funding Incentive,[62] which are over and above the earnings coming through the RPI-X framework.

59 "Regulating Energy Networks for the Future: RPI -X@20 Recommendations," Ofgem, 2010.

60 RIIO: A New Way to Regulate Energy Networks, Ofgem Final Decision October 2010, Chapter 4.

61 *Ibid.*, at 4.7.

62 "Incentive on Connections Engagement (ICE) Guidance Document," Ofgem, April 2015.

Fourth, the RIIO framework attempts to remove utility incentives to build (that is, spend capex) versus other alternatives (such as outsourcing or leasing which is "expensed" rather than "capitalized"). Under a "totex" approach, utilities earn returns on the total expenditure (i.e., capex plus opex) over the whole life of utility assets, rather than on capital expenditures alone. In contrast, an initiative to reduce opex by one dollar has a different impact on achieved returns than does an initiative to reduce capex by one dollar under traditional regulatory accounting schemes, even though the overall benefit for society is the same (i.e., one dollar of savings). Under a totex approach, all expenditures are treated in the same way; i.e., opex and capex are not differentiated as is the case when applying traditional accounting rules. For example under the totex approach, a certain fraction of every dollar of expenditure is capitalized in rate base (say, 85%) while the balance is run through as a (non-capitalized) expense.

RIIO has attracted considerable attention in the U.S., as well as elsewhere in the world. Several regulators have or are considering RIIO as a potential regulatory model in their states. For example, Hawaii's recent docket to reexamine its decoupling included a proposal to implement a "Hawaii Clean Energy IBR" that specifically cited RIIO as a potential model.[63] Also, the various discussions, working groups and orders associated with New York's REV docket made numerous references to RIIO, either in its entirety or with respect to specific RIIO elements. To date, however, no states have implemented the RIIO framework.

Some analysts have concluded that, in practice, RIIO is not very different from other incentive approaches that are already in place in the U.S. For example, one industry research group concluded that, at its core, RIIO generally is simply a "performance-based revenue cap with decoupling," and, thus, not a major change.[64] And, ultimately, the NYPSC concluded that implementing RIIO would be time consuming and administratively burdensome, and opted not to pursue the RIIO framework at the current time. However, the Commission continues to be

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63 "Docket No. 2013-0141: In the Matter of Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited," Before the Public Utilities Commission of the State of Hawaii, September 15, 2014.

64 For example see: Joseph Kruger, "The Clean Power Plan and the 'Future-Ready' Utility," Resources for the Future, February 2016.

interested in the totex concept and decided that it should monitor Great Britain's experience with RIIO and explore similar alternatives in rate cases or other regulatory filings.[65]

RIIO represents a major commitment to a very comprehensive process, and has a comparatively long plan term of eight years. Implementing RIIO as it is being applied in Great Britain may be too much of a leap for utilities and regulators in the U.S.; however, elements of RIIO, notably totex, are more ripe for consideration in the near term.

B. Case Studies

We selected eleven utilities as case studies to demonstrate the range of options and applications when incorporating incentives into a regulatory framework. The scope of the utilities included is summarized in Table 3.

Table 3: Scope of Case Study Utilities

	Electric Distribution Utility	Gas Distribution Utility	Vertically-Integrated Utility	U.S.	International	RIIO
ATCO Electric	✓				✓	
ATCO Gas		✓			✓	
Ausgrid	✓				✓	
ComEd	✓			✓		
Con Edison	✓	✓		✓		
FPL			✓	✓		
Northern Gas Networks		✓			✓	✓
Northern Powergrid	✓				✓	✓
PG&E			✓	✓		
PSE&G	✓	✓		✓		
Xcel Energy, NSP			✓	✓		

As indicated in Table 3, the case studies include six U.S. utilities, two Canadian utilities, two utilities in Great Britain, and one Australian utility. They also span gas and electric utilities, as well as stand-alone distribution and vertically-integrated utilities. The eleven utilities are included in nine case studies in Appendix B. We combine the ATCO Electric and ATCO Gas utilities into a single case study, and also present NPg and Northern Gas Networks (NGN) in a single case study. In both cases, the gas and electric utilities are regulated under very similar frameworks.

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65 *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* (NYPSC May 19, 2016). The Commission also noted that "differences in accounting standards between the United Kingdom and the United States would complicate efforts to import the totex approach here."

A summary level comparison of the various regulatory plans is provided in Table 4.

Table 4: Characterization of Case Study Ratemaking Plans

				MRPs			TPIs		Investment Incentives	
	Utility	State	Traditional CoS	Stair-step Trajectory	"I – X" Revenue cap	"I – X" Price cap	Traditional	Emerging	Formula Rates	Broad Capex Mechanisms
[1]	ATCO Electric	Alberta, Canada				✓				✓
[2]	ATCO Gas	Alberta, Canada			✓					✓
[3]	Ausgrid	NSW, Australia			✓		✓	✓		✓
	ComEd	IL, US					✓◆		✓	
	Con Edison	NY, US		✓			✓	✓		
	FPL	FL, US		✓						
	NGN (RIIO)	England, UK			✓		✓	✓		✓
	NPg (RIIO)	England, UK			✓		✓	✓		✓
	PG&E	CA, US		✓						
	PSE&G	NJ, US	✓							✓
	Xcel Energy, NSP	MN, US		✓			✓			

Sources and Notes: See Case Studies in **Appendix B.**

The column "Broad Capex Mechanisms" has a checkmark for plans with relatively broad and substantive supplemental capex programs defined.

[1]-[2] The capex riders/trackers for ATCO Electric and ATCO Gas have become more limited in the next rate term (2018-2022) than they are under the current plan.

[2] ATCO Gas has a revenue per customer cap.

[3] The checkmark in the Emerging TPIs column refers to the new incentive program the Australian Energy Regulator is currently developing—the Demand Management Incentive Scheme—to motivate distribution businesses to invest in demand management.

A more thorough review of each of the regulatory frameworks applied to the utilities included in Table 3 and Table 4 is provided in Appendix B.

The English (NPg and NGN), Australian (Ausgrid) and Canadian (Alberta, ATCO Electric and Gas utilities) utilities have clearly defined PBR plans in place, based on MRPs structured with I-X based adjustment mechanisms and capex riders/trackers that place the recovery of costs for certain capital expenditures outside of the scope of PBR. In addition, Ausgrid, NPg, and NGN combine their "broad" framework allowing for incentives to control costs with targeted incentives to reach targets on specific outputs (TPIs). On the other hand, the framework under which the ATCO utilities (and all Alberta distribution utilities) are regulated solely communicates a broad incentive to control overall costs and does not have TPIs. Regulators as well as utilities in Great Britain, Australia and Alberta all regard their regulatory frameworks as PBR.

U.S. utilities with broad-based incentive frameworks tend to have a shorter term (typically three or four years), a broader scope, and a stair-step mechanism. As discussed previously, the characterization of such plans as "PBR" in not uniform. Many regulatory approaches include some level of incentive (beyond what is inherently included in traditional C-o-S regulation), however few if any would publicly characterize their plans as comprehensive PBR. The NYPSC is exploring new regulatory frameworks (e.g., including application of the totex concept) but has not formally adopted a regulatory framework that is specifically designated as PBR. However, in practice, it has placed Con Edison under an MRP with a stair-step ARM, implemented traditional TPIs (with provisions for penalties only), and is in the process of adding new TPIs that cover emerging issues concerning UoF implementation (with provisions for rewards only). Thus, for all intents and purposes, most analysts, including us, consider the regulatory framework applied to Con Edison may be PBR.

PG&E, FPL and NSP are also regulated under MRPs with stair-step ARMs. However, their plans are less "integrated" as they do not include TPIs. Similarly to Alberta, Canada, regulators will treat these dimensions in separate forums or as part of rate cases without defining any explicit targeted incentives. Indeed, these targeted supplements to traditional regulation sometimes require legislation (e.g., Florida's HB 7071, now indefinitely postponed and withdrawn for consideration, specified a TPI-type incentive mechanism).

PSE&G is regulated under a traditional rate case approach, with no explicit moratorium on rate cases during set periods, even though it has been eight years since its last rate case. Also, the New Jersey BPU does not apply any stand-alone TPI mechanisms to PSE&G, although performance criteria are attached to its ESAM capex rider/trackers – which is the primary reason that we include PSE&G in our case study panel. As we discussed earlier, we consider capex riders/trackers to be primarily risk mitigation mechanisms, more so than incentives (with their balanced share of reward and risk), and may provide an important component of an overall PBR framework. For instance, a noted in Table 4, some frameworks define relatively broad capex programs/riders/trackers in order to account for these separately from rate cases. That is the case for the "longer" broad-based incentive frameworks – i.e., the international examples of our sample.

ComEd is regulated under traditional ratemaking with the important formula rate supplement. ComEd represents what it and its regulators found traditional ratemaking ill-equipped to accommodate: the transition to a more modern and UoF shaped grid. They stated that "the changes to this industry require a new regulatory approach that results in manageable levels of risk by avoiding undue review processes and unduly prescriptive oversight, while also providing incentives to perform."[66] The formula rate plan is very comprehensive in scope (i.e., it applies to ComEd's entire rate base) and includes performance requirements (and penalties if standards are not met). We include ComEd in our case study panel because it can be considered an alternative example of incentives. Specifically, ComEd was hesitant to make the investments in grid modernization because of its magnitude and the possibility that it would not realize its authorized return, due to regulatory lag and/or disallowance. The formula rate approach has largely removed these concerns. As we noted earlier, however, the "incentive" to invest is via the mitigation of risk, more so than through a framework that balances rewards and risks.

66 Ross Hemphill and Val Jensen, "Illinois Approach to Regulating Distribution Utility of the Future," *Public Utilities Fortnightly*, June 2016.

VI. Authority and Compliance

Implementing performance or incentive based ratemaking involves some level of modification to the traditional C-o-S regulatory framework. For example:

- MRPs may involve formulaic annual adjustments to rates that are independent of the utility's actual costs;
- TPIs (e.g., EE and New York's EAMs) may involve incentive payments that are also independent of cost; and
- Formula rates may automatically update revenue requirements and/or adjust rates without a formal rate case review.

The process under which these changes varies considerably by jurisdiction depending mainly on the legal authority provided to state regulatory commissions as well as the commission's inclination for instituting change.[67] For example, the NYPSC has relatively broad authority to implement regulatory frameworks and has demonstrated a keen interest in positioning itself as a leader in regulatory innovation.[68] As a result, they have implemented MRPs with ARMs, traditional TPIs and a range of riders/trackers. In addition, their legal authority has extended to implementation of a new set of asymmetrical upward TPIs that are tied to policy goals (i.e., EAMs).

In sharp contrast, other state commissions (e.g., Florida, Minnesota and Michigan) require specific authority to modify the traditional C-o-S framework. Specific legislation was required in order for the Minnesota Public Utilities Commission (MPUC) to implement MRP with respect to the State's utilities. Furthermore, still additional legislation was needed before the Commission could extend the term of the MRP from three years (granted under the initial legislation in 2011) to five year (granted under legislation in 2015).[69]

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67 We have not conducted a legal analysis this matter nor, as an economics consulting firm, is The Brattle Group qualified to do so.

68 REV's major Ratemaking Order (NYSPSC Ratemaking Order, 2016) notes that legal constraints shape it's ratemaking but points to Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); Abrams v. Public Service Commission of the State of New York, 67 N.Y.2d 205, 214-15 (1986); and New York State Council of Retail Merchants v. Public Service Commission of the State of New York, 45 N.Y.2d 661, 668 (1978) to support the wide discretion in the methods Public Service Law grants the Commission to satisfy its mandate.

69 Minnesota statute § 216B.16, subd. 19, available at: https://www.revisor.mn.gov/statutes/?id=216b.16

Similarly, implementation of formula rates in Illinois required passage of Public Act 97-0616, which addressed regulatory stability (for utilities). The Act also authorized spending on infrastructure and established measures under which utilities will be held accountable for delivering benefits to customers. The legislation also included a specific timeframe under which the change from the traditional ratemaking process would be allowed. ComEd's formula rates were scheduled to be in effect until 2019, until Illinois Senate Bill 2814 extended the formula rate plan until 2022.

Once in place, PBR plans are typically intended to reduce the requirements associated with rate cases. However, they also are accompanied by their own reporting requirements. For example:

- MRPs with ARMs require calculation and review of annual rate adjustments;
- ESMs require calculation of ROEs and determination of whether and how any variance from authorized levels should be shared with ratepayers;
- TPIs involve tracking and reporting performance measures and determining any variance from targeted levels, and whether it triggers penalties;
- Multi-year formula rate plans (e.g., Illinois) and involves calculating annual revenue requirements and rates as well as associated performance requirements; and
- Capex riders/trackers (e.g., PSE&G) involve reviews of spending against plans and determination of performance against requirements.

It is clear that PBR has created its own set of reporting and compliance requirements. However, it is nearly impossible to quantify whether these requirements place a greater (or lesser) burden upon either utilities or Commission Staff. Staffs have limited capacity (in terms of work hours), so the change in requirements may cause a shift in focus rather than an increase (or decrease) in work. Estimating the impact on utilities is equally challenging. The MPUC considered the time spent by utilities and regulators to manage the various cost rider/tracker mechanisms, and concluded that "whether rates are higher or lower because of the existence of special recovery mechanisms remains a difficult question to answer precisely."[70]

[70] "Report To The Legislature: Utility Rates Study as Required By Laws of Minnesota, 2009, Chapter 110," submitted by the MPUC, June 2010.

VII. Findings and Conclusions

1. Most of the regulatory frameworks that we considered to be PBR are composed of combinations of incentive elements, and may not fit neatly into a "pure play" category. More typically, regulatory frameworks are usually based on traditional C-o-S regulation combined with a prescribed duration between rate cases (i.e., an MRP). In addition, however, the overall regulatory framework may also include performance incentives targeted on specific areas of utility performance or policy outcomes and/or specialized riders/trackers. As such, many regulatory frameworks have been classified as PBR in various studies, but not necessarily specified as PBR by the associated utility or regulatory agency.

2. MRPs tend to be the foundational element of many PBR plans, and provide incentives to utilities by enabling them to outperform expectations concerning cost incurrence thereby increasing earnings. MRPs are thus a formalization of the regulatory lag inherent under traditional C-o-S regulation where, once set in the rate case, rates continue unchanged until either customers or the utility requests a new rate case. All of the regulatory frameworks that we consider to be PBR thus include an MPR dimension. MRPs with annual adjustments (i.e., stair-step trajectories or I-X indexes) are largely indistinguishable from plans labeled as I-X (i.e., price and revenue cap).

3. MRPs can be combined with narrowly-based incentives (i.e., TPIs) and other regulatory mechanisms which provide supplemental incentives and/or mitigate risks associated with major capital programs or areas in which cost increases cannot reliably be foreseen and/or are not controllable by the utility. The combination of MRPs with adjustment mechanisms and other supplemental regulatory mechanisms more appropriately define whether a regulatory framework should be considered PBR, more so than does labeling by either the involved regulators or industry analysts.

4. The more "ambitious" PBR frameworks have been applied outside of the U.S., such as in Great Britain, Australia and Canada. Great Britain's RIIO holds the highest profile position, which may explain why Michigan's PA 341 includes references to RIIO and totex as PBR options. In many regards, the price and revenue cap plans in place in Alberta and Ontario, respectively, are similar to the above described MRPs with adjustment mechanisms, albeit with longer durations (i.e., five years versus, say three years between rate cases in California). Great Britain's RIIO approach stands alone from most other plans reviewed in terms of the comprehensiveness of its approach the duration of the plan (eight years). It is also a primary example of how individual elements (e.g., I-X and TPIs) can be combined, by way of a collaborative stakeholder process, to produce a tailored PBR plan.

5. TPIs are a widely applied and pervasive form of incentive regulation in the U.S. Historically, TPIs have been mainly applied to traditional areas of utility operations, such as reliability and customer service. Most of these TPIs have been designed in an asymmetrical downward fashion (that is, penalty-only) suggesting an implicit assumption that performance targets have been set at the equilibrium point between marginal cost and marginal benefit. That is, asymmetrical downward TPIs implicitly assume that achieving higher levels of, for example, reliability cost more than it is worth to customers. However, the TPI frameworks that are being applied to policy goals (such as emissions reductions, system efficiency and DER integration) tend to be asymmetrical upward (i.e., rewards only). Though there are few examples (notably in New York), where these new TPIs areas are set up asymmetrically upward (i.e., reward only). That is, regulators implicitly assume that the marginal benefits associated with achieving these goals exceed the costs of achieving them (i.e., their marginal costs).

6. "Totex," has received considerable attention as an element of PBR but, to our knowledge has not been implemented in the U.S. yet. Consideration of applying a totex approach in the U.S. has sometimes been wrapped together with the application of RIIO overall. However, it is only one element of the RIIO framework and can be applied independently by itself. It should be noted, however, that implementation of the totex concept will be accompanied by some accounting challenges. The New York PSC concluded that "differences in accounting standards between the United Kingdom and the United States would complicate efforts to import the totex approach here," and put off implementing totex until it studied the issue further. Nonetheless, we expect to see totex, or variations upon it, to be seriously considered and applied in leading jurisdictions in the near future.

7. The roles of incentives and performance within a PBR framework deserve clarification and emphasis as part of this benchmarking study. It is widely understood that incentive regulation and/or performance based regulation (terms that are typically used interchangeably) refer to a regulatory framework that motivates utilities to improve their performance through the application of incentives beyond those found in traditional cost-of-service regulation. However, the form of incentive and performance, as well as associated performance requirements, varies by PBR element.

   The incentives included in PBR may be either broad in nature or more narrowly aligned with specific outcomes. Broad incentives, mainly to control costs, are included in the overall MRP mechanism. By operating at a more efficient level (i.e., controlling costs) utilities are able to realize higher earnings than would otherwise be the case. The increased period of time between rate cases provides a financial benefit; that is, if the utility is successful in controlling costs.

Outcome focused incentives are exemplified by TPIs. Traditional TPIs include incentives to maintain (or improve) performance with respect to service quality metrics. The structure of incentives that are applied to traditional TPIs are typically more "stick than carrot" in that they are frequently asymmetrical downward; e.g., failure to meet service level targets will result in a loss of earnings. We refer to TPIs that are aligned with specific policy goals (e.g., integration of DERs) as "emerging" TPIs. The incentives associated with these TPIs are designed to motivate utilities to shift behavior in ways that support new policy and less traditional goals, and therefore tend to be asymmetrical upward.

An additional, and important, area of outcome based incentives concerns grid maintenance, upgrades and modernization. MRPs, by themselves, do not provide utilities with specific incentives to invest in large projects, especially if they need to be completed on an expedited basis. Furthermore, making such significant investments may be in conflict with the incentive to control cost that is inherent in the MRP plan. In response, Commissions sometimes implement a formula rates (e.g., ComEd) or capex riders (e.g., PSE&G) which permit revenues to increase on a formulaic basis contingent on the utility making investment over the plan term. These mechanisms provide some assurance that utilities will not suffer the negative effects of regulatory lag with respect to rate base growth, thereby reducing risk and motivating utilities to invest in grid infrastructure.

The various PBR plans that we include in this study emphasize all or a subset of these incentive elements. The RIIO framework incorporates all three forms of incentives, as does the overall regulatory framework that is applied to Con Edison. Fewer incentives are incorporated into other plans. For example, MRPs by themselves (i.e., without TPIs or capex riders/trackers) are applied to FPL and NSP, while a specific, albeit large, capex rider/tracker is applied to PSE&G (i.e., the ESAM) without an MRP.[71]

8. Regulatory frameworks, in general, also incorporate performance standards concerning acceptable levels of service (e.g., reliability and customer service). In addition to having broad authority to regulate service quality, most, if not all, state commissions require that utilities report their performance against specific measures.[72] As we indicated earlier in

[71] In practice, PSE&G has gone 7 years since its last rate case. The utility is scheduled to submit a rate case later in 2017. Its last rate case was approved in 2010.

[72] At least 37 states have performance reporting and/or TPIs in place. "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," O'Neil Management Consulting LLC , December 13, 2012

our report, some but not all regulators have also incorporated explicit performance requirements and associated financial incentives (mainly penalties) as part of the ratemaking framework. For example, six of the 11 utilities included as case studies have TPIs as part of their frameworks. Regulators have relied upon broader authority and/or reporting requirements to assess utility performance, and take action as needed, with respect to the remaining five case study utilities.

Performance improvements resulting from investments made via capex riders/tracker will likely take time to materialize.[73] Thus, performance requirements associated with capex riders/trackers tend to focus on investment schedules and target areas, rather than on more conventional performance metrics. For example, the New Jersey BPU approved an adjustment mechanism (i.e., the ESAM) for PSE&G to recover $1 billion of the utility's investment made in its Energy Strong program.[74] The BPU checks the PSE&G's performance in terms of spending in the agreed upon areas prior to incorporating costs into the ESAM. In addition, the BPU requires that PSE&G report certain areas of performance although there are no penalties associated with failure to meet specific targets.[75] The areas of reporting include Customer Average Interruption Duration Index (CAIDI) Major Event performance on a circuit, operating level and system wide basis. PSE&G also needs to report its progress in reducing its active leak inventory associated with its natural gas infrastructure.

The Illinois Commerce Commission (ICC) has taken a slightly different approach to ComEd's ratemaking framework. Similar to the approach taken in New Jersey, the Commission reviews and approves ComEd's revenue requirements before incorporating

73 Unless addressing a specific area of deficiency, in which case improvements in, say, reliability may be observable in the short term.

74 Total investment approved for the Energy Strong project was $1.22 billion ($620 million to raise substations; $350 million to replace and modernize 250 miles of gas mains; $100 million to create system redundancy; $100 million to deploy smart grid; and, $50 million to protect gas metering stations and a liquid national gas (LNG) station). $1 billion is recovered via the ESAM. The remaining $200 million will be recovered as part of a base rate case (to be filed no later than November 2017).

75 With the exception of continued failure to meet targets concerning reducing active leak inventory. Specifically, "If the Company fails to reduce leak inventory by 10% annually two years in succession, the Company shall achieve compliance with this obligation without seeking cost recovery for the incremental expense from ratepayers" See NJ BPU, "In The Matter of the Petition of Public Service Electric and Gas Company for Approval of Electric and Gas Base Rate Adjustments Pursuant to the Energy Strong Program," Docket Nos. EO13020155 and GO13020156, March 21, 2014, p. 19. Additional details for PSE&G ESAM capex rider/tracker is included in Appendix B-5.

them into the formula rate mechanism. However, the ICC has also used its formula rate mechanism to introduce TPIs into its regulatory framework. In this case, failing to achieve specific performance targets is tied to the return on equity allowed in the formula rate calculation, rather than creating a separate and stand-alone TPI mechanism.

9. A logical first step in developing a regulatory framework for utilities in Michigan (and, for that matter, in general) involves specifying the issues of concern. Some of the issues and elements identified in Michigan's PA 341can only be met through PBR elements (e.g., increasing the length of time between rate cases) while others can be met through PBR as well as through other options (encouraging utilities to invest in projects with long pay-backs). The issues and elements cited in PA 341 and the associated regulatory options are summarized in Table 5 below.

Table 5: PBR Options to Meet Elements Identified in PA 341

Michigan Legislation	Related PBR Mechanisms
Multi-year periods; increase the length of time between rate cases	MRPs (price caps, revenue cap) Stair step adjustments, I – X
Encourage utilities to make investments that have extended payback periods	Riders/Trackers, Formula rates
Totex	Totex or variations thereon
Targeted performance areas (e.g., customer satisfaction, reliability)	PIMs
Profit sharing	ESMs, regulatory assets

Following from the options included in the table:

– Increasing the time period between rate cases, which we found to be the foundation of PBR, can be met through several varieties of MRPs.

– Encouraging utilities to invest in projects with long-term pay-backs (e.g., grid modernization) can be accomplished through capex riders/trackers (e.g., PSE&G) or formula rates (e.g., ComEd), either on a stand-alone basis or as part of an integrated PBR plan.

– Encouraging utilities to make spending decisions that minimize total costs (addressing any perceived bias towards capital based solutions) can be accomplished through various adjustments to the ratemaking process. However, the totex approach is the most direct.

– Holding utilities accountable to performance standards can be accomplished with TPIs, which are typically specified as stand-alone mechanisms. (We, and others, do not include performance requirements tied to capex riders/trackers or formula rates to be TPIs.) As is the case with capex riders/trackers and formula rates, TPIs can also provide an important dimension of an integrated PBR framework.

– Profit sharing can be accomplished through specific earnings sharing mechanisms, however it is also inherent in PBR plans through the resetting of rates at the end of the MRP. That is, if a utility "saves" a dollar (i.e., reduces its revenue requirement through improving its operating efficiencies), it doesn't get to keep that forever, just until the reset at the next rate case.

10. In conclusion, we are drawn back to the graphic of regulatory "pure play" options on an incentive vs. risk/reward matrix (repeated below).

Figure 3: PBR Frameworks on a Risk and Reward Scale

As indicated earlier, the scale of incentives and risk/reward are illustrative (i.e., does not represent specific quantitative ratios) in the above diagram. Moreover, the placement of a plan type (e.g., MRPs) in the above matrix may vary greatly depending on plan design and specification. For example, an MRP with eight years between resets would have greater potential for risk/reward, and stronger incentives, than an MRP with three years between resets, even if all the other features of the two plans were the same. That is, longer term plans provide the opportunity for the affected utilities to retain the results of successful cost control efforts. However, such a plan by itself may not provide incentives for utilities to invest in projects with long paybacks.

We also highlight the position of traditional C-o-S regulation combined with formula rates and/or capex riders/trackers. As discussed throughout our report, these mechanisms tend to mitigate the risks of under-recovery and under-earning, making it more attractive to invest in projects with long-term paybacks. They also modify incentives to control costs (since the potential for over-earning is also significantly reduced). While motivating utilities to invest in the projects covered within the scope of the formula rate or capex rider/tracker plan, it may also de-motivate investments outside the scope.

However, a key take-away from our review and analysis is that the pure play plans depicted in the above graphic rarely exist in isolation. Instead, they are part of a larger framework that is, ideally, thoughtfully integrated in a way that balances overall incentives, reward and risk.

11. Effective PBR plan designs should be based on objectives and priorities set out by policy makers, Commissions and other stakeholders. For example, when the Alberta Utilities Commission set out to transition the electric and gas utilities in Alberta from traditional C-o-S regulation to five-year PBR plans, the first step was to propose and agree on a set of PBR principles:[76]

   - A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality;
   - A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return;
   - A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time;
   - A PBR plan should recognize the unique circumstances of each regulated utility that are relevant to a PBR design; and,
   - Customers and utilities should share the benefits of a PBR plan.

   Proceedings concerning PBR frameworks are frequently initiated in response to specific issues, problems and/or policy goals, which may strongly influence plan emphasis and design. In Alberta, the focus was on improving efficiencies and controlling costs, which led their PBR framework towards a five-year plan with I – X adjustments. In contrast, in Hawai‘i, the Public Utilities Commission raised concerns about the slow pace of renewable integration by the Hawaiian Electric Companies (HECO),[77] including customer-owned PV systems, as well as the frequency or requests for rate increases.[78] In response, the Commission adopted a formula rate plan, designed to provide incentive to HECO to invest in needed system upgrades and strengthening (to accommodate high growth rates in sales) and to provide for timely revenue recovery for capital investments made between rate cases.

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76 See AUC Bulletin 2010-20, “Regulated Rate Initiative – PBR Principles,” July 15, 2010, pp. 2-3.

77 The Hawaiian Electric Companies include Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawai‘i Electric Light Company, Inc.

78 Commission’s Inclinations on the Future of Hawai‘i’s Electric Utilities, Aligning the Utility Business Model with Customer Interests and Public Policy Goals, Exhibit A to Decision and Order No. 32052, issued April 28, 2014, in Docket No. 2012-0036.

12. Accordingly, the PBR plans actually implemented in different jurisdictions reflect the policy priorities of that jurisdiction and the specific circumstances of the utilities there, and thus often do not neatly fit into pre-defined labels or categories. Such labeling is a necessary step in conducting benchmarking studies but, overall, we do not find this practice to be particularly helpful in determining what kind of plan would be best suited to a particular utility or particular set of circumstances. Rather, the designers of PBR frameworks should focus on the key dimensions that we introduced earlier, and summarize below.

   - The term of the plan, meaning the period of time between one rate case and the next, is crucial because it largely determines the strength of incentives to control costs. The longer is the time between rate reviews, the greater the opportunities for the utility to realize additional earnings by performing above expectations (and also the greater the chance for losses if the utility performs below expectations). We find that PBR plans range in length from three to eight years, with five being common (albeit outside the U.S.).
   - The scope of the plan, meaning what activities and associated costs are included within the revenues determined by the PBR plan, and what activities are outside. Activities outside the PBR plan are funded instead by riders/trackers or other mechanisms which update revenue according to how recorded costs change during the plan term. In contrast, activities within the scope of the plan are funded by PBR revenues which may adjust during the plan term (e.g., following I – X) but do not update to reflect changes in recorded costs until the end of the plan term. Activities within the scope of the plan see the strengthened incentives of PBR while activities outside the plan do not. Some PBR plans are comprehensive, covering all utility activities and costs, while others may focus on specific activities or categories of cost (e.g., O&M only).
   - Revenue or rate adjustment during the plan term: some plans have no adjustment (equivalent to a rate freeze), while others may adjust for changes in inflation or may have pre-determined "step changes" each year. Periodic (e.g., annual) rate/revenue adjustments enables better alignment with expected costs; this revenue adjustment allows for a longer plan term, and therefore stronger incentives. The method of adjusting revenue itself, however, has no impact on incentives. Only if changes in recorded costs were to influence revenue adjustments before the end of the plan term would incentives be weakened (as in a rider/tracker or rider/tracker mechanism).
   - Outputs of various kinds can be measured and can drive additional financial rewards or penalties as part of a PBR plan. Such TPIs have traditionally been used to target distribution network reliability and customer service (call center response times). Other outputs can also be measured, such as quantity of renewable generation connected to the distribution network. Emerging TPIs are being developed to

encourage utilities to contribute to achieving various policy goals such as renewables, distributed energy resources, and EE.

List of Acronyms

Acronym	Definition
AER	Australian Energy Regulator
Alagasco	Alabama Gas Company
AMI	Advanced Metering Infrastructure
APCo	Alabama Power Company
ARMs	Attrition relief mechanisms
AUC	Alberta Utilities Commission
CAC	Capital adjustment clause
CAIDI	Customer average interruption duration index
Capex	Capital expenditures
CIIP	Capital Infrastructure Investment Program
ComEd	Commonwealth Edison Co.
Con Edison	Consolidated Edison Co. of NY
C-o-S	Cost of Service
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
D.C.	District of Columbia
DERs	Distributed energy resources
DPU	Massachusetts Department of Public Utilities
DRA	Division of Ratepayer Advocate
DSM	Demand side management
EAMs	Earning adjustment mechanisms
EE	Energy efficiency

EEI	Edison Electric Institute
EIMA	Energy Infrastructure Modernization Act
EO	Energy optimization
EPC	ENMAX Power Corporation
ESAM	Energy Strong Adjustment Mechanism
ESMs	Earnings sharing mechanisms
EVT	Efficiency Vermont
FAC	Fuel adjustment clause
FEJA	Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light
FPSC	Florida Public Services Commission
GRC	General rate case
HECO	Hawaiian Electric Companies
I-Factor	Inflation factor
IBR	Incentive-based ratemaking
ICC	Illinois Commerce Commission
ICE	Incentive on Connections Engagement
IQI	Information Quality Incentive
K-Factor	Capital tracker
IRM	Innovation roll-out mechanism
LNG	Liquid natural gas
LPP	Leak prone pipe
MPUC	Minnesota Public Utilities Commission

MRP	Multi-year rate plan
MWBE	Minority-owned and women-owned business enterprises
NEL	National Electricity Law (Australia)
NGN	Northern Gas Networks (U.K.)
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NJ BPU	New Jersey Board of Public Utilities
NPg	Northern Powergrid (U.K.)
NRRI	National Regulatory Research Institute
NSP	Northern States Power (Xcel Energy)
NWA	Non-wire alternatives
NYPSC	New York Public Service Commission
O&M	Operation and maintenance
Ofgem	U.K. Office of Gas and Electricity Markets
OGE	Oklahoma Gas & Electric Company
Opex	Operating expenditures
PACT	Program administrator cost test
PBR	Performance-based regulation or performance-based ratemaking
PCT	Participant test
PG&E	Pacific Gas and Electric Company
PSE&G	Public Service Electric & Gas
PUC	Public Utilities Commission
PV	Photovoltaic
QPIs	Quantifiable performance indicators

RES	Renewable energy standard
REV	Reforming the Energy Vision
RIIO	Revenue = incentives + innovation + outputs
RIM	Rate impact measure
ROE	Return on equity
RPI	Retail price index
RSE	Rate stabilization and equalization
SAIDI	System average interruption duration index
SCE	Southern California Edison
SCT	Societal cost test
SDG&E	San Diego Gas & Electric Company
SGRF	Smart Grid Rider/Tracker Factor
SNL	SNL Energy Research, division of S&P Global Market Intelligence
SPVP	Solar PV Program
SPVPBA	Solar PV program balancing account
T&D	Transmission and distribution
Totex	Total expenditures
TPIs	Targeted performance incentives
TRC	Total resource cost test
UoF	Utility of the future
X-Factor	Productivity offset set in a PBR period
Y-Factor	Adjustment to account for certain flow-through costs (Alberta)
Z-Factor	Adjustment to account for the effect of exogenous events (Alberta)

BOSTON
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME
SYDNEY

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Appendix A: Survey of PBR / Incentive Regulation in the U.S.

This appendix provides "counts" and other information on various types of regulatory frameworks currently in place in the U.S. that we consider to be PBR or incentive regulation. These include:

Appendix A-1: Survey of Multi-year Rate Plans
Appendix A-2: Survey of US Traditional TPI Plans
Appendix A-3: Summary of Traditional TPI Measures – System Reliability
Appendix A-4: Summary of Traditional TPI Measures – Customer Service and Employee Safety
Appendix A-5: Survey of Energy Efficiency TPIs

We also include regulatory plans that are frequently implemented in conjunction with PBR and/or regulatory incentive frameworks. These include:

Appendix A-6: Survey of U.S. Formula Rate Plans
Appendix A-7: Survey of Utility Riders/Trackers

The data underlying the tables included in the appendix are based on a range of surveys and studies conducted by industry organizations (e.g., Edison Electric Institute, or EEI), utilities, regulatory staffs and research arms, industry analysts and consultants, as well as Brattle's own primary research.

There are hundreds of electric and gas utilities that are regulated by 51 state (and the District of Columbia) regulatory commissions in the U.S., which are involved in an almost continuous stream of reviews and proceedings. The status of the various regulatory frameworks included in the following tables may not be completely current. In addition, as indicated in the introduction to the accompanying report, the definition of PBR "labels" frequently differs, sometimes substantially, from one survey or study to another.

Brattle applied considerable diligence to our review and compilation of these data. Nonetheless, because of the changing nature of regulatory plans and approaches and potential inconsistencies concerning classifications and other representations made in the various surveys and studies considered, we attach a strong caveat to this appendix. Specifically, the information included in this appendix should be considered with the appropriate level of understanding concerning sources and should be used with an appropriate level of caution.

Appendix A-1: Survey of U.S. Multi-year Rate Plans

States	Utilities	ARM?	Utilities with MRPs Programs (by State)	Earnings Sharing Provision
Arizona	Arizona Public Service Arizona Gas	No	2	None
California	California Pacific Electric Pacific Gas and Electric San Diego Gas and Electric Southern California Edison Southern California Gas Southwest Gas	Yes	6	None
Colorado	Public Service of Colorado Black Hills Gas Distribution	No	2	Sharing of overearnings only up to earnings cap
Connecticut	United Illuminating (UI) Connecticut Natural Gas (CNG) Southern Connecticut Gas (SCG)	No	3	N/A
Florida	Duke Energy Florida Florida Power and Light Gulf Power Florida Public Utilities Tampa Electric	Both	5	None
Georgia	Georgia Power	Yes	1	Sharing of overearnings only with deadband
Hawaii	Hawaiian Electric Company Hawaiian Electric Light Company Maui Electric	Yes	3	Sharing of overearnings only without deadband, multiple sharing levels
Idaho	MidAmerican Energy Pacificorp	Yes	2	Sharing of overearnings only with deadband up to earnings cap
Indiana	Northern Indiana Public Service Company	No	1	Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less
Illinois	People Gas Light Coke/ North Shore Gas	No	1	N/A
Iowa	Mid American	No	1	N/A
Kansas	Atmos Energy Kansas Gas Service	No	2	N/A
Louisiana	Cleco Power Entergy New Orleans	No	2	Sharing of overearnings only with deadband up to earnings cap
Maine	Summit Natural Gas of Maine	Yes	1	None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband
Massachusetts	Bay State Gas Berkshire Gas (BG) Liberty Utilities (New England Natural Gas)	No	3	None
Michigan	Wisconsin Public Service	Yes	1	N/A
Montana	MDU Resources	Yes	1	N/A
Nebraska	Black Hills Gas Distribution	No	1	N/A
New Hampshire	Northern Utilities Public Service Company of New Hampshire Unitil Energy Systems	Yes	3	NU - Sharing of overearnings only with deadband up to earning cap PSCNH/Until Energy - Sharing of overearnings only with deadband
New Mexico	New Mexico Gas (NMG)	No	1	N/A
New York	Consolidated Edison New York State Electric and Gas Orange and Rockland Utilities Rochester Gas and Electric	Yes	4	ConEd - Sharing of overearnings only with deadband and multiple bands Orange and Rockland Util. - Sharing of overearnings only with deadband and multiple sharing bands
North Dakota	Northern States Power - Minnesota	Yes	1	Sharing of overearnings only without deadband, earnings adjusted for effects of weather
Ohio	Ohio Power Cleveland Electric Illuminating Ohio Edison Toledo Edison	No	4	N/A
Pennsylvania	Peoples Natural Gas, Equitable Gas Pike County Light and Power (PCLP)	No	2	N/A
South Dakota	Northern States Power- Minnesota NorthWestern Corp	No	2	N/A
Virginia	Appalachian Power Virginia Electric Power	No	2	N/A
West Virginia	Equitable Gas Appalachian Power (APCO)/Wheeling Power (WP)	No	2	N/A
Wisconsin	Wisconsin Electric Power (WEPCO) Wisconsin Gas (WG) Wisconsin Power and Light	No	3	N/A
		Total Mechanisms	62	

Source: "Rate Freezes: Their Historical Context and Prevalence Today," SNL Regulatory Research Associates, August 2016; and "Alternative Regulation for Emerging Utility Challenges: 2015 Update," Pacific Economics Group for the Edison Electric Institute, November 11, 2015. **NOTE:** We include Northern States Power (Xcel in Minnesota) in our list of MRP. It is not included in the EEI survey because NSP's MRP began in 2016 (the EEI report was released in 2015). Similarly, because we combined two data sources, states with N/A in the ESM column are those that were not in the EEI report (which provided ESM data) but were captured in SNL's count.

Appendix A-2: Survey of US Traditional TPI Plans, Some of Which Involve Penalties

States	Title	Types of TPIs Metrics (by State)
Colorado	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission	4
Delaware	Reliability and Safety Worst Circuits Complaints to the Commission Appointments Kept	4
Illinois	Reliability and Safety Worst Circuits	2
Louisiana	Reliability and Safety Telephone Answering	2
Maine	Reliability and Safety Telephone Answering Complaints to the Commission Appointments Kept Satisfaction	5
Maryland	Reliability and Safety Worst Circuits	2
Massachusetts	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission Metering Reading Appointments Kept Satisfaction	7
Minnesota	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission	4
Mississippi	Reliability and Safety Satisfaction	2
New York	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission Metering Reading Appointments Kept Satisfaction	7
Oregon	Reliability and Safety Worst Circuits Complaints to the Commission	3
Rhode Island	Reliability and Safety Worst Circuits Telephone Answering Metering Reading Satisfaction	5
Texas	Reliability and Safety Worst Circuits Telephone Answering Appointments Kept	4
Utah	Reliability and Safety Worst Circuits	2
Vermont	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission Metering Reading Appointments Kept Satisfaction	7
Washington	Reliability and Safety Worst Circuits Telephone Answering Complaints to the Commission Appointments Kept Satisfaction	6
	Total Mechanisms	66

Source: "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," O'Neil Management Consulting LLC , December 13, 2012. The original data from this report includes TPIs with penalties for Michigan. Upon close inspection we don't believe they are applicable and removed that data from the table.

Appendix A-3: Summary of Traditional TPI Measures – System Reliability

Type	Metric	Definition	Measurements Level
Outages	System Average Interruption Duration Index (SAIDI)	The minutes of customer interruption divided by the total number of customers served by the distribution system, expressed in minutes per year.	• On total system basis • Disaggregated by system configuration (network vs. radial)
Outages	System Average Interruption Frequency Index (SAIFI) Measures	The frequency of customer interruption divided by the total number of customers served by the distribution system, expressed in interruptions per year.	• By geography and/or • Feeder group or individual feeders.
Outages	Circuit Average Interruption Duration Index (CKAIDI)	Total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year.	• On a total system basis • Penalties can be based on worst circuit only
Outages	Circuit Average Interruption Frequency Index (CKAIFI)	Total frequency of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in interruptions per year.	• On a total system basis • Penalties can be based on worst circuit only
Outages	Customer Average Interruption Duration Index (CAIDI)	Total minutes of customer interruptions divided by the total number of customers, expressed in minutes per year.	• On total system basis • Disaggregated by system configuration (network vs. radial)
Outages	Customer Average Interruption Frequency Index (CAIFI)	Total frequency of customer interruptionsdivided by the total number of customers, expressed in interruptions per year.	• By geography and/or • Feeder group or individual feeders.
Outages	Major Outage Metric	Number of outages causing a percentage of customers to lose power over a specified time period.	• Disaggregated by system configuration (network vs. radial)
Outages	Restoration Peformance Metric	Targets for time to restore service following outages of overhead system.	• Measured at storm levels, e.g. "upgraded," "serious," and "full scale" outage events
Power Quality	Power Quality	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker.	• Varies
Infrastructure	Damaged Poles Repairs	Percentage of poles replaced within or outside of a set time frame, such as 30 days, starting from the day the company is aware of the damage.	• Measured system wide by year.
Infrastructure	Poor Performing Circuits List	Any distribution feeder that possesses a CKAIDI or CKAIFI value(s) among the highest (worst)percentage, such as 5%, for any two consecutive reporting years.	• Meaured at feeder level • Can be second tier, meaning only activated if SAIDI -SAIFI is within the deadband
Infrastructure	Replacement of Over-Duty Circuit Breakers	Specifes a target count of over-duty circuit breakers be replaced with a rate year. Over-duty circuit determined by applying the highest of the three faults (i.e.: three phase, double-line to ground, and single-line to ground faults) was compared against the respective station lowest circuit breaker rating.	• System wide
Infrastructure	Removal of Temporary Shunts (temporary electrical cable or conduit)	Targets that a high percentage (such as 90%) of shunts installed during the calendar year be removed within 45-90 days. Days allowed for removal can be dependent on season with fewer days allowed during summer.	• System wide
Infrastructure	Remote Monitoring System	Requires the company maintain a high rate of reporting (such as 90%) across a network.	• Can be measured quarterly or monthly • Measured at network level (such as second contingency level) • Extraordinary circumstances can be taken into account when examining performance
Infrastructure	Repair of Current Street Lights and Traffic Signals	Targets that a high percentage (such as 90%) of lights or signals that come into existence during the calendar year be removed within 45-90 days. Days allowed for removal can be dependent on season with fewer days allowed during summer.	• System Wide
Gas	Class I / Class II Gas Odor Calls	Related to Gas Companies- number of calls that relate to a strong odor (Class I) or slight odor (Class II) of gas throughout a household or outdoor area, or a severe odor from a particular area. Requires a high percetage of calls, such as 95%, occur within a set time frame, such as one hour.	• System Wide

Sources: "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," O'Neil Management Consulting LLC , December 13, 2012; "Utility Performance Incentive Mechanisms," Synapse, March 9, 2015; and "Consolidated Edison Company of New York, Inc. Report on 2009 Performance under Electric Service Reliability Performance Mechanism, Distribution Engineering Department, Consolidated Edison Company of New York, Inc., March 31, 2010.

Appendix A-4: Summary of Traditional TPI Measures – Customer Service and Employee Safety

Type	Metric	Definition	Measurement Level
Customer Service and Billing	Avoided Shutoffs and Reconnections	Disconnects and reconnections avoided by customer as percentage of income payment plans or other means	• System wide
Customer Service and Billing	Billing Accuracy or Billing Adjustments	Billing adjustments needed per set number of customers, such as per 1,000 customers.	• Measured annual per utility
Customer Service and Billing	On-Cycle Meter Reads	Percentage of meters that are actually read by the Company.	• Measured by utility- both residential and commercial combined • Measured monthly- usually reported annually
Customer Service and Billing	Service Appointments Kept or Missed Appointments	The percentage of scheduled service appointments met by Company personnel on the same day requested. Can also be measured as percentage of appointments not met when customer must be present for visit. Collected monthly and reported yearly.	• Measured annual per utility
Customer Service and Billing	Outage Notifications	Specified levels of simultaneous customer outages per hour, such as 70,000 customers for one hour, trigger need for communications, such as notification to the Office of Emergency Management .	• Outage event can be considered single load area or multiple load areas
Customer Satisfaction	Customer Survey	Could survey emergency calls, all calls, transaction specific surveys, or visitors to Service Centers	• Varies • JP Power Overall Customer Satisfaction Index available by Company grouped by Region (East, Midwest, South, West) and Segment (Large and MidSize Companies).
Customer Satisfaction	Telephone Service Factor or Call Answer Rate	Usually based on the percentage of calls handled within a target time frame, for example- 20 or 30 seconds.	• System wide
Customer Satisfaction	Transaction Satisfaction Target	Can be measured in the form of Customer Satisfaction Surveys or data on customer complaints. Can also be measured using Satisfaction Index from J.D. Power Electric Utility Residential Customer Satisfaction Study, J.D. Power Gas Utility Residential Customer Satisfaction Study.	• Can be measured at residential or commercial class.
Customer Satisfaction	Commission Complaints	Formal complaints to the Commission per set number of customers, such as per 1,000 customers.	• Limited to jurisdiction of PUC
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	• Reported within OSHA Form 300 for electric • Reported within PHMSA Form F 7100.1 for Gas
Employee Safety	Lost Work Time Accident Rate	Hours of lost work time from injuries and illness per 200,000 Employee Hours as defined by the U.S. Department of Labor Bureau of Labor Statistics.	• System wide
Public Safety	Emergency Response Time	Percent of electric emergency responses within a specified response time, such as 60 min, each year.	• System wide

Sources: "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," O'Neil Management Consulting LLC , December 13, 2012; "Utility Performance Incentive Mechanisms," Synapse, March 9, 2015; and "Consolidated Edison Company of New York, Inc. Report on 2009 Performance under Electric Service Reliability Performance Mechanism, Distribution Engineering Department, Consolidated Edison Company of New York, Inc., March 31, 2010.

Appendix A-5: Survey of Energy Efficiency TPIs

States	Type
Arizona	Shared Net Benefit
Arkansas	Shared Net Benefit
California	Multifactor Performance Mechanisms Overview
Colorado	Shared Net Benefit
Connecticut	Savings Based
DC	Multifactor Performance Mechanisms Overview
Georgia	Shared Net Benefit
Hawaii	Multifactor Performance Mechanisms Overview
Indiana	Savings Based
Kentucky	Shared Net Benefit
Massachuesetts	Multifactor Performance Mechanisms Overview
Michigan	Savings Based
Minnesota	Shared Net Benefit
Missouri	Shared Net Benefit
New Hampshire	Savings Based
New York	Savings Based
North Carolina	Shared Net Benefit
Ohio	Shared Net Benefit
Oklahoma	Shared Net Benefit
Rhode Island	Savings Based
South Carolina	Shared Net Benefit
Texas	Shared Net Benefit
Vermont	Multifactor Performance Mechanisms Overview
Wisconsin	Multifactor Performance Mechanisms Overview
New Mexico	Rate of Return
Total Mechanisms	25

Source: “Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency,” American Council for an Energy Efficient Economy, May 2015.

Appendix A-6: Survey of U.S. Formula Rate Plans

States	Utilities	Title	Formula Rates Mechanisms (by State)
Alabama	Alabama Power Alabama Gas Mobile Gas Service	Rate Stabilization & Equalization Factor (Rate RSE)	1
Georgia	Atmos Energy	Georgia Rate Adjustment Mechanism (GRAM)	1
Illinois	Ameren Illinois Commonwealth Edison (Com Ed)	Rate Modernization Action Plan - Pricing (Rate MAP-P)	1
Louisiana	Atmos Energy Southwestern Electric Power	Rate Stabilization Clause and Formula Rate	1
Mississippi	Atmos Energy Corp Centerpoint Energy Arkla Entergy Mississippi Mississippi Power	Stable/Rate Rider Rate Regulation Adjustment Rider Formula Rate Plan 6 (FRP-6) Performance Evaluation Plan (PEP-5)	4
Oklahoma	Centerpoint Energy Arkla Arkansas Oklahoma Gas	Performance Based Rate of Change Plan	1
South Carolina	Piedmont Gas South Carolina Electric and Gas	N/A	1
Tennessee	Atmos Energy	Annual Review Mechanism	1
Texas	Centerpoint Energy Texas Coast Divison Atmos Energy Mid Texas Division Texas Gas Service- Rio Grande Texas Gas Service- North Service Areas	Cost of Service Adjustment Clause Rate Review Mechanism Cost of Service Adjustment	3
Utilities Covered	17	Total Mechanisms	14

Source: “Alternative Regulation for Emerging Utility Challenges: 2015 Update,” Pacific Economics Group for the Edison Electric Institute, November 11, 2015. **NOTES:** EEI’s Definition of Formula Rates: A wide-scope cost tracker designed to help a utility’s revenue track its cost of service with earnings true-ups. Some FRP may include elements such as TPIs. Also, we do not count different service areas as separate utilities.

Appendix A-7: Survey of Utility Riders/Trackers

States	Utility	Type	Count of Utilities with Riders and Trackers
Alabama	Alabama Power Alabama Gas Mobile Gas	Purchased Power Environmental Compliance Decoupling Generation Capacity Capex Other	3
Alaska	Alaska Electric Light & Power Enstar Natural Gas	Purchased Power	2
Arizona	Arizona Public Service Southwest Gas Tucson Electric Power UNS Electric UNS Gas	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex RTO Expense Other	5
Arkansas	Arkansas Oklahoma Gas CenterPoint Energy Resources Entergy Arkansas Oklahoma Gas & Electric SourceGas Arkansas Southwestern Electric Power	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Infrastructure Capex RTO Expense Other	6
California	Pacific Gas & Electric San Diego Gas & Electric Southern California Edison Southern California Gas Southwest Gas	Purchased Power Decoupling	5
Colorado	Black Hills Colorado Electric Public Service Co. of Colorado Black Hills Gas- Distribution	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex Other	3
Connecticut	Connecticut Lt. & Pwr. Conn. Natural Gas Southern Conn. Gas United Illuminating Yankee Gas Service	Purchased Power Conservation Program Decoupling Infrastructure Capex RTO Expense	5
Delaware	Chesapeake Utilities Delmarva Power & Light	Purchased Power Environmental Compliance RTO Expense Other	2
District of Columbia	Potomac Electric Power Washington Gas Light	Purchased Power Decoupling Renewables Infrastructure Capex Other	2
Florida	Florida Power & Light Duke Energy Florida Florida Public Utilities Gulf Power Peoples Gas System Pivotal Utility Holdings Tampa Electric	Purchased Power Conservation Program Environmental Compliance Generation Capacity Capex Infrastructure Capex Other	7

Table continued on next page

States	Utility	Type	Count of Utilities with Riders and Trackers
Georgia	Atlanta Gas Light Georgia Power Liberty Utilities (Peach State Nat. Gas)	Purchased Power Decoupling Environmental Compliance Generation Capacity Capex Infrastructure Capex	3
Hawaii	Hawaiian Electric Hawaiian Electric Light Maui Electric	Purchased Power Conservation Program Decoupling Renewables Generation Capacity Capex Infrastructure Capex Other	3
Idaho	Avista Corp. Idaho Power PacifiCorp	Purchased Power Conservation Program Decoupling	3
Illinois	Ameren Illinois Commonwealth Edison MidAmerican Energy North Shore Gas Northern Illinois Gas People Gas Light and Coke	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex RTO Expense Other	6
Indiana	Duke Energy Indiana Indiana Gas Indidana Michigan Power Indianapolis Power & Light Northern Indiana Public Service Southern Indiana Gas & Electric	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	6
Iowa	Black Hills Iowa Gas Utility Interstate Power & Light MidAmerican Energy	Purchased Power Conservation Program Renewables Environmental Compliance Infrastructure Capex RTO Expense Other	3
Kansas	Atmos Energy Black Hills/Kansas Gas Utility Empire District Electric Kansas City Power & Light Kansas Gas & Electric Kansas Gas Service Westar Energy	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex RTO Expense Other	7
Kentucky	Atmos Energy Columbia Gas of Kentucky Delta Natural Gas Duke Energy Kentucky Kentucky Power Kentucky Utilities Louisville Gas & Electric	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex Other	7
Louisiana	Entergy New Orleans Atmos Energy CenterPoint Energy Res. (Arkla) Cleco Power Entergy Louisiana Southwestern Electric Power	Purchased Power Conservation Program Decoupling Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	6
Maine	Central Maine Power Emera Maine Maine Natural Gas Northern Utilities	Purchased Power Decoupling Environmental Compliance Infrastructure Capex Other	4

Table continued on next page

States	Utility	Type	Count of Utilities with Riders and Trackers
Maryland	Baltimore Gas & Electric Columbia Gas of Maryland Delmarva Power & Light Potomac Edison Potomac Electric Power Washington Gas Light	Purchased Power Conservation Program Decoupling Infrastructure Capex Other	6
Massachusetts	Bay State Gas Berkshire Gas Boston Gas/Colonial Gas Fitchburg Gas & Electric Liberty Utilities (New England Gas) Massachusetts Electric NSTAR Electric NSTAR Gas Western Mass. Electric	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	9
Michigan	Consumers Energy DTE Electric DTE Gas Indiana Michigan Power Michigan Gas Utilities SEMCO Energy Gas Upper Peninsula Power Wisconsin Electric Power	Purchased Power Conservation Program Decoupling Renewables Infrastructure Capex RTO Expense	8
Minnesota	Minnesota Power CenterPoint Energy Resources Minnesota Energy Resources Northern States Power-Minnesota Otter Tail Power	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex RTO Expense	5
Mississippi	Atmos Energy Entergy Mississippi Mississippi Power	Purchased Power Conservation Program Decoupling Environmental Compliance Generation Capacity Capex RTO Expense Other	3
Missouri	Empire District Electric Empire District Gas Kansas City Power & Light KCP&L Greater Missouri Operations Laclede Gas Liberty Utilities (Midstates Natural Gas) Missouri Gas Energy Union Electric	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex RTO Expense Other	8
Montana	MDU Resources NorthWestern Corp.	Purchased Power Conservation Program Decoupling Other	2
Nebraska	Black Hills Nebraska Gas Utility Northwestern Energy Black Hills Gas Distribution	Purchased Power Infrastructure Capex Other	3
Nevada	Nevada Power Sierra Pacific Power Southwest Gas	Purchased Power Conservation Program Decoupling Infrastructure Capex Other	3

Table continued on next page

States	Utility	Type	Count of Utilities with Riders and Trackers
New Hampshire	Liberty Util. (EnergyNorth Natural Gas) Liberty Util. (Granite State Electric) Northern Utilities Public Service Co. of New Hampshire Unitil Energy Systems	Purchased Power Infrastructure Capex RTO Expense	5
New Jersey	Atlantic City Electric Jersey Central Power & Light New Jersey Natural Gas Pivotal Utility Holdings Public Service Electric & Gas Rockland Electric South Jersey Gas	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex Other	7
New Mexico	El Paso Electric New Mexico Gas Public Service Co. of New Mexico Southwestern Public Service	Purchased Power Conservation Program Renewables Environmental Compliance Infrastructure Capex Other	4
New York	Brooklyn Union Gas Central Hudson Gas & Electric Consolidated Edison of New York KeySpan Gas East National Fuel Gas Distribution New York State Electric & Gas Niagara Mohawk Power Orange & Rockland Utilities Rochester Gas & Electric	Purchased Power Decoupling Renewables	9
North Carolina	Duke Energy Carolinas Duke Energy Progress Piedmont Natural Gas Public Service Co. of North Carolina Virginia Electric & Power	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Infrastructure Capex	5
North Dakota	MDU Resources Northern States Power-Minnesota Otter Tail Power	Purchased Power Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex Other	3
Ohio	Cleve. Elec. Illum./Ohio Ed./Toledo Ed. Columbia Gas of Ohio Dayton Power & Light Duke Energy Ohio East Ohio Gas Ohio Power Vectren Energy Delivery of Ohio	Purchased Power Conservation Program Decoupling Renewables Infrastructure Capex RTO Expense Other	7
Oklahoma	CenterPoint Energy Resources Oklahoma Gas & Electric Oklahoma Natural Gas Public Service Oklahoma	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	4
Oregon	Avista Corp. Cascade Natural Gas Idaho Power Northwest Natural Gas PacifiCorp Portland General Electric	Purchased Power Decoupling Renewables Environmental Compliance	6

Table continued on next page

States	Utility	Type	Count of Utilities with Riders and Trackers
Pennsylvania	Columbia Gas of Pennsylvania Duquesne Light Equitable Gas Metropolitan Edison National Fuel Gas Distribution PECO Energy Pennsylvania Electric Pennsylvania Power Peoples Natural Gas PPL Electric Utilities UGI Central Penn Gas UGI Penn Natural Gas UGI Utilities West Penn Power	Purchased Power Conservation Program Decoupling Infrastructure Capex RTO Expense Other	14
Rhode Island	Narragansett Electric	Purchased Power Conservation Program Decoupling Environmental Compliance Infrastructure Capex Other	1
South Carolina	Duke Energy Progress Duke Energy Carolinas Piedmont Natural Gas South Carolina Electric & Gas	Purchased Power Decoupling Environmental Compliance Generation Capacity Capex	4
South Dakota	Black Hills Power Northern States Power-Minnesota NorthWestern Corp.	Purchased Power Conservation Program Decoupling Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	3
Tennessee	Atmos Energy Chattanooga Gas Kingsport Power Piedmont Natural Gas	Purchased Power Decoupling Infrastructure Capex Other	4
Texas	AEP Texas Central AEP Texas North Atmos Energy CenterPoint Energy Houston Electric CenterPoint Energy Resources Cross Texas Transmission El Paso Electric Electric Transmission of Texas Entergy Texas Lone Star Transmission Oncor Electric Delivery Southwestern Electric Power Southwestern Public Service Texas-New Mexico Power Wing Energy Transmission of Texas Texas Gas Service	Purchased Power Conservation Program Decoupling Infrastructure Capex RTO Expense Other	16
Utah	PacifiCorp Questar	Purchased Power Conservation Program Decoupling Renewables Infrastructure Capex Other	2

Table continued on next page

States	Utility	Type	Count of Utilities with Riders and Trackers
Vermont	Green Mountain Power Vermont Gas System	Purchased Power	2
Virginia	Appalachian Power Columbia Gas of Virginia Kentucky Utilities Virginia Electric & Power Virginia Natural Gas Washington Gas	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Generation Capacity Capex Infrastructure Capex RTO Expense Other	6
Washington	Avista Corp. Cascade Natural Gas Northwest Natural Gas PacifiCorp Puget Sound Energy	Purchased Power Decoupling Infrastructure Capex	5
West Virginia	Appalachian Power/Wheeling Power Hope Gas Monongahela Power Mountaineer Gas Potomac Edison	Purchased Power Infrastructure Capex RTO Expense Other	5
Wisconsin	Madison Gas & Electric Northern States Power-Wisconsin Wisconsin Electric Power Wisconsin Gas Wisconsin Power & Light Wisconsin Public Service	Purchased Power Other	6
Wyoming	Cheyenne Light Fuel & Power MDU Resources PacifiCorp Black Hills Gas Distribution	Purchased Power Conservation Program Decoupling Renewables Environmental Compliance Other	4
		Count of Utilities with Riders and Trackers	257

Source: "Adjustment Clauses, A State-by-State Overview," Regulatory Research Associates, August 2016.

Appendix B: Case Studies – Representative Regulatory Frameworks

Appendix B includes fourteen case studies analyzing eleven utilities. We have focused our review on distribution utilities or the distribution activities of vertically-integrated utilities. For instance, when we note that no TPIs are defined for some utilities, non-distribution related TPIs may exist but were not included in the scope of our review for the purpose of this report.

Please note that the paragraph labelled "Business Segment" describes the utility's business segment at stake in the plan described in the case study. Some utilities' activities may only include that specific segment (e.g., ATCO is a distribution utility), while other utilities may have a broader range of activities than the business segment we are focusing on in the relevant case study (e.g., PG&E is a vertically-integrated utility but defines a revenue requirement specific to distribution, which is what we choose to discuss in the PG&&E case study).

Pacific Gas & Electric Company (PG&E)

Fully-integrated Electricity & Natural Gas Utility
California, USA

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Multi-year Rate Plan with Stair-step Trajectory

Characteristics of the plan:

- **Business segments:** Electricity distribution and natural gas distribution.[1]
- **Ratemaking methodology**: Multi-year Rate Plan with a stair-step attrition relief mechanism.
- **Length:** 3 years.
- **Decoupling**: Full decoupling for both electricity and gas distribution.[2]
- **Ratemaking Scope:** All electricity/natural gas distribution expenditure except for costs that are collected via balancing accounts or an exogenous rider/tracker mechanism (Z-factor).
- **Rate adjustments (between rate cases):**

  Escalation in revenues for the MRP term is decided at the outset of each rate case using a stair-step ARM. PG&E uses a combination of historical trending and forecasting to determine the revenue requirement for the first "test" year (year 1 of the 3-year term). In the Settlement Agreement and Commission Decision for the latest rate case, operating expenses for the "post-test" years (years 2 and 3) are escalated by applying an "appropriate" (i.e., particular to the cost category) escalation rate to the adopted test year amounts. Capital revenue requirement growth is modeled based on adopted test year plant additions, escalation rates, forecast depreciation, estimated change in deferred tax liabilities.[3]
- **Regulatory / Legislative Authority:**

  CPUC Decision 89-01-040 in 1989 set the rate term for all California utilities to be three years.[4]

  PG&E has had 7 rate cases with MRP since 1989. Historically, PG&E has generally used an indexing ARM for at least some of its expenditures. Beginning in 2007, PG&E has transitioned to an MRP with a stair-step ARM approach.[5]

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[1] The distribution revenue requirement is set separately from PG&E's other business segments. See California Public Utilities Commission (CPUC) Decision 14-08-032, "Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016," Appendix C – Decision Tables – Test Year 2014, August 14, 2014.

[2] SNL, "SNL RRA Topical Special Report – Adjustment Clauses," August 22, 2016, p. 3.

[3] CPUC Decision 17-05-013, "Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2017-2019," Application 15-09-001, May 11, 2017, pp. 48-51.

[4] CPUC Decision 89-01-040, "Order Instituting Rulemaking to revise the time schedules for the Rate Case Plan and fuel offset proceedings," Appendix B – Rate Case Plan, January 22, 1989, p. B-8.

[5] Lowry, Mark Newton, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," Edison Electric Institute, Table 7: Multiyear Rate Plan Precedents, November 11, 2015, p. 43.

- **Reopeners / Off-Ramps:** No specific re-opening or off-ramp provisions except that the Commission states: "PG&E shall notify the Commission of any tax-related changes, any tax-related accounting changes, or any tax-related procedural changes that materially affect, or may materially affect, revenues. Our reference to 'materially affect' means a potential increase or decrease of $3 million or more." For other unforeseen changes traditional regulatory recourse is available, although we do not know of any PG&E MRPs being reopened.[6]

- **Earnings Sharing Mechanism:** None.[7]

- **TPIs:** Currently, no TPIs are applied to PG&E.

- **Riders / Trackers:**

  PG&E has several balancing accounts to track costs for various projects or events, such as major emergencies or vegetation management.[8] For example, the Vegetation Management Balancing Account is a one-way, "use-it-or-lose-it" mechanism that allocates funding for tree trimming and removal, environmental compliance, and other related work. All under spending is credited to customers.[9] The Catastrophic Event Memorandum Account allows PG&E to record costs related to state or federal government-declared emergencies and ask for recovery of these costs in later proceedings.[10] Other riders/trackers include the Smart Grid Memorandum Account, Pipeline Safety Implementation Plan, and Smart Grid Pilot Deployment. We provide a detailed case study for the Pipeline Safety Implementation Rider/Tracker later on.

  PG&E also has a Z-factor mechanism for post-test years that captures exogenous events (i.e., events outside of the utility's control) that have a major impact on PG&E's cost of service, with a $10m deductible per event.[11]

- **Timeline of the last rate case:**
  - General Rate Case (GRC) application from PG&E: September 1, 2015
  - Settlement Agreement filed: August 3, 2016
  - Final decision issued: May 11, 2017
  - Rates to be applicable starting: January 1, 2017

6 California Public Utilities Commission (CPUC) Decision 17-05-013, "Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2017-2019," Application 15-09-001, May 11, 2017, pp. 116

7 CPUC Decision 17-05-013, pp. 118-119 and PG&E, "General Rate Case Application of Pacific Gas and Electric Company," September 1, 2015.

8 Ibid, pp. 10-11.

9 PG&E Application – Exhibit PG&E-4, "Electric Distribution," September 1, 2015, p. 7-18.

10 Lau, Elaine, "Cost Recovery Mechanisms for Energy Utilities," Presentation at CPUC Commissioner Committee Meeting, October 26, 2016, p. 4.

11 CPUC Decision 17-05-013, pp. 48.

Latest discussions on changes to framework:

During the settlement process for the 2017 GRC, PG&E and the Office of Ratepayer Advocates recommended that the rate term be extended from 3 to 4 years. The CPUC decided to delay this matter until other safety and risk assessment proceedings had concluded.[12] In January 2017, the CPUC hosted a workshop to explore options to facilitate timely processing of GRC and related proceedings, including moving to a longer GRC cycle. As of the CPUC Decision in the 2017 GRC in May 2017, the post-workshop report has not been completed.[13]

At a higher level, California is currently considered a leader in the Utility of the Future dialogue that acknowledges a new regulatory framework and/or business model is needed to address challenges facing utilities.[14] At this time, the Commission has not proposed a major overhaul but instead had decided to address challenges such as rate reform, incentives for distributed generation, and optimization of rooftop PV on the distribution grid in individual dockets while it contemplates future approaches.[15] A recent CPUC whitepaper calling for greater coordination across these dockets pointed to three new potential business models, all of which would involve performance based incentives for achieving certain operating targets, customer service goals, or implementing various regulatory policy goals.[16]

Important sources/references:

- CPUC decision on PG&E's most recent rate case: CPUC Decision 17-05-013, "Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2017-2019," Application 15-09-001, May 11, 2017.
- PG&E's 2017 General Rate Case Application: PG&E, "General Rate Case Application of Pacific Gas and Electric Company," September 1, 2015.

[12] CPUC Decision 17-05-013, pp. 197-198.
[13] Ibid. More information on this workshop is available at: http://www.cpuc.ca.gov/General.aspx?id=6442452096.
[14] "Staff Report on Grid Modernization," Minnesota Public Utilities Commission, March 2016, p. 31.
[15] See Dockets on Residential Rate Reform (R.12-06-013), Distributed Generation (R.12-11-005), Integrated DSM (R.14-10-003), and Distribution Resource Plans (R.14-08-013).
[16] Ralff-Douglas, Kristin and Marzia Zafar, "Electric Utility Business and Regulatory Models," California Public Utility Commission, June 8, 2015.

Northern States Power d/b/a Xcel Energy

Fully-integrated Electric Utility
Minnesota, USA

THE Brattle GROUP

Multi-year Rate Plan with Stair-step Trajectory

Ratemaking Characteristics:

- **Business segments:** Fully-integrated electric revenue requirement.
- **Ratemaking methodology**: Multi-year Rate Plan with a stair-step attrition relief mechanism.
- **Length:** 4 years.
- **Decoupling:**

  Decoupling on a pilot basis.

  Xcel Energy, operating as Northern States Power Company in Minnesota, currently has a four-year pilot full Revenue Decoupling Mechanism with a cap on revenue adjustments of 3% of all revenues from residential customers and small commercial and industrial customers who do not pay a demand charge.[1] These customer classes, which represent 95% of Xcel Energy's customer base and 30% of their annual electricity sales, are those for which the largest share of fixed costs are recovered through volumetric rates. Xcel Energy may petition to recover costs above the 3% cap in the following year provided that it can demonstrate that the relevant initiatives were a substantial contributing factor to the declining energy consumption that led to the under-recovery, rather than other, non-conservation factors. The pilot program began in 2016 and was extended to the end of the current rate plan in 2019.[2]

  Xcel Energy used weather normalized actual sales to set final 2016 rates, and also conducts a weather-normalized adjustment to account for actual sales for non-decoupled classes from 2017-2019.[3]

- **Ratemaking Scope:** All electricity expenditure except for fuel and pass-through costs that are collected by a Fuel Clause Adjustment mechanism and riders/Trackers, respectively (see the "Riders/ Trackers" section).
- **Rate adjustments (between rate cases)**:

  The revenue escalation is set within the rate case for the next four years. The revenue requirement is based on a 2016 test year, which was initially forecasted but will be adjusted for weather-normalized actual 2016 sales.[4]

  The 2016 rate case for the electric utility was the first multi-year rate plan filed with the MPUC. Xcel Energy offered both a three- and five-year MRP option in its application, with the five-year option including a simple

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[1] The program was initially a three-year pilot, but a settlement approved in May 2017 extended the pilot to four years. Northern States Power Company, "Xcel Energy Electric Rate Case 2016 Decoupling Annual Report," Dockets Nos. E002/GR-13-868 and E002/GR15-826, February 1, 2017, pp. 5-9; Press Release – "Minnesota Public Utilities Commission Acts on Xcel Energy's Multi-year Electric Rate Case," May 12, 2017, p. 1.

[2] Ibid.

[3] Northern States Power Company, "Stipulation of Settlement Authority to Increase Electric Rates," Docket No. E002/GR-15-826, August 16, 2016, p. 6.

[4] Ibid, p. 4, 6.

growth rate of 1.8% after setting going-in rates for 2016 using a cost-of-service methodology.[5] The parties agreed on a settlement that set rates for four years.[6]

- **Regulatory / Legislative Authority:**

  Modification from traditional regulatory framework requires legislative authority.

  In 2009, Minnesota Law (Chapter 110 -S.F. No. 550) required the Minnesota Public Utilities Commission (MPUC) to prepare a Utility Rates Study that examined automatic cost recovery mechanisms and alternative forms of utility rate regulation. This mandate led to the development of a report by the MPUC as well as other materials by the National Regulatory Research Institute (NRRI) on alternative performance based regulation topics to help guide discussion.[7]

  In 2011, Senate Bill 1197 in Minnesota authorized the Commission to approve MRPs for gas and electric utilities with a term up to three years. In 2015, the Minnesota legislature modified the multi-year rate plan statute to allow for the extension of rate plan terms to up to five years, as well as to allow the Commission to require utilities to provide performance measures and incentives as part of their rate case applications.[8]

  Xcel was the first Minnesota utility to file a rate case requesting an MRP, and is a member of the e21 Initiative advocating MRPs and more performance-based regulation.[9]

- **Reopeners/Off-Ramps:** No specific provision for reopening and/or off-ramps, other than through standard regulatory recourse.

- **Earnings Sharing Mechanism:** None. As part of its last rate case, Xcel had requested that a symmetrical earnings sharing provision be included in the five-year MRP proposal. That is, the utility would share with ratepayers 50% of returns above the deadband, and rates would be increased to share 50% of the shortfall below the deadband with ratepayers.[10] However, the proposed ESM was not a part of the settlement adopted by the MPUC.[11]

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5 Northern States Power Company, "In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota," Docket No. E002/GR-15-826, November 2, 2015, p. 2; and "Direct Testimony and Schedules Aakash H. Chandarana," Docket No. E002/GR-15-826, November 2, 2015, pp. 70-71..

6 Press Release – "Minnesota Public Utilities Commission Acts on Xcel Energy's Multi-year Electric Rate Case," May 12, 2017, p. 1.

7 "Report To The Legislature: Utility Rates Study As Required By Laws Of Minnesota, 2009, Chapter 110," Submitted by the Minnesota Public Utilities Commission, June 2010.

8 Minnesota statute § 216B.16, subd. 19, available at: https://www.revisor.mn.gov/statutes/?id=216b.16.

9 Jeffrey Tomich, "Initiative aims to reinvent utility industry the Minnesota way," E&E News, November 25, 2015.

10 "Direct Testimony and Schedules Aakash H. Chandarana," Docket No. E002/GR-15-826, November 2, 2015, pp. 76-77.

11 Minnesota Public Utilities Commission, "In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota: Findings of Fact, Conclusions, and Order," Docket No. E002/GR-15-826, June 12, 2017, pp. 33-34.

- **TPIs:** Xcel Energy has TPIs covering reliability and customer complaints.[12] The TPI plan is structured as asymmetrical downward, (i.e., penalty for performance below targeted levels only, and no rewards for performance above targeted levels).[13] In the last rate case, Xcel proposed new emerging performance metrics that would not be tied to any penalty or incentive but they were not accepted in the Settlement. A separate docket with the MPUC has been created to identify and develop new performance based metrics and incentives.[14]
- **Riders / Trackers:**

  Xcel Energy uses 26 different riders/trackers to recover various pass-through costs, related to energy efficiency, services for specific customer classes, and environmental improvement, among other areas.[15]
- **Timeline of the last rate case:**
  - Application from Xcel Energy to increase its electric rates: November 2, 2015
  - Settlement submitted by majority of parties: August 16, 2016[16]
  - Final decision issued: May 11, 2017[17]
  - Rates to be applicable starting: An interim rate increase of $163.7 million was effective January 1, 2016 and subject to refund. Customers will receive a refund for the difference from final rates.

Latest discussions on changes to framework:

In 2014, the Great Plains Institute and the Center for Energy and Environment launched the e21 Initiative, which also had a docket with the Minnesota Public Utilities Commission.[18] Xcel Energy is also a participant in the e21 Initiative. This initiative offers several recommendations to shift Minnesota's electric utilities to a more customer-centric and sustainable business model. One focus of this initiative is performance based ratemaking. The Phase I

[12] Minnesota Public Utilities Commission, "In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota: Findings of Fact, Conclusions, and Order," Docket No. E002/GR-15-826, June 12, 2017, pp. 22-23.

[13] In 2002, Xcel was accused by an internal whistleblower of tampering with reliability data in order to increase performance on its metrics. The matter was eventually settled in an agreement with the company. See "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," O'Neil Management Consulting LLC , December 13, 2012, pp. 50-51.

[14] Minnesota Public Utilities Commission, "In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota: Findings of Fact, Conclusions, and Order," Docket No. E002/GR-15-826, June 12, 2017, pp. 22-23.

[15] Northern States Power Company, "Stipulation of Settlement Authority to Increase Electric Rates," Docket No. E002/GR-15-826, August 16, 2016, Attachment 3. Some examples of these riders/trackers include the Conservation Improvement Program Adjustment Rider/Tracker, Low Income Energy Discount Rider/Tracker, Residential Controlled Air Conditioning and Water Heating Rider/Tracker, and Mercury Cost Recovery Rider/Tracker.

[16] Xcel Energy, "Stipulation of Settlement Authority to Increase Electric Rates," August 16, 2016.

[17] Press Release – "Minnesota Public Utilities Commission Acts on Xcel Energy's Multi-year Electric Rate Case," May 12, 2017, p. 1. A formal writer order will be issued by June 12, 2017.

[18] See the e21 website here: http://www.betterenergy.org/projects/e21-initiative, as well as Minnesota Public Utilities Commission Docket No. 14-1055.

and Phase II Reports recommended that the state move to longer-term (up to five-year) multi-year rate plans with TPIs.[19] Some potential performance targets suggested in the Phase II Report include better integration of distributed energy resources, better efficiency and cost control, emissions reductions, access to a wider range of utility services and products, energy conservation, greater system reliability, and greater customer satisfaction and affordability.[20]

Important Sources/references:

- Northern States Power Company, "Application for Authority to Increase Rates for Electric Service in the State of Minnesota," Docket No. E002/GR-15-826, November 2, 2015.
  - NSP's first three-year MRP application.
- "Phase II Report: On implementing a framework for a 21st century electric system in Minnesota," e21 Initiative, December 2016.
  - Report on implementing changes to the utility business model, including using MRP plans.
- Northern States Power Company, "Xcel Energy Electric Rate Case 2016 Decoupling Annual Report," Docket Nos. E002/GR-13-868 and E002/GR15-826, February 1, 2017.
  - NSP's annual revenue decoupling pilot report.

[19] "Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota," e21 Initiative, December 2014, p. 8, and "Phase II Report: On implementing a framework for a 21st century electric system in Minnesota," e21 Initiative, December 2016.

[20] "Phase II Report: On implementing a framework for a 21st century electric system in Minnesota," e21 Initiative,December 2016, pp. 40-45.

Consolidated Edison (Con Edison)

Electricity and Natural Gas Distribution Utility
New York, USA

THE Brattle GROUP

Multi-year Rate Plan with Stair-step Trajectory, TPIs and Capex Riders/Trackers

Ratemaking Characteristics

- **Business segments:** Electricity distribution and natural gas distribution.[1]
- **Ratemaking methodology:** Multi-year Rate Plan with a stair-step Attrition Relief Mechanism.
- **Length:** 3 years.
- **Decoupling:** Electricity and gas are fully decoupled under their Revenue Decoupling Mechanism.[2]
- **Ratemaking Scope:** All electricity/natural gas distribution expenditures, except for a few specific project capital expenditures.
- **Rate adjustments (between rate cases):**

  The revenue escalation is set within the rate case for the next three years. It is set based on evidence put together by Con Edison regarding their forecast of sales, property taxes, depreciation expenses, plant in service, operations and maintenance expense, leak inspection and repairs expense, infrastructure investment, and other miscellaneous expenses (i.e., pension expenses).[3]
- **Regulatory / Legislative Authority:**

  No specific legislation required. The MRPs as well as other mechanisms (TPIs and capex riders/trackers) were developed under NYPSC initiatives. For example, Earning Adjustment Mechanisms (see the TPIs section) were established in response to the Reforming the Energy Vision Track Two Order implemented in May 2016.[4]
- **Reopeners / Off-Ramps:**

  Con Edison's MRP includes a standard provision for "Continuation of Provisions; Rate Changes; Reservation of Authority" that allows Con Edison to file for a rate increase at any time if circumstances threaten its economic viability or ability to provide service. It also includes additional detailed provisions allowing Con Edison to defer increased expenses related to unforeseen changes through law (including tax law) rule, regulation, or order.[5]

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[1] SNL, "Rate Case History," accessed 6/2/2017.
[2] State of New York Public Service Commission (NYPSC), "Order Approving Electric and Gas Rate Plans," Dockets 16-E-0060, 16-G-0061, and 16-E-0196, January 25, 2017, p. 21.
[3] NYPSC (2017), pp. 3-5.
[4] See NYPSC, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," Case 14-M-0101, May 19, 2016, pp. 53-93.
[5] NYPSC, "Order Approving Electric and Gas Rate Plans," Docket 13-E-0030 et al., February 21, 2014, pp. 115-117.

- **Earnings Sharing Mechanism**:

  Con Edison has an Earnings Sharing Mechanism (ESM). For both electric and gas, if the earned ROE exceeds a threshold of 50 basis points above the approved ROE, the earnings will be divided between ratepayers and the company. The ratio of the amount given to ratepayers and the company is dependent on how much above the threshold is earned:

  – If earned ROE is between 50 and 100 basis points above approved: 50% goes to ratepayers and 50% goes to Con Edison

  – If earned ROE is between 100 and 150 basis points above approved: 75% goes to ratepayers and 25% goes to Con Edison

  – If earned ROE is above 150 basis points: 90% goes to ratepayers and 10% goes to Con Edison

  However, half of the earnings received by Con Edison and all of the customer earnings will go toward Site Investigation and Remediation costs or other interest bearing cost deferrals.[6] This approach is different than typical ESM's where funds returned to customers are generally done through price adjustments, refunds, or through increased investment.[7]

- **TPIs:**

  – *Traditional:* Con Edison has a Reliability Performance Mechanism, which is based on seven performance metrics (with sub-metrics in each category), including system-wide performance targets, a major outage metric, and program standards for infrastructure maintenance. The annual revenue adjustment exposure varies for each target within each metric. Con Edison files an annual report on its performance each year and any revenue adjustment is deferred and removed from shareholder funds.[8]

    Con Edison has a Customer Service Performance Mechanism that includes, but is not limited to, targets for customer satisfaction (measured using surveys) and commission complaints.[9] They also have Electric Safety Standards with related negative revenue adjustments.[10]

    Con Edison also has a gas performance mechanism with annual targets for leak prone pipe replacement, emergency response time, and damage prevention and counts, with basis point reductions to the ROE if Con Edison does not meet the targets. The leak prone and main pipe replacement also has a positive

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6 NYPSC (2017), p. 27.

7 Public Utility Research Center Warrington College of Business, "Body of Knowledge on Infrastructure Regulation – Earnings Sharing," accessed June 15, 2017, available at: http://regulationbodyofknowledge.org/price-level-regulation/.

8 These sub-metrics include repair of current street lights and traffic signals, remote monitoring system, removal of temporary shunts, replacement of over-duty circuit breakers, damaged pole repairs, major outage metric, CAIDI, SIAFI, and outage notifications. See Appendix A-3 and A-4 for definitions. NYPSC, "Joint Proposal", Docket 16-E-0060 et al., September 19, 2016, Appendix 14.

9 See Appendix A-3 and A-4 for definitions. Ibid, Appendix 17.

10 Ibid, Appendix 15.

incentive if Con Edison exceeds the target. Replacement costs for other projects above this target are recovered in another mechanism.[11]

- *Emerging:* Con Edison has two program achievement Earning Adjustment Mechanisms (EAMs) for meeting or exceeding target levels regarding incremental GWh savings and system peak reduction. They also have three EAMs which are outcome-based:[12]
  - Energy Intensity – encourages Con Edison to help customers reduce energy intensity.
  - Distributed Energy Resource Utilization – motivates Con Edison to increase distributed energy resource utilization.
  - Customer Load Factor – incentivizes Con Edison to improve the load factor for poor load factor customers.

- **Riders / Trackers:**
  - In Con Edison's most recent rate case, it discusses the following riders/trackers:
    - Non-Wire Alternatives (NWA) mechanism that allows Con Edison to recover the difference between a NWA initiative (like DER interconnection) and capital expenditures on infrastructure projects.[13,14]
    - Con Edison will recover costs for a "Climate Change Vulnerability Study" and a marginal cost study.[15]
  - In addition to the NWA mechanism, NWA projects qualify for incentives that are approved by the Commission for the existing Con Edison Targeted Demand management program.[16]
  - Con Edison has other riders/trackers that allow them to recover some specific O&M spending such as customer bill credits.[17]
- **Timeline of last rate case:**
  - Separate applications from Con Edison electric and gas distribution: January 29, 2016
  - Final decision issued together for gas and electric: January 24, 2017
  - Rates to be applicable starting: January 1, 2017

Latest discussions on changes to framework:

Most of Con Edison's joint proposals have included MRPs since 1989, varying between 2 to 3 years in length.[18] Most of those MRPs included a stair-step ARM, although a few have been rate freezes (i.e., 2013) or single-year plans (i.e.,

[11] NYPSC (2017), p. 25 and NYPSC (Sept 2016), Appendix 16.
[12] Several of these EAMs are still being developed. NYPSC (2017), pp. 71-73, 83, 98-99.
[13] Ibid., p. 30.
[14] The Brooklyn Queens Demand Management program is a notable NWA program. NYPSC (May 2016), p. 6.
[15] NYPSC (2017), p. 20.
[16] Ibid, p. 30.
[17] Ibid, pp. 20-21.
[18] The last rate plan set a two-year plan for electric delivery and a three-year plan for gas delivery.

electric's 2007 case). Gas distribution has had an average of one rate case every three years since 2005 and electric distribution has had one about every two years.[19] While the Commission has been approving Joint Proposals that contain MRPs, no formal amendment to the public service law regarding the powers of the NYPSC has been passed to explicitly state that the Commission may set multi-year rates.[20] A bill in 2010 was proposed to make such an amendment but never made it past committee approval.[21] However, an amendment has been proposed in the last five legislative sessions to require annual evaluation of rates that were passed under MRPs.[22]

The NYPSC created the "Reforming the Energy Vision" (REV) proceeding in April 2014 for the purpose of changing the electric utility model in preparation for distributed generation and new technologies. "Track Two" of this proceeding was launched in May 2016, which considers changes in rate design and performance-based regulation, including the 'RIIO' regulatory model.[23] REV pushed utilities to move away from cost-of-service ratemaking because it does not address several of the changes in the energy system. The NYPSC noted that, until now, regulated distribution utilities have been shielded from the opportunities and competition of today's market, which keeps productivity and efficiency low.[24]

In the order establishing Track Two REV, the NYPSC considered RIIO (totex in particular) ratemaking but decided there were several obstacles in adopting a totex approach. The NYPSC was concerned that totex would continue to incentivize a utility to maximize its expenditures, noting that the EAMs and other market-based earning mechanisms were intended to have the opposite effect. However, the NYPSC continues to investigate RIIO approaches and the UK experiences.[25]

Important sources/references:

- State of New York Public Service Commission, "Order Approving Electric and Gas Rate Plans," Dockets 16-E-0060, 16-G-0061, 16-E-0196, January 25, 2017.
  - Con Edison's most recent rate case establishing a multi-year rate plan as they have before.
- State of New York Public Service Commission, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," Docket 14-M-0101, May 19, 2016.
  - Decision establishing Track Two of the Reforming the Energy Vision proceeding.

[19] SNL, "Rate Case History," accessed 6/2/2017.
[20] New York, Public Service Law, § 66.
[21] New York State Senate Bill S7278, "An Act to Amend the Public Service Law, in Relation to Prices, Rates and Charges," 2010.
[22] New York State Senate Bill S3303, "An Act to Amend the Public Service Law, in Relation to Requiring Annual Reviews of Multi-Year Rate Plans," 2017.
[23] Con Edison, "Policy Management and Regulatory Impact," available at: https://www.conedison.com/ehs/2014-sustainability-report/managing-our-business/policy-management-and-regulatory-impact/.
[24] NYPSC (May 2016), p. 4.
[25] Ibid, pp. 103-104.

Florida Power and Light (FPL)

Fully Integrated Electric Utility
Florida, USA

THE Brattle GROUP

Multi-year Rate Plan with Stair-step Trajectory

Ratemaking Characteristics:

- **Business segments:** Fully-integrated electric revenue requirement that covers generation upgrades, transmission, and distribution.
- **Ratemaking methodology:** Multi-year Rate Plan with a stair step Attrition Relief Mechanism.
- **Length:** 4 years.
- **Decoupling:** None.[1]
- **Ratemaking Scope:** All electricity expenditure except for fuel, new generation build, some capital expenditures, and pass-through costs that are collected by a Fuel Adjustment Clause, Capacity Cost Recovery Clause, and riders/trackers, respectively.
- **Rate adjustments (between rate cases):**

  The revenue escalation for each year is set within the rate case for the next four years. In the last rate case, FPL's application estimates the revenue escalation with forecast spending and capital investments. The first two years of the plan (2017 and 2018) includes a "comprehensive" forecast of expenditures and capital investments, while the revenue requirement for years three and four (2019 and 2020) only account for the addition of a generation unit.[2] FPL characterizes this forecasting approach as being in line with Florida Public Service Commission (FPSC) practices and approved by the Supreme Court of Florida.[3] In its March 2016 application, FPL reminds that the Court "long ago recognized that rates are fixed for the future and that it is appropriate for [the Commission] to recognize factors which affect future rates and to grant prospective rate increases based on these factors."[4]

- **Regulatory / Legislative Authority:**

  Legislative authority appears to be required for any changes to traditional cost of service ratemaking. FPL submits its MRP under the authority of Statute 366 and Florida Administrative Code, and Rules 25-6.0425, 25-6.043, and 25-6.0431. To implement further PBR legislative change is needed. See the "Latest discussions on changes to framework" section for a recently proposed change.

[1] "Adjustment Clauses- A State-by-State Overview," SNL Regulatory Research Associates, August 22, 2016.
[2] Florida Power and Light Company Petition for Rate Increase, FPSC Docket No. 160021-EI, March 15, 2016, p. 9 ¶ 17.
[3] Ibid., p. 10 ¶ 21.
[4] Ibid., p. 11.

- **Reopeners / Off-Ramps:**

  FPL is described as having an off-ramp for at 100 basis points below the authorized ROE.[5] If FPL's earned ROE falls below 9.5%, the company would be permitted to seek a rate increase, and if the earned ROE were to exceed 11.5%, any party to the settlement, other than FPL, is permitted to seek a rate review.[6]

- **Earnings Sharing Mechanism:** FPL does not have any earning sharing mechanisms.[7]

- **TPIs:**

  None regarding the distribution business. FPL has an incentive mechanism for wholesale power sales that allows the utility to share the cost savings it achieves through wholesale electric purchases and sales as well as asset optimization. This includes cost savings from gas storage utilization, city-gate gas sales using existing transport, reduction area gas sales, capacity release of gas transport and electric transmission, and outsourcing of the optimization function. There is an initial threshold of $40 million in savings that must be reached before FPL can earn a reward.[8]

- **Riders / Trackers:**

  There are no capex riders/trackers. However, riders/trackers are used to recover expenditures made by FPL in response to special circumstances:

  – Storm Damage Cost Recovery Mechanism: This mechanism allows FPL to recover damages from major storms at $4 per 1,000 kWh over 12 months after a cost recovery petition is filed.[9] Recovery of any additional costs is deferred until the next rate case.

  – Temporary Hurricane Recovery Surcharge: This temporary mechanism recovers direct costs from recent storms, such as Hurricane Matthew in 2016, over 12 months.

  The recovery approach is also used for recovery of energy conservation related expenditures:

  – Energy Conservation Cost Recovery Charge and Environmental Cost Recovery Clause.[10]

- **Timeline of the last rate case:**

  – Application from FPL: March 15, 2016

  – Final decision issued: December 17, 2016

  – Rates to be applicable starting: January 1, 2017

[5] "Earnings Sharing Mechanism Prepared Direct Testimony of Robert C. Yardley, Jr. On behalf of Gaz Métro Limited Partnership," Presented to the Régie de l'énergie, February 9, 2015, p. 11.
[6] "Financial Focus: Next Era Energy," Regulatory Research Associates, November 9, 2016, p. 3.
[7] Mark Newton Lowry et al., "Alternative Regulation for Emerging Utility Challenges: 2015 Update," Pacific Economics Group for the Edison Electric Institute, November 11, 2015." See Table 7.
[8] Approved in Order PSC-13-0023-S-EI.
[9] FPSC Order PSC-16-0560-AS-EI, p. 3.
[10] "Understanding your bill: residential customers," Florida Power and Light, accessed 6/22/17. Available: https://www.fpl.com/rates/pdf/residential-explanation.pdf.

Latest discussions on changes to framework:

Florida does not have any ongoing dialogues for a large scale overhaul of utility regulation, such as a Utility of the Future effort. However, recently proposed legislation (House Bill 7101) has considered the implementation of target performance metrics. The Bill proposed establishing a TPI-like program, using performance criteria for system reliability, customer service, power plan performance and other traditional TPI areas, and also considered incorporating rewards and penalties into the plan. The bill was withdrawn from consideration in May 2017.[11]

Important sources/references:

- Florida PSC Order 16-0560-AS-EI, "Order Approving Settlement Agreement," Docket No. 160021-EI, December 15, 2016.
  - FPSC's decision on FPL's most recent rate case.
- Florida Power and Light Company Petition for Rate Increase, Docket No. 160021-EI, March 15, 2016.
  - FPL's most recent application for a rate increase. Describes FPSC ratemaking history, including FPL. Covers the history of stipulated agreements and the shift to multi-year rate plans.

[11] Utility Regulation of 2017, Proposed Florida House Bill 7071, 2017.

Public Service Electric & Gas (PSE&G)

Electricity & Natural Gas Distribution Utility
New Jersey, USA

THE Brattle GROUP

Traditional Ratemaking and Capex Rider/Tracker

Ratemaking Characteristics:

- **Business segments:** Electricity distribution and natural gas distribution.
- **Ratemaking methodology:** Traditional cost-of-service regulation for electric and gas rates.[1]
- **Length:** N/A, no MRP. In practice, length between rate cases has been 7 years (last rate case approved in the 2010).[2]
- **Decoupling:**

  Electric: None.

  Gas: Partial decoupling with a weather normalization mechanism in place. This allows PSE&G to true up gas rates based on any excess or deficiency in margin revenues compared to normal weather.[3] The Weather Normalization Clause is contingent upon PSE&G achieving capacity-reduction targets and earnings tests as agreed upon under their conservation incentive programs.[4]
- **Ratemaking Scope:** All electricity/natural gas distribution expenditure except for costs covered separately in capex riders/trackers.
- **Rate adjustments (between rate cases):**

  None, although there are true-up mechanisms in place – mainly the capex riders/trackers that are discussed below.

  Gas: The Marginal Adjustment Clause compensates/penalizes non-firm gas customers for revenues surplus / deficits associated with transportation distribution costs.[5]
- **Regulatory / Legislative Authority:**

  Neither of PSE&G's capex riders/trackers required specific legislative approval.

  The CIIP (defined below) was developed in response to the Governor's Economic Stimulus Plan in 2008, which directed the New Jersey Board of Public Utilities to implement policy that would support long-term economic growth.[6]

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[1] See State of New Jersey Board of Public Utilities (NJ BPU), "Decision and Order Approving Stipulation and Adopting Initial Decision for Electric Division," Docket GR09050422, June 7, 2010, p. 9.

[2] Gas distribution has had three rate cases since 2000 and electric distribution has only had two. See SNL, "Rate Case History," accessed 6/1/2017.

[3] NJ BPU (June 2010), Attachment C.

[4] SNL, "RRA Topical Special Report: Adjustment Clauses," August 22, 2016, p. 25, accessed 6/2/17.

[5] NJ BPU, "Decision and Order Approving Stipulation for Provisional MAC Rates," September 21, 2011, Docket GR11060338, p. 1.

The Energy Strong Adjustment Mechanism was created through PSE&G's Energy Strong Program. PSE&G proposed the Energy Strong Program in response to the New Jersey Board of Public Utilities Storm Mitigation Proceeding. This proceeding initiated an investigation to find methods to protect utility infrastructure during major storms in reaction to the devastation caused by Hurricane Sandy (2012).[7] Hurricane Sandy left 1.7 million PSE&G customers without power and inflicted major damage to infrastructure. Note that major storm events are typically handled outside of rate cases for quicker reaction.

- **Reopeners / Off-Ramps**: N/A, no MRP.
- **Earnings Sharing Mechanism**: N/A, no MRP.
- **TPIs:**

  There is no TPI plan in place.[8] PSE&G is required to report quarterly on eight customer service standards: Average Speed of Answer, Abandoned Call Percentage, Speed of Customer Representative in Seconds, Percentage of Meters Read on Cycle, Customer Rebills, Gas leak/Odor Response Time, Service Appointments Met within Benchmark, and BPU Complaints. There are no associated penalties or rewards.[9]

- **Riders / Trackers:**

  PSE&G has had a Capital Infrastructure Stimulus Program rider/tracker as well as the Energy Strong Adjustment Mechanism (ESAM). Both are covered in greater detail in the focused case studies on riders/trackers.

- **Timeline of the last rate case:**
  - Separate applications from PSE&G electric and gas distribution: May 29, 2009
  - Final decision issued: June 7, 2010 (electric) and June 18, 2010 (gas)[10]
  - Rates to be applicable starting: July 9, 2010

Latest discussions on changes to framework:

PSE&G has proposed additional approaches or mechanisms to recover costs more efficiently.

PSE&G has indicated but not formally proposed to the BPU that they will be able to modernize their grid faster and more efficiently under an expedited approval process. This could include a capital program rider/tracker, which would allow for project approval five years in advance. Currently PSE&G has received approval three years in advance. PSE&G argues that

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6 NJ BPU, "Decision and Order," Docket Nos. EO09010049, GO09010050, ER09110936, December 17, 2009, p. 2.

7 NJ BPU, "In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy Strong Program," Docket Nos EO13020155 GO13020156, May 21, 2014, p. 2.

8 There are incentive measures tied to the Weather Normalization Clause (see the "Decoupling" section) and the Energy Strong Adjustment Mechanism (see the "Riders/Trackers" section), but these are not stand-alone mechanisms.

9 NJ BPU (June 2010), p. 5 and Appendix B.

10 See SNL, "Rate Case History," accessed June 2, 2017.

a longer-term approval would allow utilities to better plan their project execution and reduce rate spikes. PSE&G also argues that five years is still a short enough time-horizon that PSE&G would have an appropriate level of oversight.[11]

PSE&G has also proposed other riders/trackers in the past. Notably, it proposed a Pension Expense Rider/Tracker in its 2010 rate case. Under this rider/tracker, ratepayers would pay for the all of the company's pension expense including the costs of any market losses. The Department of the Public Advocate Division of Rate Counsel spoke out strongly against the Pension Rider/Tracker because it would be unsupported and "inappropriate single-issue ratemaking" and would encourage inefficient management of the fund. PSE&G subsequently withdrew the Pension Expense Rider/Tracker from its rate case.[12]

PSE&G has also represented that it could achieve more EE if their rates were decoupled and had more cost pass-through. The new EE program costs that PSE&G would like to recover in its distribution rates include costs for a smart thermostat offering, a behavioral demand management program, and other "utility level" upgrades (i.e., grid upgrades). There has been pushback, especially with respect to the utility level upgrades being included in distribution rates. The Division of Rate Counsel argues that the benefits from grid upgrades would only apply to the transmission level and therefore should not be in distribution rates.[13]

Important sources/references:

- State of New Jersey Board of Public Utilities, "Decision and Order Approving Stipulation and Adopting Initial Decision for Electric Division," Docket GR09050422, June 7, 2010.
  - Most recent rate case decision for PSE&G.
- State of New Jersey Board of Public Utilities, "In The Matter of the Petition of Public Service Electric and Gas Company for Approval of Electric and Gas Base Rate Adjustments Pursuant to the Energy Strong Program," March 21, 2014.
  - Decision implementing the Energy Strong Adjustment Mechanism for PSE&G.

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[11] Utility Dive (2017).

[12] PSE&G does recover some of its pension costs under its current plan but not in the form of a rider/tracker. NJ BPU, "Department of the Public Advocate Division of Rate Counsel Initial Brief," Docket GR09050422, March 19, 2010, pp. 51-54, 106.

[13] Utility Dive (2017).

Commonweatlh Edison (ComEd)

Electricity Distribution Utility
Illinois, USA

THE Brattle GROUP

Formula Rates

Ratemaking Characteristics:

- **Business segments:** Electricity distribution.[1]
- **Ratemaking methodology:** Formula rates.
- **Length:** ComEd's formula rates were approved in 2011 and will remain in effect until 2022.[2] Rates are adjusted each year.
- **Decoupling:** None.[3]
- **Ratemaking Scope:** All electricity distribution expenditure.
- **Rate adjustments (between rate cases):**

  Rates are adjusted three ways: through the formula rate, the ROE collar, and the penalty adjustment.

  Rates are adjusted annually based on the formula rate methodology. Revenue requirements for the upcoming year are based on projected costs. For 2017, projected costs were based on actual 2015 operating costs, actual 2015 rate base, projected 2016 plant additions, and adjustments to accumulated depreciation, depreciation expense, and accumulated deferred income taxes.[4] The projected plant additions must be in compliance with infrastructure investment requirements set by the Commission and are trued up to actual cost in reconciliation filings.[5]

  Rates are also adjusted for the ROE Collar Adjustment established by the Energy Infrastructure Modernization Act (EIMA). The ROE Collar is set to 50 basis points above and below allowed ROE. If actual earnings fall outside of this range, the difference will be calculated and incorporated into the revenue requirement which is the basis for the next delivery service rates.[6]

  Finally rates are adjusted for the ROE Penalty Calculation of up 38 basis points when ComEd does not meet certain metric targets (e.g., employee safety standards), respectively. For example, ComEd did not meet its 2015 performance targets and was penalized for the 2017 revenue requirement in the most recent rate case.[7]

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1 SNL, "Rate Case History," accessed 6/2/2017.
2 Formula rates were scheduled to be in effect until 2019, until the Future Energy Jobs Act extended the formula rate plan through 2022. Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December 7, 2016.
3 SNL, "SNL RRA Topical Special Report – Adjustment Clauses," August 22, 2016, p. 18.
4 Illinois Commerce Commission (ICC) Order, "Annual Formula Rate Update and Revenue Requirement Reconciliation under Section 16-108.5 of the Public Utilities Act," Docket 16-0259, December 6, 2016, p. 3.
5 Ibid., p. 46.
Sec. 16108.5. Infrastructure investment and modernization; regulatory reform." Illinois Compiled Statues. Available at: http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K16108.5
7 Docket 16-0259, pp. 3, 41.

- **Regulatory / Legislative Authority:**

  Required by legislation. The Formula Rates process was established in Illinois under the Energy Infrastructure Modernization Act (EIMA) in 2011, which includes several amendments and additions to the Public Utilities Act.[8] EIMA was created to provide more funding for ComEd to strengthen and clean up the electric grid. The Formula Rates ruling was extended through 2022 through the Future Energy Jobs Act in 2016.[9]

- **Reopeners / Off-Ramps:** N/A, no MRP.

- **Earnings Sharing Mechanism:**

  None. However, true-ups effectively result in ongoing sharing. The true-up mechanism reconciles actual revenues with the approved revenue requirement once the data for the previous year is available. [10]

- **TPIs**:

  ComEd does not have a specific TPI plan. However, performance requirements were put in place in conjunction with formula rates (i.e. the ROE Penalty Calculation). These include: frequency of customer interruptions; duration of customer interruptions; overall improvement in exceeding service reliability targets; reduction in the number of estimated bills; opportunities for minority-owned and female-owned businesses to participate as ComEd contractors; and other performance improvement measures. If the utility does not achieve the incremental annual performance goals, it faces penalties on its return on equity of up to thirty-eight basis points. Tariffs established this as part of the annual formula rate process.[11]

- **Riders / Trackers:**

  ComEd's formula rates may be considered a form of rider/tracker. Other more specific riders/trackers are also in place; e.g., concerning energy efficiency and demand response programs.

- **Timeline of the last rate case:**
  - Initial rate case from ComEd: April 13, 2016
  - Final decision issued: December 6, 2017
  - Rates applicable starting: January 1, 2017
  - Amendment to final decision filed: December 15, 2017[12]
  - Final decision on amendment issued: March 22, 2017
  - Amended Revenue Requirement to be applicable starting: April 1, 2017[13]

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8 Illinois Senate Bill 1652, "Energy Infrastructure Modernization Act," passed October 31, 2011.
9 Illinois Senate Bill 2814 (2016).
10 Ross Hemphill and Val Jensen, "Illinois Approach to Regulation Distribution Utility of the Future," Public Utilities Fortnightly, June 2016.
11 Ibid.
12 ICC Amended Order, "Annual Formula Rate Update and Revenue Requirement Reconciliation under Section 16-108.5 of the Public Utilities Act," Docket 16-0259, March 22, 2017, p. 2.
13 Ibid., p. 7.

Latest discussions on changes to framework:

Taking effect in June 2017, the Illinois Future Energy Jobs Act includes funding for energy efficiency, net metering, and a zero emission credit program. This bill caps ComEd's spending on energy efficiency at $400 million a year but the funding is still an increase from the current level of $250 million.[14] This bill also approved energy efficiency cost recovery which is implemented with different targets for each utility.[15] For ComEd, this means they must reduce their demand by 21.5% by 2030.[16] While ComEd did not include details in their formula rate petition filed this April, they are rolling out this energy efficiency program this year.[17] If they meet their performance targets then the depreciated value of the EE assets will roll into the rate base. Initially ComEd wanted to build six microgrids as part of this program but that proposal lost support during negotiations as did a proposed provision that included mandatory demand charges.[18]

In March 2017, Illinois also launched the "NextGrid" utility of the future study. This 18 month study will evaluate utility business models and regulatory strategies that will help the grid be more flexible and efficient.[19]

Important sources/references:

- ICC Order, "Annual Formula Rate Update and Revenue Requirement Reconciliation under Section 16-108.5 of the Public Utilities Act," Docket 16-0259, December 6, 2017.
  - Most recent approved formula rate update for ComEd (before amendments in March 2017).
- Illinois Senate Bill 2814, "Future Energy Jobs Act," passed December, 7, 2016. Accessed 6/8/2017 https://legiscan.com/IL/text/SB2814/2015.
  - The Future Energy Jobs Act extended formula rates in Illinois through 2022.

[14] ComEd, "ComEd Customers to See Energy Efficiency Savings," April 7, 2017, accessed June 9, 2017, available at: https://poweringlives.comed.com/comed-customers-to-see-energy-efficiency-savings/.

[15] UtilityDIVE, "Why Exelon's mammoth Illinois energy bill could set a precedent for other states," December 12 2016, accessed June 8, 2017, available at: http://www.utilitydive.com/news/why-exelons-mammoth-illinois-energy-bill-could-set-a-precedent-for-other-s/432089/.

[16] UtilityDIVE, "Why Exelon's mammoth Illinois energy bill could set a precedent for other states," December 12 2016, accessed June 8, 2017, available at: http://www.utilitydive.com/news/why-exelons-mammoth-illinois-energy-bill-could-set-a-precedent-for-other-s/432089/.

[17] ICC, "Verified Petition to Initiate Annual Formula Rate Update and Revenue Requirement Reconciliation Under Section 16-108.5 of the Public Utilities Act," Docket 17-0196, April 13, 2017; Future Energy Jobs Act, "2017 ComEd Bill Changes for Residential Customers," accessed June 8, 2017, available at: http://www.futureenergyjobsact.com/resources/pdf/Bill-Explainer-Handout.pdf.

[18] UtilityDIVE, "Why Exelon's mammoth Illinois energy bill could set a precedent for other states," December 12 2016, accessed June 8, 2017, available at: http://www.utilitydive.com/news/why-exelons-mammoth-illinois-energy-bill-could-set-a-precedent-for-other-s/432089/.

[19] UtilityDIVE, "Illinois Launches NextGrid Utility of the Future Study," March 23, 2017, accessed June 19, 2017, available at: http://www.utilitydive.com/news/illinois-launches-nextgrid-utility-of-the-future-study/438716/.

ATCO Electric and ATCO Gas

Electricity Distribution and Natural Gas Distribution Utilities
Alberta, Canada

THE Brattle GROUP

Multi-Year Rate Plan and Capex Rider/Tracker

Ratemaking Characteristics:

Note: The below PBR framework is applied to all electricity and natural gas distribution utilities in Alberta. Only the specific programs that fall under the K-, Y-, and Z-factors differ from one utility to the other.

- **Business segments:** Electricity distribution and natural gas distribution.
- **Ratemaking methodology:** MRP with indexing – price cap for electric distribution and revenue per customer cap for natural gas distribution.
- **Length:** 5 years.
- **Decoupling:**

  Electric: None.

  Gas: There is partial decoupling for gas distribution – the utility is protected for weather related risks, and for declining use per customer through the revenue per customer cap, but is at risk for changes in number of customers.
- **Ratemaking Scope:** All electricity/natural gas distribution expenditure, excluding some capital and pass-through items that are provided for via the K-factor (capital riders/trackers), Y-factor, and Z-factor (pass-through costs).
- **Rate adjustments (between rate cases):**

  An annual adjustment of inflation less a productivity factor (I – X) is applied to rates for ATCO Electric and to revenue per customer for ATCO Gas.

  The I-factor is updated each year and is composed of the Alberta average weekly earnings index – weighted at 55% – and the Alberta consumer price index – weighted at 45% – for the previous year (June to July).[1]

  The X-factor is based on an involved "total factor productivity" study using data on U.S. electric utilities. The current (2013-2017) X-factor also includes a 0.2% stretch factor, which acts to slow the price or revenue cap growth determined in the I - X mechanism. The Alberta Utilities Commission (AUC) believed that an immediate increase in productivity growth could be expected as companies move from cost-of-service regulation to PBR. The 0.2% stretch factor, applied to all Alberta utilities is meant to share the benefits of this potential immediate growth between utilities and their customers.[2]

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[1] Alberta Utilities Commission (AUC) Decision 2012-237, "Rate Regulation Initiative, Distribution Performance-Based Regulation," Proceeding 566, September 12, 2012, p. 52 ¶ 251.

[2] Ibid, p. 98 ¶ 468, p. 100 ¶ 479, and p. 104 ¶ 499.

- **Regulatory / Legislative Authority:**

  The Alberta distributors' current PBR plan was created on the basis of a regulatory decision. Prior to the current plan, rates for all Alberta distribution utilities except for ENMAX Power Corporation (EPC) were regulated under a traditional cost-of-service methodology.[3] In February 2010, the AUC announced that it would begin a "rate reform" initiative in order to implement a form of PBR for electric and natural gas distribution companies in Alberta.[4] In July 2010, AUC Bulletin 2010-20 set out the following principles for distribution PBR, and required all electric and gas distributors aside from EPC to file PBR applications in a generic proceeding:[5]

  1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality
  2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return
  3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time
  4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design
  5. Customers and the regulated companies should share the benefits of a PBR plan

  The resulting generic distribution PBR plan is currently in place for ATCO Electric and ATCO Gas (as well as most other Alberta distribution utilities) through 2017. A subsequent PBR plan has also been approved for 2018 – 2022.[6]

  ATCO (as well as most other Alberta utilities) has had two distribution rate cases with price cap plans for electricity and revenue per customer cap plans for gas since 2013.[7]

- **Reopeners / Off-Ramps**:

  Any party – including the ATCO utilities and the AUC – may file an application to reopen the PBR plan if there is evidence that a revision is needed, such as:

  – Weather normalized ROE that falls 500 basis points above or below the approved ROE in a single year, or 300 basis points for two consecutive years;[8]

  – Significant material contraction/expansion of customers or service territories;[9]

[3] In 2009, EPC had a price cap PBR plan approved for 2007-2013 term for both electric transmission and distribution. See AUC Decision 2009-035.
[4] See "Rate Regulation Initiative Round Table," AUC letter to interested parties, February 26, 2010.
[5] See AUC Bulletin 2010-20, "Regulated Rate Initiative – PBR Principles," July 15, 2010, pp. 2-3.
[6] See AUC Decision 20622-D01-2016, "2016 Generic Cost of Capital," Proceeding 20622, October 7, 2016.
[7] See AUC Decisions 2012-237 and 20414-D01-2016.
[8] AUC Decision 2012-237, p. 161 ¶ 737.
[9] AUC Decision 2012-237, pp. 161-162 ¶ 741.

- Legal or regulatory changes requiring a company to assume default supply obligations, that cannot be dealt with through Z-factor treatment or other mechanisms;[10] and
- Substantial, unforeseen changes in circumstances that cannot be accommodated by the plan.[11]

- **Earnings Sharing Mechanism**: The current PBR plan for the ATCO utilities does not include an Earnings Sharing Mechanism.[12]
- **TPIs:** ATCO Electric and Gas's PBR plans are not combined with any targeted performance incentives.[13]
- **Riders / Trackers:**

  The ATCO utilities' current PBR plans include an extensive capital rider/tracker (K-factor) that covers any revenue requirement increase related to capital additions. The K-factor provides top-up funding for capital programs that grow faster than I – X, effectively on a flow-through basis, but does not "net off" surplus funding for programs growing slower than I – X. In order for a program to fall under the purview of the K-factor, it must meet three criteria:

  - be outside the course of ordinary operations;
  - replace an existing asset or be required by a third party; and
  - have a material effect on finances.[14]

  Each year, ATCO files capital rider/tracker applications for supplemental capital funding requirements. Approved capital rider/tracker placeholders are included on an interim basis in the ATCO utilities' rates, and then later trued-up to amounts approved in compliance filings in following years.[15] For example, ATCO Electric's approved 2015 capital riders/trackers included items such as new extensions, wood pole replacements and life extension, and wild fires mitigation.[16] ATCO Gas's approved 2015 capital riders/trackers included items such as steel mains replacements, a meter relocation replacement program, and cathodic protection.[17]

  Note that the scope of the K-factor in the next plan (2018-2022) has been significantly reduced (see the "Latest discussions on changes to framework" section).

[10] AUC Decision 2012-237, p. 162 ¶ 742.
[11] AUC Decision 2012-237, p. 164 ¶ 753.
[12] AUC Decision 2012-237, p. 178 ¶ 822.
[13] ATCO reports on service quality and reliability performance metrics to the AUC under Rule 002, but there are no TPIs attached.
[14] AUC Decision 2012-237, p. 124 ¶ 586 and p. 126 ¶ 592.
[15] AUC Decision 2013-435, "Distribution Performance-Based Regulation, 2013 Capital Rider/Tracker Applications," Proceeding 2131, December 6, 2013, p. 1 ¶ 4.
[16] See AUC Decision 20369-D01-2015, "ATCO Electric Ltd., 2013-2015 Capital Rider/Trackers Compliance Filing," Proceeding 20369, August 31, 2015 (corrected version of August 19, 2015 decision), p. 2 ¶ 6 – Table 1: Updated K factor amounts.
[17] See AUC Decision 20385-D01-2015, "ATCO Gas, 2013 PBR Capital Rider/Tracker Refiling and True-up and 2014-2015 PBR Capital Rider/Tracker Forecast Compliance Application," Proceeding 20385, August 24, 2015, p. 2 ¶ 8 – Table 1: Updated K factor amounts.

ATCO's current plan also includes a Y-factor and Z-factor to manage flow-through costs and exogenous events that are outside its control, respectively. The ATCO distribution utilities' Y-factor items include recurring, Commission-approved costs, or costs that the company is required to pay to third parties such as the Alberta transmission operator, that are higher than a specified materiality threshold.[18]

ATCO Electric and ATCO Gas, as well as the Alberta Utilities Commission (AUC) and interveners, may apply for Z-factor adjustments during the rate term to account for any costs that were prudently incurred and where the impact of the event(s) was unforeseen, outside of management's control, and higher than a specified materiality threshold.[19]

- **Timeline of the last rate case (for the upcoming rate plan):**
  - Commission announcement initiating latest PBR proceeding: May 8, 2015[20]
  - PBR plan proposals from ATCO Electric and ATCO Gas: March 23, 2016
  - Final decision issued: December 16, 2016 (Errata February 6, 2017)[21]
  - Rebasing application from ATCO Electric and ATCO Gas: April 21, 2017 [22]
  - Rates to be applicable starting: January 1, 2018

Latest discussions on changes to framework:

The most recent generic PBR proceeding[23] for the 2018-2022 term reopened discussions on rebasing, updating the X-factor, and reforming the K-factor.[24] The AUC's decision in this proceeding[25] made the following conclusions:

- Going-in rates will be based on trending of actual costs (e.g., roll the lowest recorded O&M amount (from the 2013-16 period) forward (using I – X) then calculate the revenue requirement).[26]
- The forecast test year rate base will be based on the recorded rate base plus average historical additions, retirements, depreciation.
- The X-factor will be based on a "total factor productivity" study that estimates industry-wide productivity based on US utility data.[27,28]

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[18] AUC Decision 2012-237, p. 131 ¶ 617, pp. 134-135 ¶ 631, and p. 135 ¶ 636. See AUC Decision 2012-237 p. 112 ¶ 535 for more information on how the materiality threshold is calculated.

[19] AUC Decision 2012-237, p. 108 ¶ 517 and p. 110 ¶ 524. See AUC Decision 2012-237 p. 112 ¶ 535 for more information on how the materiality threshold is calculated.

[20] See AUC Bulletin 2015-10, "Generic proceeding to establish parameters for the next generation of performance-based regulation plans – Pre-proceeding conference draft issues list," May 8, 2015.

[21] AUC Decision 20414-D01-2016, "2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities," Proceeding 20414, February 6, 2017 (corrected version of December 16, 2016 decision).

[22] ATCO Electric and ATCO Gas, "2018-2022 Performance Based Regulation Rebasing Application," Proceeding 22394, April 21, 2017.

[23] The generic 2018-2022 PBR plan applies to all distribution utilities in Alberta.

[24] See Attachment to AUC Bulletin 2015-10 – "Pre-proceeding conference draft issues list."

[25] See AUC Decision 20414-D01-2016.

[26] AUC Decision 20414-D01-2016, pp. 12-13 ¶ 53.

- The K-factor will be significantly curtailed, basing the rider/tracker on trending of historical average capital expenditures rather than a flow-through of costs, and requiring programs with headroom to be netted off. There will be no additional revenue allowed during the plan term except for entirely new kinds of assets required by third parties.[29]

Important sources/references:

- AUC Bulletin 2010-20, "Regulated Rate Initiative – PBR Principles," July 15, 2010.
  - Announcement from the AUC describing its perspective on the goals of its PBR initiative for Alberta distribution.
- AUC Decision 2012-237, "Rate Regulation Initiative, Distribution Performance-Based Regulation," Proceeding 566, September 12, 2012.
  - Decision on PBR plans for the 2013-2017 term for all Alberta distribution utilities except for ENMAX Power Corporation.
- AUC Decision 20414-D01-2016, "2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities," Proceeding 20414, February 6, 2017 (corrected version of December 16, 2016 decision).
  - Decision on PBR plans for the 2018-2022 term for all Alberta distribution utilities.

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[27] The study uses US utility data as there was no usable data available in Canada.
[28] See AUC Decision 20414-D01-2016, p. 22 ¶ 89. This study has proved controversial (although the methodology was determined in the prior rate case after a long proceeding with multiple experts involved, updating this study with new data also proved to be a source of disagreement between the various parties).
[29] See AUC Decision 20414-D01-2016, p. 52 ¶ 198 and pp. 68-69 ¶ 255.

Ausgrid

Electricity Distribution Utility
New South Wales, Australia

THE Brattle GROUP

Multi-year Rate Plan

Ratemaking Characteristics:

- **Business segments**: Electricity distribution.[1]
- **Ratemaking methodology:** Multi-year rate plan with indexing – revenue cap using forecast costs for the five-year period.
- **Length:** 5 years.
- **Decoupling:** Ausgrid has full decoupling – a true-up mechanism ensures that revenues collected are equal to the formula-determined amount.[2]
- **Ratemaking Scope**: All electricity distribution expenditure except for "contingent" projects (see the "Other add-ons to the basic 5-year forecast" section for more details).
- **Rate adjustments (between rate cases):**

  Australia uses the "building block" framework for determining the revenue requirement of distribution utilities. The revenue requirement for each year is calculated at the start of the plan as the sum of forecast O&M, depreciation, return on rate base, and forecast tax (i.e., blocks). The forecasted rate base includes forecast capex. Forecast O&M are calculated using the "base, step, trend" approach: "base" refers to the last year of recorded O&M, "steps" are known changes, "trend" is expected O&M inflation and growth. Capex, rate base and depreciation are built up from detailed forecasts, reviewed by the Australian Energy Regulator (AER) and its consultants.[3]

  The revenue requirement then evolves with inflation less a smoothing factor (I – X). Target revenue will be adjusted each year by actual inflation (I) plus or minus an X-factor offset. The X-factor is calculated at the start of the plan so that expected revenues (including forecast inflation) have the same net present value as forecast costs and the annual revenue requirement is smooth across the five years (i.e., does not have large changes year-to-year). The X-factor is updated annually to reflect a revised return on debt.[4] Since revenues will be

[1] Ausgrid has a small amount of transmission assets as well, which they include in their distribution proposal.

[2] Ausgrid Determination 2014-19, AER Final Decision, Attachment 14, April 30, 2015, available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2014-19/final-decision.

[3] Ausgrid Determination 2014-19, AER Final Decision, Overview and Attachments 1 and 7, April 30, 2015, available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2014-19/final-decision.

[4] Ausgrid Determination 2014-19, AER Final Decision, Overview, April 30, 2015, p. 22, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2014-19/final-decision, and AER, "Electricity distribution network service providers: Post-tax revenue model handbook," 29 January 2015, section 2.8.

adjusted for actual inflation, if inflation is higher than forecast, Ausgrid will collect more revenue in nominal terms than originally expected.[5]

Regulatory / Legislative Authority:

The National Electricity Law (NEL) was first passed in 1996 as a schedule to the *National Electricity (South Australia) Act 1996 (SA).* It was applied as law to New South Wales in 1997. From 2012-2014, the AER worked on a series of reforms collectively titled "Better Regulation." These reforms focused on, among other things, strengthening the incentive based regulation scheme, which included establishing the rolling incentives and service quality incentives.[6]

- **Reopeners/Off-Ramps:** There are no reopeners in Australian electricity regulation and we are not aware of any past cases a determination has been reopened.
- **Earnings Sharing Mechanisms:**

  See "Rolling Incentives" below for an explanation of the Efficiency Benefit Sharing Scheme and the Capital Expenditure Sharing Scheme. However, note that these schemes do not have the same effect as a typical North American earnings sharing scheme. A North American scheme would typically be based on sharing the difference between authorized and achieved ROE each year. In Australia, the sharing is of the difference between actual and forecast O&M, and actual and forecast capex. It is not possible to compare the sharing factors in a straightforward fashion.
- **TPIs**:
  - *Traditional:* Ausgrid is subject to an incentive scheme that provides additional revenue or penalties if distributors meet certain reliability goals. These goals include reducing the frequency and duration of service interruptions and reducing the wait time on call center services. The amount of additional revenue or penalty is calculated as a percentage of the utility's annual revenue and is proportional to the difference between the utility's performance and the reliability goals.[7]
  - *Emerging:* See "Latest discussions on changes to framework" below for a discussion of the Demand Management Incentive Scheme.
- **Other add-ons to the basic 5-year forecast:**
  - *"Contingent" projects:* Projects that are well-defined but have uncertain need or timing. These projects are identified and costed at the outset, but not yet approved. They have to be described at the start of the period and a triggering event has to be defined. If the trigger event happens during the five-year term, the

[5] Ausgrid Determination 2014-19, AER Final Decision, Attachment 14, April 30, 2015, pp. 14-8 and 14-19, available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2014-19/final-decision.

[6] See AER, "Overview of the Better Regulation reform package," April 2014, for more details.

[7] AER, "Issues paper: Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guidelines," January 2017.

network can request additional revenue at that point. An example of contingent project is an inter-tie upgrade that has not yet received necessary replace an existing asset or be required by a third party; and approvals to go ahead. To date, Ausgrid has not proposed any contingent projects.[8]

– _Rolling incentives:_ The Efficiency Benefit Sharing Scheme and the Capital Expenditure Sharing Scheme adjust for time effects on O&M and capex efficiency. Without these schemes, utilities have an incentive to overspend or underspend depending on how far away the next rate case is. For O&M, utilities would have an incentive to spend more in the 'base year' used to forecast O&M in order to get a higher allowance. For capex, the rate base is only updated every 5 years, so efficiency gains in capex are more valuable the longer amount of time before the next rate base update. Both of these schemes spread out efficiency gains or losses in O&M and capex across the 5-year period and the period following to remove these incentives. Any efficiency gains or losses are borne 30% by the distributor and 70% by network users (in net present value terms).[9] The practical effect of these schemes is that where savings are made in one period, additional savings are "rolled over" into the following period (i.e., an additional reward is provided to the utility in the subsequent period, in the form of additional revenue).

- **Timeline of last rate case:**
  – AER publishes final framework and approach paper: January 31, 2014
  – Application from Ausgrid: May 29, 2014
  – Final decision issued: April 30, 2015[10]
  – Rates to be applicable starting July 1, 2015[11]

Latest discussions on changes to framework:

The AER is currently developing a new program to incentivize managing demand, known as the Demand Management Incentive Scheme. The scheme would provide an incentive for distribution businesses to invest in non-network options related to demand management. There would also be an incentive to reward investment in unproven technologies and solutions. The final scheme is scheduled to be published in October/November 2017.[12]

Important sources/references:

- AER Final Decision, Ausgrid Determination 2014-19, Overview and Attachments, April 30, 2015.
  – Ausgrid's most recent revenue determination.

8 AER, "Contingent projects," https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects, accessed June 5, 2017.

9 AER, "Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers", November 2013, and AER, "Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers," November 2013.

10 Ausgrid Determination 2014-19, AER Final Decision, Overview, April 30, 2015. Ausgrid appealed to the Australian Competition Tribunal in May 2015. The tribunal ruled to set aside the AER's revenue determination in February 2016.

11 Due to some changes to distribution regulation in 2012, the 2014-19 regulatory period was split into a transitional period in 2014-15. The 2014-15 period was subject to a placeholder determination, which was adjusted in the full 2015-19 determination.

12 AER, "Demand Management Incentive Scheme and Innovation Allowance Mechanism," January 4, 2017.

- AER, “Demand Management Incentive Scheme and Innovation Allowance Mechanism,” January 4, 2017.
  - Consultation paper about the Demand Management Incentive Scheme.
- AER, “Overview of the Better Regulation reform package,” April 2014.
  - Summary of a package of reforms to network regulation, including stronger incentive-based regulation schemes.

Northern Powergrid (NPg) and Northern Gas Networks (NGN)

Electricity Distribution & Natural Gas Distribution Utilities
Northeast England, U.K.

THE Brattle GROUP

Multi-Year Rate Plan and TPIs

Ratemaking Characteristics:

Note: The below PBR framework is applied to all electricity and natural gas distribution utilities in Great Britain. Only the specific performance incentives and uncertainty mechanisms differ from one utility to the other.

- **Business segments:** Electricity distribution and natural gas distribution, respectively.
- **Ratemaking methodology:** MRP with indexing – revenue cap.
- **Length:** 8 years.
- **Decoupling:** Both NPg and NGN have revenue decoupling due to the revenue cap.
- **Ratemaking Scope:** All electricity/natural gas distribution expenditure, excluding pass-through and exogenous costs that are provided for via uncertainty mechanisms (see the "Riders/Trackers" section).
- **Rate adjustments (between rate cases):**

  NPg and NGN[1] currently operate within a price control term labeled "RIIO-ED1" and "RIIO-GD1", which run from April 2015 to March 2023 and April 2013 to March 2021, respectively. Under the RIIO approach, base revenues for each year are set using a "totex" (i.e., total expenditures) approach, rather than distinguishing between opex and capex. Ofgem uses historical costs, performance data, and distributor forecasts to model distributor expenditures and eventually determine totex allowances for the rate term.[2]

  Base revenues are indexed to inflation (RPI)[3] and are adjusted each year for an updated cost of debt allowance and for several incentive and efficiency sharing mechanisms (see the "TPIs" section). Revenues may also be adjusted according to a set of uncertainty mechanisms that are forecast at the start but finalized during the course of the rate term (see the "Rider s/Trackers" section).[4]

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1 Although these utilities have similar names and operate in similar regions of the UK, they are not owned or operated by the same company.

2 See Office of Gas and Electricity Markets (Ofgem), "RIIO-ED1: Final determinations for the slow-track electricity distribution companies," November 28, 2014, p. 23 and Ofgem, "RIIO-GD1: Final Proposals – Overview," December 17, 2012, pp. 24, respectively.

3 Ofgem defines the RPI as:

> "an aggregate measure of changes in the cost of living in the UK. It differs from the CPI in that measures changes in housing costs and mortgage interest repayments, whereas the CPI does not, they are calculated using different formulae and have a number of other more subtle differences."
>
> See Ofgem, "Glossary of terms: RPI-X@20 review," October 2010, available at: https://www.ofgem.gov.uk/ofgem-publications/51906/rec-glossary.pdf.

4 See Ofgem (2014), p. 10 and Ofgem (2012), p. 30, respectively.

- **Regulatory / Legislative Authority:**

  Beginning in 2008, Ofgem conducted a detailed review of energy network regulation titled "RPI-X@20". Following this review, Ofgem established the RIIO framework for setting price controls in October 2010.[5]

  NPg and NGN have each had one rate case under the RIIO framework since 2012.[6]

- **Reopeners / Off-Ramps:**

  Both NPg and NGN have several reopeners and/or triggers for reviewing and revising their PBR plans during the rate term to account for specific events (e.g., changes in tax laws) or projects (e.g., rail electrification), typically categorized as one of many "uncertainty mechanisms" (see the "Riders/Trackers" section).

- **Earnings Sharing Mechanism:**

  Both NPg and NGN have efficiency incentive rates, or sharing factors, that set the rate at which the companies earn profits from underspending or bear costs from overspending (see the "TPIs" section). However, the calculation of sharing is fundamentally different from ESMs implemented in North America: no attempt is made to measure *earnings*. These mechanisms share "savings", measured as the difference between anticipated expenditure and actual expenditure.[7]

- **TPIs:**

  All U.K. distributors must meet specified output targets, and will receive financial rewards or penalties based on their performance:

  – NPg's outputs and associated incentives include (but are not limited to):[8]

    - compliance with safety legislation – no financial incentive (non-compliance is subject to action by the Health and Safety Executive),
    - meet customer satisfaction goals (via surveys) – reward of +/- 0.5% of base revenue,
    - "time to connect" smaller connection customers – maximum reward of 0.4% of base revenue,[9]
    - reduction in electricity losses – discretionary reward of up to £32m available across electric distributors, distributed in three tranches over rate term,[10]
    - reliability (supply interruptions) – a symmetrical incentive with a maximum reward or penalty of 250 basis points on return on regulatory equity per year,[11]
    - stakeholder engagement – maximum reward of 0.5% of base revenue.[12]

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5 Ofgem (2010).

6 See Ofgem (2014) and Ofgem (2012), respectively.

7 Ofgem, "Handbook for implementing the RIIO model", October 4, 2010, p. 84.

8 See Ofgem (2014), pp. 71-72 and Ofgem, "Strategy decision for the RIIO ED-1 electricity distribution price control – Outputs, incentives and innovation," March 4, 2013.

9 Ofgem (2013), p. 80.

10 Ofgem (2013), p. 43.

11 Ofgem (2013), pp. 32-33.

- NGN's outputs and associated incentives include (but are not limited to):[13]
  - reporting on and creation of new standards and arrangements for biomethane capacity connections – reward of up to £12m,
  - reduction in gas transport losses – reward includes, among other items, the introduction of a rolling incentive mechanism,
  - meet customer satisfaction goals (via surveys) – incentive of +/- 1% of allowed revenue,
  - connection of low-income households – discretionary reward available,
  - reduction in safety risk – review of performance at end of RIIO-GD1, and
  - maintaining operational performance – review of performance at end of RIIO-GD1.

Both electric and gas distributors also have access to several forms of innovation funding, including the Network Innovation Competition (NIC), Network Innovation Allowance (NIA), and Innovation Roll-out Mechanism (IRM).[14]

NPg received a NIA of 0.6% of their base revenue each year,[15] and NGN received a NIA of 0.7% of their base revenue each year.[16]

The RIIO Framework also applies several incentives to motivate electric distributors to submit accurate cost forecasts.

- The Information Quality Incentive (IQI) provides financial rewards or penalties depending on how close a distributor's forecast is to Ofgem's perspective of efficient expenditure, and how close a distributor's actual spending is to its forecast or Ofgem's modelled view. Based on its IQI score, NPg received a total upfront financial reward of £2.7m, which will remain fixed if the utility spends in line with its final determinations allowance.[17] NGN received a reward of 1.3% of totex based on its IQI score.[18] The IQI is designed to provide an incentive to control costs during the plan term while simultaneously providing an incentive to prepare an unbiased forecasts of costs before the plan starts.
- The efficiency incentive rate is the share of under or overspend that the utility retains or bears. NPg has an incentive rate of 55%,[19] and NGN has an incentive rate of 64%.[20]

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12 Ofgem (2013), p. 74.

13 Ofgem (2012), p. 20.

14 Ofgem (2012), p. 21 and Ofgem (2013), p. 97.

15 Ofgem (2014), p. 55.

16 Ofgem (2012), p. 22.

17 If NPg spends in line with its (higher) forecast, it will receive a penalty that brings its total incentive down to –£115.2m; if NPg spends in line with Ofgem's modelled view, it will instead receive a total incentive of £43m. See Ofgem (2014), pp. 37-38.

18 Ofgem (2012), pp. 28-29.

19 Ofgem (2014), p. 73.

20 Ofgem (2012), p. 29.

- **Riders / Trackers:**

  The RIIO framework employs several uncertainty mechanisms[21] to pass through or otherwise account for costs that utilities have little control over.

  NPg's uncertainty mechanisms include (but are not limited to): a pass through of business rates, Ofgem license fees, and smart meter Data Communications Company fixed costs; a volume driver for smart meter roll-out costs; reopeners for street works, load-related expenditure, and rail electrification; and a trigger for changes in taxes.[22]

  NGN's uncertainty mechanisms include (but are not limited to): a pass-through of business rates, license fees, costs related to gas theft, and gas prices related to shrinkage; reopeners for street works, enhanced physical site security, and smart metering; revenue drivers for mains replacement; and a trigger for tax legislation.[23]

- **Timeline of the last rate cases:**
  - RIIO framework for price controls established: October 4, 2010[24]
  - Final determinations for gas distributors under RIIO-GD1: December 17, 2012[25]
  - Gas rates to be applicable starting: April 1, 2013
  - Final determinations for "slow-track" electric distributors under RIIO-ED1: November 14, 2014[26]
  - Electric rates to be applicable starting: April 1, 2015

Latest discussions on changes to framework:

In February 2017, the Chief Executive of Ofgem gave a speech at a stakeholder feedback event on the annual Forward Work Programme that noted that the agency may consider shortening the rate term in the next round of RIIO plans, given the challenge of long-term forecasts with the "scale and unpredictability of change [that] the energy system is going through."[27]

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[21] Utilities may also have some discretionary funding available under the RIIO incentives schemes. For example, NPg and other electric distributors are provided a conditional allowance to improve service reliability for the "worse served" customers, on a use it or lose it basis. Ofgem (2013), p. 36.

[22] Ofgem (2014), p. 73.

[23] Ofgem (2012), p. 33.

[24] Ofgem (2010).

[25] Ofgem (2012).

[26] Under RIIO, Ofgem considers utility business plans of high quality that provide good value for customers for "fast-tracking" treatment, where Ofgem accepts the business plan as submitted without need for revisions and concludes the company's rate plan review early. If a plan is not accepted for fast-tracking, it moves on to the "slow-track" timeline.

NPg is one of ten electricity distributors in the UK whose rate plan was determined on a "slow-track" timeline; only Western Power Distribution's rate plan was concluded on an earlier, "fast-track" timeline (with a determination for its four distributors published on February 28, 2014). See Ofgem, "Decision to fast-track Western Power Distribution," February 28, 2014 and Ofgem (2014). No gas utilities were considered for fast-tracking under RIIO-GD1.

[27] Speech by Dermot Nolan, Forward Look Event on draft annual Forward Work Programme, February 9, 2017, available at: https://www.ofgem.gov.uk/publications-and-updates/dermot-nolans-speech-annual-forward-work-programme-event.

Important sources/references:

- Ofgem, “Handbook for implementing the RIIO model”, October 4, 2010.
  - Ofgem policy document establishing and describing the RIIO model.
- Ofgem, “RIIO-ED1: Final determinations for the slow-track electricity distribution companies,” November 28, 2014.
  - Ofgem decision on the RIIO-ED1 price control for slow-track electricity distributors (including NPg).
- Ofgem, “RIIO-GD1: Final Proposals – Overview,” December 17, 2012.
  - Ofgem decision on the RIIO-GD-1 price control for all gas distributors (including NGN).

Public Service Electric & Gas (PSE&G)

Electricity & Natural Gas Distribution Utility
New Jersey, USA

THE Brattle GROUP

Focused Case Study: Rider/Tracker

Capital Infrastructure Investment Plan (CIIP)

(Recovered through Capital Adjustment Charge, CAC)

- **Background:** In January of 2009 (Docket GO 09010050, and EO 09010049) PSE&G proposed the Capital Infrastructure Investment Plan (CIIP) including a Capital Adjustment Charge to recover the costs.
- **Additions/Expansions of Riders/Trackers**: PSE&G proposed to expand its CAC in 2010 but was denied
- **Programs Included:** CIIP's covers 38 specific qualifying projects, such as environmental regulation and facility upgrades.
- **Amount**: $694 million - $421 in electric and $273 in gas.
- **Length of Time:** 3 years, starting April 2009.

  Projects are reviewed, and then rolled into the base rates.

  CAC terminated following roll-in to base rates.
- **Recovery:** CAC is recovered through a Capital Adjustment Factor equal to the percentage increase in each part of the PSE&G's distribution rates needed to create revenues sufficient to meet the annual revenue requirement associated projects covered under CAC.
- **Reconciliations:** Over and under recovery are calculated monthly and subject to deferred accounting. An annual filing provides reconciliation.
- **Stated Purpose:** CAC is designed to recover the revenue requirements associated with the acceleration of electric capital expenditures in the areas of distribution infrastructure related to improvement in reliability and operation of the system and capital expenditures related to energy efficiency infrastructure improvements.
- **Stay Out Requirements:** None. PSE&G filed a rate case a year after they opened their docket on the CIIP and their investments through Dec 31, 2009 were rolled into base rates. The CAC stipulation had included a requirement that PSE&G file a base rate petition between April 2009 and April 2011.
- **Detail Required:** Quarterly filing will include capex for each project and related job growth. A Gantt chart showing the status of the projects, tasks completed, percentage of projects completed is also required. Planned and actual expenditures on Non-Qualifying projects also required. The annual filing will contain the reconciliation, projected revenue requirements for the upcoming 12-month period, and minimum filing requirements (MFRs). The MFRS cover PSEG's income statement for the last 12 months, capital budget, summary of each project and it's expenditures and metric, project timeline, FTE equivalent jobs, list of funds or credits received (from federal, state, county or municipal entity), interest rate and interest expense.
- **Related PIMs:** None.

- **Consistency Across Utility/State:** Not consistent. Atlantic City Electric, Jersey Central Power&Light/Connectiv, and Orange Rockland Electric do not have riders/trackers in use.
- **Contingencies Addressed:** None.
- **Legislative Mandate vs. Regulatory Requirement:** The CIIP was developed in response to the Governor's Economic Stimulus Plan in 2008, which directed the New Jersey Board of Public Utilities to implement policy that would support long-term economic growth.
- **Handling Deviations from Approved Plan:** PSE&G is allowed to eliminate or substitute projects with board approval

Public Service Electric & Gas (PSE&G)

Electricity & Natural Gas Distribution Utility
New Jersey, USA

THE Brattle GROUP

Focused Case Study: Energy Strong Adjustment Mechanism (ESAM) Rider/Tracker

- **Background:** The Energy Strong Adjustment Mechanism went into effect in 2014 as the recovery mechanism associated with PSE&G's Energy Strong Program, which the utility put in place as part of the NJ BPU's Storm Mitigation Proceeding (Dockets EO13020155 and GO13020156).
- **Additions/Expansions of Riders/Trackers**: Not expanded.
- **Programs Included:** Covers substation flood mitigation, grid reconfiguration strategies, and smart grid for the electric business. For the gas business it covers metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas.
- **Amount**: $1 billion capital expenditure ($0.6 billion for electric and $0.4 for gas). Programs are specified in detail, which PSE&G will report on. O&M is excluded from recovery via ESAM.
- **Length of Time:** ES expenditures were made in 2014-2017. Cost recovery through base rate adjustments.
- **Recovery:** ES project costs are recovered through expedited rate adjustments, conducted semi-annually for electric projects and annually for gas projects. The electric portion of the ESAM works as follows:

  ES costs placed into service by 11/30/2014 go into base rates 3/1/2015
  ES costs placed into service by 5/31/2015 go into base rates 9/1/2015
  ES costs placed into service by 11/31/2015 go into base rates 3/1/2016
  ES costs placed into service by 5/31/2016 go into base rates 9/1/2016
  ES costs placed into service by 11/30/2016 go into base rates 3/1/2017
  ES costs placed into service by 5/31/2017 go into base rates 9/1/2017
- **Reconciliations:** Quarterly reports for expenditures, broken down by materials and other costs, and for performance are required. All program costs will be reviewed for prudency in the next rate case if they are not rolled into the test year. PSE&G may make additional roll-in filings if any ES costs fall outside of the established roll-in schedule. Also, $220 million of the total ES costs are not included in the roll-in adjustment and will be recovered in PSE&G's next base rate case (which will be no later than November 2017).
- **Stated Purpose:** ESAM was specifically developed in response to requests from governmental agencies to mitigate the impact of major weather events, as the State had recently experienced long duration power outages with roughly 2 million customers affected to some extent.
- **Stay Out Requirements:** None, PSE&G was required to file its next rate case no later than 2017.
- **Detail Required:** The BPU checks the PSE&G's performance in terms of spending in the agreed upon areas prior to incorporating costs into the ESAM. In addition, the BPU requires that PSE&G report certain areas of performance although there are no penalties associated with failure to meet specific targets. The areas of reporting include Customer Average Interruption Duration Index (CAIDI) Major Event performance on a circuit,

operating level and system wide basis. PSE&G also needs to report its progress in reducing its active leak inventory associated with its natural gas infrastructure.

- **Related PIMs:** There are 2 penalty areas associated with the Gas ESAM:
    1) PSE&G is required to reduce leak inventory by 10% annually for each of 2014, 2015 and 2016. If it cannot, it must incur additional costs (at its own expense) to reach the goal.
    2) PSE&G is required to reduce water infiltration during the ten years following deployment. If it does not, it is required to incur additional costs (at its expense) to reach this goal.
- **Consistency Across Utility/State:** New Jersey Natural Gas has a New Jersey Reinvestment in System Enhancement rider/tracker for storm hardening projects. South Jersey Gas has a Storm Hardening and Reliability Program for replacement of low pressure mains, removal of regulator stations, and installation of excess flow valves in coastal areas.
- **Contingencies Addressed:** None.
- **Legislative Mandate vs. Regulatory Requirement:** Following Superstorm Sandy the Board of Public Utilities issued an Order directing utilities to develop cost-benefit of infrastructure updates but did not specific cost recovery mechanism.
- **Handling Deviations from Approved Plan:** No direct terms addressing deviations.

Pacific Gas & Electric Company (PG&E)

Fully-integrated Electricity & Natural Gas Utility
California, USA

THE Brattle GROUP

Focused Case Study: Rider/Tracker

Pipeline Safety Implementation Plan

(Recovered through Implementation Plan Rate)

- **Background:** The CPUC approved PG&E's Pipeline Safety Implementation Plan in 2012 (Docket 12-01-2007). PG&E had already incurred costs on this program prior to rider/tracker approval, which were not allowed to be recovered under the riders/trackers.
- **Additions/Expansions of Riders/Trackers**: None.
- **Programs Included:** The program is broken into categories for Pipeline Modernization Program, Valve Automation Program, Pipeline Records Integration Program, Interim Safety Enhancement Measures, and Program Management Office.
  The investments were approved to achieve pressure testing of 783 miles of pipeline, replacement of 186 miles of pipeline, installation of 228 automated valves, and upgrades to 199 miles of pipeline to allow for in-line inspection.
- **Amount**: Total revenue requirements for Pipeline Safety Implementation riders/trackers is $299 million.
- **Length of Time:** 3 year program (2012-2014).
- **Recovery:** The costs of the plan are recovered through a rider/tracker (referred to as a new "rate component" that is included in the transportation charges) called the Implementation Plan Rate. Costs are recovered by annual adjustments to annual revenue requirement. Recovery is through a volumetric adjustment.
- **Reconciliations:** Implementation Plan capex and O&M costs were tracked in a one-way (downward) balancing account through December 31, 2014. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True-Up Filing, allocated 59.5% to the core class and 40.5 % to the noncore class. Annual adjustments to revenue requirements.
- **Stated Purpose:** The CPUC was motivated to approve the Pipeline Safety Implementation rider/tracker as a means to achieve higher safety standards while striking the right balance between the share of costs borne by PG&E shareholders and those borne by ratepayers. The Pipeline Safety Implementation rider/tracker was implemented following the San Bruno event in 2010.
- **Stay Out Requirements:** None.
- **Detail Required:** Requirements for compliance filings include comparisons of actual versus authorized cost for each work project, explanations of significant deviations, and schedule and prioritization changes. The Commission developed a detail form of 29 questions covering issues such as procurement policies and quality assurance practices. Filings will be posted quarterly to the PG&E website so that parties may review this information and may request such Commission action by motion as needed.
- **Related PIMs:** No formal PIMs, but significant filing requirements and opportunity for CPUC to intervene.

- **Consistency Across Utility/State:** SDG&E and SCE have Safety Enhancement Capital Cost Balancing Accounts to cover replacement of mains that fail pressure tests or that cannot be pressure tested as well as trackers for smart grid, solar, and storage investments.
- **Contingencies Addressed:** PG&E requested and received a degree of flexibility for its Pipeline Safety Implementation Plan. Adjustments to deployment can be made "based on sound engineering data" that further the plan but overall PG&E must adhere to the objectives, scope, and budget. (PG&E also requested but was denied a contingency for cost over runs.)
- **Legislative Mandate vs. Regulatory Requirement:** Neither.
- **Handling Deviations from Approved Plan:** Over-runs in expense and capital cannot be recorded in the balancing account.

Connecticut Light and Power (Eversource)

Electricity Distribution Utility
Connecticut, USA

THE Brattle GROUP

Focused Case Study: Rider/Tracker

System Resiliency Plan (SRP)

(Recovered through Federally Mandated Congestion Charge, FMCC)

- **Background:** CT Public Utilities Regulatory Authority (PURA) approved CLP's System Resiliency Plan (Docket 12-07-06) in January 2013.
  Recovery of SRP was to be through a rider/tracker already in place: FMCC.
- **Additions/Expansions of Riders/Trackers**: Initial SRP was approved in 2013, with a 5 year term (2013-2017). Expanded in 2015; additional cost covered over 3 year term (2015-2017).
- **Programs Included:**
  Initial Plan: Maintenance Trimming, Structural Hardening, System Automation
  Additional Plan: Pole Integrity, System Automation & Grid Modernization (i.e. smart switches and DSCADA upgrading), Substation Security, Substation Flooding, Infrastructure (i.e. resiliency of lines), and Vegetation Management.
- **Amount**: Initial SRP: Investments of $258 million on Capex and $42 million in O&M over 5 years.
  Additional SRP: Investments of $130 million in Capex and $7 million in O&M over three years.
- **Length of Time:**
  Initial Plan: 5 Years, 2013-2017.

  Additional: 3 years, 2015-2017.

  SRP and recovery via FMCC ends in 2017.
- **Recovery:** The System Resiliency Plan is recovered through the existing non-bypassable FMCC. The total FMCC thus covers more than SRP costs. Annual revenue requirements for the 5 years of SRP are recovered through the FMCC, and then revenue requirements are incorporated into base rates.
- **Reconciliations:** Reconciliations are semi-annually. If reconciliations needed are material (≥ 1 mil per kWh) immediate adjustments to FMCC charge can be made without waiting for the next FMCC hearing.
- **Stated Purpose:** SRP reflects programmatic work to upgrade CLP's aging system components; work on such is longer than a single year. Reason for rider/tracker cost recovery mechanism not stated.
- **Stay Out Requirements:** Two year rate freeze (April 2012- December 2014) approved at the same time as the initial SRP (within the Merger agreement discussed below).
- **Detail Required:** CLP is required to provide an annual report on its system resiliency projects and vegetation management on a summary basis and by circuit. In 2013 (during expansion), reporting requirement was reduced in terms of complexity and provided more time for reporting.
- **Related PIMs:** None. CT has PIMs in place for gas and electric, but they are not tied to this program.

- **Consistency Across Utility/State:** Not very consistent. Other major IOU in CT (United Illuminating) does not have a rider/tracker that recovers resiliency investments.
- **Contingencies Addressed:** None.
- **Legislative Mandate vs. Regulatory Requirement:** SRP was a requirement associated with merger approval (CLP + NSTAR.)
- **Handling Deviations from Approved Plan:** No other provisions other than reconciliation.

PECO (Exelon)

Electricity & Natural Gas Distribution Utility
Pennsylvania, USA

THE Brattle GROUP

Focused Case Study: Rider/Tracker

Long Term Infrastructure Plan (LTIP)

(Recovered through Distribution System Improvement Charge, DSIC)

- **Background:** The Distribution System Improvement Charge (DSIC) for electric cover specific programs included in PECO's Long Term Infrastructure Plan (LTIP) (Docket P-2015-2471423 in October 2015).
  DSIC for gas (Docket P-2013-2347340).

  This summary covers Electric.

- **Additions/Expansions of Riders/Trackers**: No expansion yet.
  May be expanded to include additional projects (i.e., microgrid and distributed generation) also included in PECO's LTIP. Expansion of DSIC would involve PECO filing a Petition for Major Modification.

- **Programs Included:** The LTIP programs included under the electric DSIC are: storm hardening and resiliency measures; underground cable replacement; building substation retirements; and facility relocations.

- **Amount**: $324.3 million- $274.3 million for reliability projects and $50 million for facility relocation.

- **Length of Time:** The investment plan covers 5 years: 2016-2020.

- **Recovery:** The DSIC is calculated as:

DSI	=	[(DSI * PTRR)+Dep+e]/ PQR
DSI	=	Original cost of eligible distribution system improvement projects net of accrued depreciation.
PTRR	=	Pre-tax return rate applicable to DSIC-eligible property.
Dep	=	Depreciation expense related to DSIC-eligible property.
e	=	Amount calculated under the annual reconciliation feature or Commission audit.
PQR	=	Projected quarterly revenues for distribution service (including all applicable clauses and riders/trackers) from existing customers plus revenue from any customers which will be acquired by the beginning of the applicable service period.

  The DSIC is terminated with the development of new base rates with DSIC-eligible plant rolled into them.

- **Reconciliations:** The DSIC is updated quarterly with annual reconciliations.

- **Stated Purpose:** No specific text found describing purpose of using a rider/tracker.

- **Stay Out Requirements:** None. PECO was required to have filed a base rate case within months of the DSIC approval.

- **Detail Required:** The Long Term Infrastructure Plan (LTIP) was required to have 5 years of baseline data on several reliability factors.

- **Related PIMs:** None.
- **Consistency Across Utility/State:** Very Consistent. All PA utilities filing a DSIC due to Act 11 (see below) use the same model tariff Commission provides as a format. Several utilities in PA have the same DSIC.
- **Contingencies Addressed:** The DSIC comes with "customer safeguards": a 5.0% cap on the total amount of distribution revenue that can be collected through the DSIC by PECO as determined on an annualized basis and termination of the DSIC if PECO's most recent earnings report shows that PECO is earning a rate of return that exceeds the allowable rate of return used to calculate its fixed costs under the DSIC.
- **Legislative Mandate vs. Regulatory Requirement:** Legislative- Act 11 of 2012 (Act 11) provides utilities with the ability to implement a Distribution System Improvement Charge (DSIC) to recover reasonable and prudent costs incurred to repair, improve or replace certain eligible distribution property that is part of the utility's distribution system.
- **Handling Deviations from Approved Plan:** None.