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Performance-Based Regulation Options

White Paper for the Michigan Public Service Commission

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1. Introduction

1.1. Basics of PBR

Performance-based regulation (PBR) is an option for regulators and utility executives interested in changing utility motivation. It differs from traditional cost-of-service regulation by recompensing utilities based upon their performance outputs and rewarding performance beyond business as usual. PBR enables regulators to reform hundred-year-old regulatory structures to meet the challenges of grid modernization and a transforming power sector. Innovative technologies are transforming the way electricity is generated, delivered, and consumed. Electricity customers are increasingly empowered, and have new ways to interact with the electric grid. These changes in the electric energy system and customer capacities means that there is a need to reform traditional cost-of-service regulation, and PBR incentivizes utilities to do so.

Performance-Based Regulation provides a regulatory framework to connect goals, targets and measures to utility performance, executive compensation and investor returns. For some enterprises, PBRs determine utility revenue or shareholder earnings based on specific performance metrics and other non-investment factors. For utilities of all types, PBR can strengthen the incentives of utilities to deliver value to customers.

Performance Incentive Mechanisms (PIMs) are a component of a PBR that adopt specific metrics, targets, or incentives to effect desired utility performance that represent the priorities of the jurisdiction. PIMs can be specific performance metrics, targets, or incentives that lead to an increment or decrement of revenues or earnings around an authorized rate of return to strengthen performance in target areas that represent the priorities of the jurisdiction.

PBR and PIMs have great value for the electric industry when designed well, and can be applied to many different situations. PBR should be tailored to the needs and goals of each jurisdiction, and perhaps each utility, to most effectively achieve the needs of a 21st century power grid in that jurisdiction.

Multi-year rate plans, a first effort at PBR, were first used in the 1980s for railroads, telecommunications, and other industries facing competition and changing demand, and were introduced for U.S. electric utilities in the 1990s. The purpose of these plans was to motivate efficient operations, and thus low-cost service, while maintaining reliability and customer service. Traditional cost-of-service (COS) regulation essentially assumes that sales growth is a predictor of cost growth - an assumption that today is clearly flawed, at least in the short run. To address this, PBR is often explicit in allowing utilities to earn higher revenue if they become more efficient by cutting cost and continuing to provide quality service.[1] Cost cap regulation, a form of PBR, sets utility revenue over a number of years and then allows the utility to retain all or some portion of cost savings from operating very efficiently.

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[1] Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 35.

This paper examines the role that PBR can play in the future of utility incentive regulation, with a focus on applicability to Michigan. Section 2 discusses the United Kingdom's RIIO mechanism and lessons learned; Section 3 covers cost cap regulation; Section 4 discusses PBR for energy efficiency; and Section 5 briefly summarizes some innovative PBR approaches.

1.2. Characteristics of successful PBR mechanisms

For a performance system to be valuable, it should associate utility outputs with desired outcomes. Desired outcomes may flow from statute, or be discerned from social and political discourse. It is up to the regulator to interpret and structure outcomes to performance regulation. Further, it will focus on priority outcomes and reward those utility activities that produce outputs that achieve those outcomes. For example, environmental outcomes (i.e., clean air, clean water, sound land use) are influenced by utility performance. A state may wish to motivate its utilities with rewards if they achieve certain environmental performance standards (i.e. the outputs).

A performance system should be manageable for the regulator. Factors that promote the regulator's ability to supervise a performance system include:

Experience with the metrics—If the regulator is familiar with the output activity and utility performance, a reward system can be set with confidence.

Transparent metrics— Metrics should be clear (i.e. not require subjective analysis to interpret), consistent across utilities and able to be voluntarily reported.

Periodic reports—If the regulator stays in touch with utility performance system over time, there is less likelihood of misunderstandings when it is time for final reports and reward calculations.

Openness to change—A form of regulation relying more on measuring effectiveness against public interest outcomes and utility activity outputs will need to spend less time focusing on inputs – how the utility is doing its many jobs. Also, this approach is designed to promote innovation, so regulators can expect to see new methods to address updated expectations.

A common characteristic of performance regulation is that it is implemented for a significant duration, such as five to ten years. Such a timeframe provides stability by enabling utility management to change systems and culture to manage new metrics. There is no rule, but the duration can be roughly equivalent to the horizon of confidence in key assumptions.

Some additional characteristics that generally make for successful PBR mechanisms are described below:

Clear Goal Setting: Clear policy goals help lead to clear metrics, incentives and outputs, which are the basic building blocks of a successful PBR mechanism;

Identification of Clear and Measurable Metrics: Metrics should be able to be clearly identified, with measurable data that provides objective information;

Establish Transparency at Each Step: Transparency at each step of the process, including the development of goals, metrics and incentives, can lead to utility, stakeholder, customer and public buy-in. This enhances the credibility of targets and reduces the risk of disagreements when rewards or penalties are applied.

Make Value to the Public Clear: The public values understanding what utility services they are paying for;

Align Benefits and Rewards: When rewards and penalties are applied closely in time with utility performance, the relationship of incentive to performance is easier to assess;

Learn from Experience: Modifying PBRs to address operational observations is a good management practice;

Compared to What? The simple question that looks for improvement in regulatory mechanisms along a continuous improvement pathway. This question is helpful in program design and examination of program improvements;

Simple Designs are Good: To minimize the risk of gaming, the best bulwark is to design a clear and well-defined incentive and metric(s). If the metric, as well as the corresponding data required to evaluate it, are difficult to measure, manipulation can be more difficult to detect;

Evaluation and Verification: Evaluation and verification of the outputs is an essential element of a successful PBR program.

U.S. Example: New York State

Perhaps the most ambitious use of PBR in the United States at present is in New York. A key part of its Reforming the Energy Vision package, the Public Service Commission is directing that each of the state's six investor-owned utilities make proposals on metrics. Scorecard metrics will be tracked and reported for use and scrutiny by experts and the public. Earnings Adjustment Mechanisms are metrics that address broad policy areas identified by the commission in a policy order (known as the Track 2 order) and that can earn a financial reward. The commission put a ceiling of 100 basis points over the normally allowed return on equity that can be applied to EAMs. The proposals are embedded in utility rate cases.

Source: The NY Track 2 was issued as part of PSC Case 14-M-0101 on May 19, 2016 and is titled "Order Adopting A Ratemaking and Utility Revenue Model Policy Framework." It is available for download on the PSC website: http://www.dps.ny.gov/.

1.3. Michigan background

1.3.1. Relevant legislation and regulatory authority

Traditional utility regulation is still the dominant model for Michigan's electric utilities. However, the state has implemented elements of performance regulation in recent years with the introduction of its renewable energy standard (RES) and Energy Optimization (EO) program. Adopted as a part Michigan's energy policy overhaul in 2008, the RES and EO program— established by Public Act 295—created compliance incentives for utilities.

The state's EO program, PA 295, gave the Commission the ability to approve financial incentives for rate-regulated utilities when they exceed energy savings targets for a given year (MCL 460.10 (75)). According to the Commission's 2014 Report on the Implementation of PA 295 Utility Energy Optimization Programs these incentives, "address some of the barriers EO programs have been facing in terms of lost revenue from declining sales" (MPSC November 2014). As outlined by PA 295, the financial incentive cannot exceed 15 percent of the providers' actual annual EO program spending or 25 percent of the customers net cost reductions as a result of the energy optimization plan, whichever is less (MCL 460.10 (75)).

1.3.2. 2017 energy legislation

SB 437 (S-7), enacted in 2017, makes substantial revisions to Michigan's energy regulatory regime. Among its provisions, SB 437:

- specifies that the Commission shall submit a report to the Legislation on performance-based regulation,
- specifies ratemaking time frames,
- stipulates that rates shall match cost-of-service,
- sets a goal that 35 percent of electricity in 2025 from either energy efficiency or renewable energy,
- sets a renewable portfolio standard of 15 percent by 2021 with an interim standard of 12.5 percent by 2019, and
- allows regulated utilities to provide on-bill financing of residential energy improvements with the repayment obligation running with the meter rather than the customer or property owner.

1.3.3. Utility composition and ownership structure

An understanding of the institutional arrangements, and the corresponding incentives or disincentives that have evolved over time, is critical to being able to successfully build a PBR scheme that can influence institutional behavior to achieve different outcomes. Utility managers respond to institutional incentives, opportunities for recognition, advancement and compensation in similar ways regardless of the ownership structure.

2. United Kingdom's Revenues = Incentives + Innovation + Outputs (RIIO): An Example of a Well-Functioning PBR

2.1. Basics and history

RIIO, put in place in 2013, was intended to begin a transition away from the traditional approach of simply rewarding investment in networks (sometimes called the "predict and provide mentality") under the prior cost cap regime to an outcome-based approach—a shift from inputs to outputs. The main goal of RIIO is the 'timely delivery of a sustainable energy sector at a lower cost to consumers than would be the case under the existing regimes'.[2] RIIO is a framework which retains strong cost control incentives while attempting to focus on long-term performance, outputs, and outcomes, with less focus on *ex-post* review of investment costs.

2.2. Structural elements

RIIO separates goals into 1-year and 8-year outputs. For each price control regime (gas, electricity distribution, electricity transmission) the regulatory authority (Ofgem) defines deliverables (measures of success) and units for measurement where applicable (metrics). Not all outputs are associated with incentives - this is to avoid unintended consequences (e.g. misreporting of incidents), and because some outputs are governed by other government agencies and are thus outside the control of the utility.

The UK regulators changed their price control mechanism to remove any bias that may normally exist between capital expenses (CAPEX) and operational expenses (OPEX) that would tend to lead utilities to prefer CAPEX. This approach has been referred to as "TOTEX" (total expenditures).[3] This means there is an incentive to deliver outputs rather than simply building new infrastructure. There was also an associated move from the previous five-year price control term to eight years as a reflection of the long-term nature of the investments necessary for a low-carbon transition, discussed further below.

2.3. Some RIIO lessons learned

2.3.1. Finding the right PBR timeframe

There is a tradeoff between setting PBR mechanisms to work over a certain number of years unchanged, to allow for the benefits of certainty to influence utility investments and operations,

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[2] Ofgem (2010): RIIO: A new way to regulate energy networks. Factsheet. Retrieved from: https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf

[3] The move to a total expenditure, or TOTEX, regime was first suggested by Ofgem in March 2008 when the energy regulator launched its RPI-X@20 review. From this comprehensive review of the previous regulatory regime, which had endured since privatization in 1989, emerged the RIIO (Revenue= Incentives+Innovation+Outputs) model.

and the need to recalibrate performance criteria and metrics - and perhaps reassess goals over time. The UK regulators realized five years was too short a period and moved to eight year periods under RIIO.

For more targeted PBR mechanisms, such as the earning adjustment mechanisms (EAMs) being implemented in New York, one of the key considerations a regulator must balance is the hands-off period over which the incentive should do its work to influence utility behavior (to assess its success) and the need to recalibrate if the mechanism is not working as intended.

2.3.2. Dealing with outcomes partially outside of the utility's control

Because some outcomes are influenced by the utility, yet also depend on influences outside of utility control, utilities may be reluctant to accept a pure outcome-based target or metric. One method to address this concern is to consider a rolling multi-year average rather than a pure annual target or annual metric. RIIO has a rolling average target for reliability purposes. Specifically, an unplanned outage target is set based on either the minimum of a utility's 2014/15 outage target or utility's own four year moving average.[4] This is an example of an approach that regulators might employ to implement targets or metrics where utility performance may be subject to appreciable uncertainty.

2.3.3. Focus on transparency of performance

In 2015, the House of Commons' Energy and Climate Change Committee reviewed concerns that a lack of information makes it more complex to assess whether or not the price controls are providing value for money, and recommended that 'a standard form of reporting' be explored. Following the recommendation by the Committee there were calls from consumer organizations for improved reporting by the network companies on the performance against the outputs defined by RIIO.[5] Since then, a reporting template has been developed by Ofgem which more effectively collects the necessary data. The results of this exercise are also communicated more transparently.[6]

2.4. Innovative approaches employed by RIIO

2.4.1. Utility benchmarking and scorecards

RIIO has a notable innovation: utility benchmarking and scorecards identify utilities that excel and

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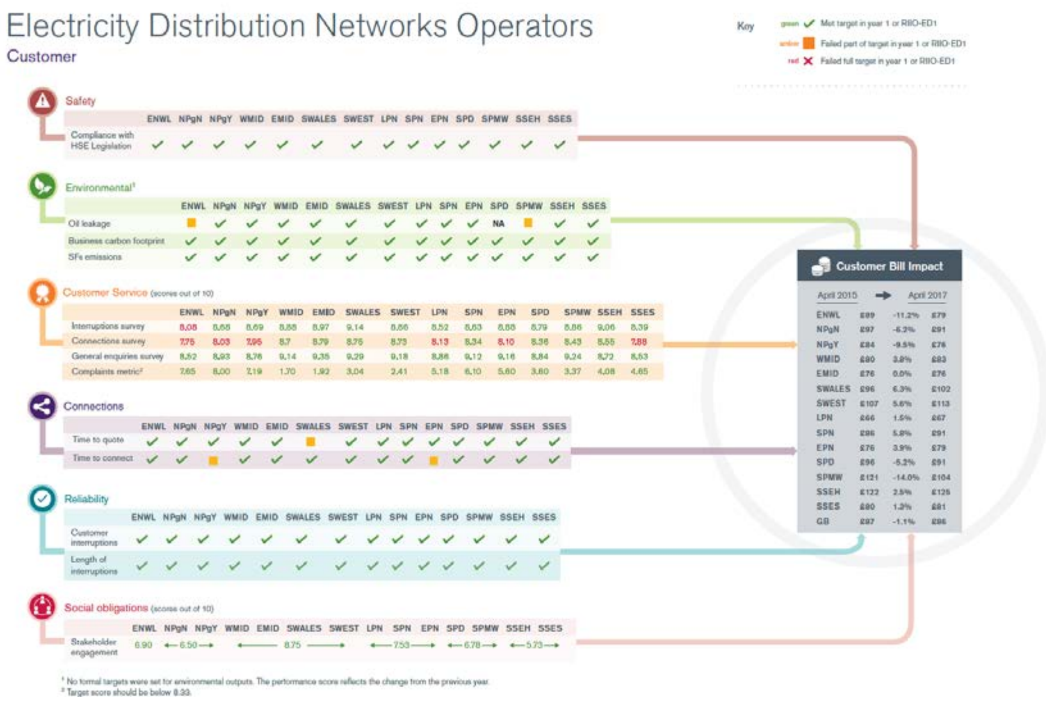
[4] Ofgem (2012). Quality of Service Presentation. Reliability and Safety Working Group. Retrieved from: https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/rswg_17_may_slides_qos_0.pdf

[5] Citizens Action. (2015). Beginning to see the light Why we need greater transparency in the RIIO model of energy network regulation, and how to deliver it. Retrieved from: https://www.citizensadvice.org.uk/about-us/policy/policy-research-topics/energy-policy-research-and-consultation-responses/energy-policy-research/beginning-to-see-the-light/. See also, House of Commons Energy and Climate Change Committee. (2015) Energy network costs: transparent and fair? - Sixth Report of Session 2014-15. Retrieved from: https://www.publications.parliament.uk/pa/cm201415/cmselect/cmenergy/386/386.pdf, p.19.

[6] Ofgem. (2016). Regulatory Reporting Pack. Retrieved from: https://www.ofgem.gov.uk/system/files/docs/2016/06/cando_rrp_template_version3.0_decision_2015_16_for_publishing.xlsx

lag. Applying benchmarking relies on a conclusion that utilities in a similar price control regime (distribution companies, for example) are similar enough that their outputs can be compared. Ofgem publishes annual reports on the performance of all network companies including tables that compare performances output areas. A color code is used to indicate the level of success achieved in the last year or forecast to be achieved over the upcoming 8-year period.

Figure 1: Example of RIIO Outputs



2.4.2. PBR for customer empowerment

PBR can improve utility focus on customer satisfaction and can also actively promote customer empowerment. Customer satisfaction has increased significantly under RIIO. This increase in satisfaction appears to some extent to be related to the published rankings of utility performance. Customers are able to see the satisfaction rankings, and based on these rankings or their own personal experience, will switch suppliers.[7]

[7] The Guardian. (2017). Energy bills: are UK customers finally starting to switch supplier? Retrieved from: https://www.theguardian.com/money/2017/feb/27/energy-bills-more-uk-customers-are-moving-supplier-figures-show.

3. Cost Cap Regulation

3.1. Basics

Cost cap regulation is a form of PBR that is explicit in allowing utilities to earn higher revenue if they become more efficient.[8] Cost cap regulation allows utilities to retain all or some portion of cost savings resulting from efficiency gains, so it provides a strong incentive to reduce costs.

In cost cap regulation, the regulator sets a limit on capital and operations and maintenance costs, and applies an escalator (based on the rate of inflation and expected productivity improvements). This produces a transparent, multi-year cap on costs. Without any capital cost tracker, it is likely that capital investments made during the period will only be those that lead to reductions in operations and maintenance costs greater than the capital costs. Savings would accrue to the utility until the next rate case.

As with all PBR mechanisms, it is important to think through potential consequences of the incentives that utilities are being given and to evaluate the mechanism over time to make sure that it is achieving the goals it has set out to achieve. Some of those considerations are discussed below. Things for regulators to watch are: reliability, service quality, and whether the utility is investing properly in its system and operations. It is important to set a “floor” for these areas, so that in its efforts to keep costs down, the utility doesn’t endanger reliability, service quality and system investment.

3.2. Key considerations

Ensuring utilities maintain reliability: To reduce expenses and increase retained earnings, a utility may fail to undertake necessary tree-trimming expense, which will quite directly lead to more severe storm outages from ice, snow and wind related line outages. A cost-cap mechanism can help address this by incorporating metrics to maintain or improve the level of reliability based on targets and metrics such as outage duration and frequency.

Ensuring utilities maintain service quality: A cost-cap mechanism can help ensure customer service quality by incorporating customer service PBR or PMI targets and metrics to reduce an incentive to cut back on customer services. Typical customer service targets include time to respond to service requests, hookup requests, time on hold on customer service lines, and numbers of customer complaints filed with the Commission.

[8] Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retreived from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 35.

Ensuring utilities continue to invest properly in their system*:* A capital cost tracker that ensures the utility will recover reasonable capital expenses can help alleviate the incentive to keep costs down. However, there are challenges with creating those trackers. If major capital expenditures are recovered through a fully reconciling cost tracker, utilities have little incentive to ensure that those costs are planned and managed as efficiently as possible. In such a case, it may be important to design a major capital cost tracker so as to provide such incentives, for example by establishing a mechanism that requires the utility to absorb a significant portion of any cost overruns.

If major capital expenditures are not recovered through a cost tracker, it can become much more challenging to establish a cost (or revenue) cap and a productivity index that provides cost control incentives while allowing the utility to adequately recover capital costs and protect consumers.

Absent a capital cost tracker approach, determining the appropriate escalation factor to apply in cost-cap regulation poses challenges. Among others, (a) there may be few comparable peer utilities for comparison purposes; (b) a utilities need to replace aging infrastructure is hard to assess without thorough review; (c) utilities (or the industry) are in a period of rapid transition, in terms of markets, technologies, or operations and for that reason historical costs and practices may not be a good indication of future costs and practices. A robust stakeholder discussion of the appropriate level of investment in the utility system can help to gain consensus on the utilities' capital spending plans. Including mechanisms to protect consumers against significant cost overruns may be advisable.

One Approach to Capital Costs:
the Rhode Island ISR Process

Electric and gas utilities in Rhode Island are required to submit an Infrastructure, Safety and Reliability spending plan annually to the PUC. The "ISR" is designed to reconcile costs for certain anticipated capital investments and other spending pursuant to an annual pre-approved budget for certain designated categories relating to enhancing the safety and reliability of the distribution system. The utility reviews the "ISR" with the Division of Public Utilities and Carriers (DPUC) prior to submission. It is also an opportunity to potentially develop stakeholder consensus regarding the utilities' needed investments.

The "ISR" addresses spending for utility infrastructure, repairing failed or damaged equipment, load growth/migration, sustaining system viability, continuing a level of feeder hardening and cutout replacement, and operating a cost-effective vegetation management program.

The "ISR" is intended to achieve safety and reliability goals through a cost-effective, comprehensive spending plan. In order to inform the selection of projects proposed for the "ISR," the utility performs distribution planning, which forecasts loads, identifies distribution system needs, and proposed infrastructure or non-wires alternative solutions.

More info: FINAL SIRI Vision Document, January 2016 retrieved July 9, 2017 at http://www.energy.ri.gov/siri/

While there are difficulties to be managed, the returns for cost-effective regulation are potentially large for Michigan ratepayers. There is strong evidence from other jurisdictions that electrical distribution company productivity can increase when operating under a multi-year cost cap plan.[9]

[9] Mark N. Lowry, Performance-Based Regulation: Can "The Other PBR" Make Sense for Wisconsin? Wisconsin Retreat on Utility Business Models of the Future, March 29, 2016, slide 23 (compare productivity of Central Maine Power to the Northeastern U.S. and Mid-Atlantic

4. PBR and PIMs for Energy Efficiency

4.1. Basics

Energy efficiency is a common focus of performance incentives in the United States today and has been since the early 1990s. Energy efficiency PIMs can help overcome the conflict in traditional utility regulation between cost-recovery guaranteed for capital expenditure (the incentive to build more) and energy efficiency cost recovery structures (the inventive to save more energy). They can also be designed to help overcome utility resistance to reduce sales and align utility incentives with energy efficiency goals.

Numerous U.S. jurisdictions have used PBR to motivate adoption of energy efficiency goals and satisfaction of targets and metrics. At least 26 U.S. states have used performance incentives to encourage energy efficiency deployments. This experience demonstrates that PIMs can help to improve utility energy efficiency program performance markedly. Utilities with operations in multiple states substantially improved efficiency markedly in states offering incentives.[10]

There are 4 basic types of PIMs for energy efficiency:

- *Shared net benefit incentives*. The utility can earn a portion of the net benefits of the energy efficiency programs (12 states);
- *Energy savings-based incentives*. Incentives are determined for achieving or exceeding energy savings goals, either in terms of energy (kilowatt-hours), capacity (kilowatts), or both. (6 states)*;*
- *Multifactor incentives*. The calculation of incentives includes multiple metrics, either designed to promote specific efficiency initiatives that might otherwise be overlooked (e.g., contractor training courses) or to achieve specific public policy goals. (5 states plus the District of Columbia);
- *Rate of return incentives*. Utilities are allowed to earn a rate of return on their energy efficiency spending, in order to make the financial incentives for efficiency investments comparable to those for supply-side investments. (1 state)[11]

To be as effective as possible, performance incentives for energy efficiency should be paired with multi-year rate plans and some mechanism to allow utilities to earn revenue even with lower sales

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Regions productivity 1993-2011); M. Lowry, T. Woolf, L. Schwartz, Performance-Based Regulation in a High Distributed Energy Resources Future, Future Electric Utility Regulation, Lawrence Berkeley National Lab, Rept. No. 3, Jan. 2016.

[10] EE incentives were found to motivate utilities to improve EE performance targets. Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M., and York, D. (2015) Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency. ACEEE. Retrieved from http://aceee.org/research-report/u1504

[11] State and Local Energy Efficiency Action Network (2016). SEE Action Guide for States: Energy Efficiency as a LeastCost Strategy to Reduce Greenhouse Gases and Air Pollution and Meet Energy Needs in the Power Sector. Prepared by: Lisa Schwartz, Greg Leventis, Steven R. Schiller, and Emily Martin Fadrhonc of Lawrence Berkeley National Laboratory, with assistance by John Shenot, Ken Colburn and Chris James of the Regulatory Assistance Project and Johanna Zetterberg and Molly Roy of U.S. Department of Energy. Retrieved from: . See pages 12-13 citing numerous sources.

(e.g. revenue decoupling). This helps to address the throughput incentive, an attribute of traditional regulation that causes utility net income to be dependent on utility sales. A multi-year approach also opens energy efficiency program administrators to strategies that take time to develop.

4.2. Key considerations

Experience with PBR and PIMs for energy efficiency has highlighted a few things to consider when designing and implementing these mechanisms.

Ensuring utility incentives are working together*:* Energy efficiency PIMs have contributed to utility management buy-in and can influence efficiency program planning.[12] Utility management may be willing to dedicate more resources and employee time to planning and deployment of efficiency programming if success of that programming improves utility revenues. Experience has shown that PBR for efficiency operates well when implemented in concert with a lost revenue recovery mechanism (such as revenue decoupling) which removes the utility disincentive to reduce sales

Evaluating and communicating the effectiveness of PIMs and PBR*:* Regulators in multiple jurisdictions have assessed the effectiveness and cancelled programs that are not working. It is important to communicate the value of the intended outcome—the value of actual utility outputs that produce beneficial customer outcomes—and to link the value of the incentive to that outcome, so that when the outcome is achieved the value of the incentive is not viewed as excessive. As an example, Washington State's Puget Sound Power and Light earned high rewards in an energy efficiency program for exceeding cost targets for a single measure (high-efficiency showerheads) while ignoring others. This was perceived by the Washington regulators as overcompensation and manipulation of the reward metrics and the program was cancelled.[13] Programs can be cancelled or modified when incentives are excessive or intended outcomes are not achieved. This example also illustrates a choice for the PBR designer: whether to only award financial incentives if the utility achieves satisfactory results for ALL metrics.

Clearly evaluating and measuring savings when benefits are shared*:* Under shared net benefit incentives, the utility shares along with ratepayers in the benefits associated with the metric achieved. This can mean sharing in financial benefits between the utility and ratepayers. In the context of EE programs, a "shared savings" approach shares the EE savings between ratepayers and the utility. This approach relies upon accurate benefit calculations from Evaluation, Measurement and Verification (EM&V). A clear EM&V plan based on objective metrics is advisable. With a shared benefits approach, care needs to be taken the ensure cost control incentives are maintained to excessive costs are not incurred to produce benefits that are then "shared".[14]

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[12] M. Lowry, T. Woolf, L. Schwartz, Performance-Based Regulation in a High Distributed Energy Resources Future, Future Electric Utility Regulation, Lawrence Berkeley National Lab, Rept. No. 3, Jan. 2016.

[13] SEE Action Report at 53.

14 For some examples of advanced methods to control utility costs in a PBR regime, see Regulatory Assistance Project, 2000, p. 4.

5. Innovative Uses for PBR

PBR is a flexible regulatory tool that allows for the pursuit of a broad spectrum of utility performance goals, outputs and outcomes. Jurisdictions have used PBR for a number of innovative purposes, a selection of which are briefly mentioned below. Some of these ideas may fit for Michigan goals and objectives and can emerge from stakeholder advice and collaboration.

5.1. Incentives to promote DER Deployment

A PBR regime can promote DER deployment, for example by encouraging utility, consumer and solar DG developer cooperation in effective interconnection evaluations. In New York's Reforming the Energy Vision (REV) process, an earnings adjustment mechanism is under development specifically for DER deployments.

5.2. Incentives for sharing utility data

Customers and providers can use energy cost and usage data to make more efficient decisions to reduce their costs and increase the value of their energy systems. Utility performance incentives and corresponding metrics that motivate utilities to provide data to customers, and with customer consent to third-party energy technology companies, is critical to facilitating a competitive energy services space.

5.3. RE performance metrics

Regulators can require utilities to report and track performance on a variety of metrics to demonstrate success with renewable energy deployment. For example, Hawaii is in the process of whether and how to have its utilities keep track of system-wide renewable energy (excluding customer-sited generation), compliance with the RPS, total renewable (including customer-sited generation), and the number of participants in the net-energy metering program.

5.4. Locational metrics for reliability or high-cost areas of DER deployment

By concentrating DERs in a high cost utility area (i.e. an area where short-term marginal costs of system improvements are high), DER investments may help to defer or avoid grid upgrades. Sharing of locational energy data can be structured in a PBR system to designate high-cost utility areas as high value for DER development. The structure of the PBR system would incent the utility to provide customers and third-party developers with data on where DERs are most desirable.

5.5. GHG emission performance

Greenhouse gas emissions reduction is an area ripe for PBR. The guiding goals, directional incentives, performance criteria, and metrics are readily able to be calculated and tracked. A well-designed PBR scheme could allow utilities to select the most cost-effective means of achieving GHG reductions and reward utilities for doing so.

5.6. EV deployment and charging infrastructure rollout performance

Special EV rates are being adopted or piloted in some jurisdictions. Because these rates are new and little understood by ratepayers, there is a need for better marketing of the availability and design of such rates to various customer classes. This is a potential area for PBR application, focusing on consumer education around home charging rates.

5.7. Operational incentives: Improved power plant performance

PBR for generator performance can be useful if there are certain behaviors or attributes of generators that a regulator wants to incentivize. Metrics can include equivalent availability factor (EAF), equivalent forced outage rate demand (EFORd), and Equivalent Forced Outage Factor (EFOF).

5.8. Operational incentives: Improved interconnection request response times

Performance metrics can be developed to track the time it takes for distributed energy resources to connect to the grid. Another option is to develop a metric associated with an interconnection survey process and reward utilities when they receive high marks for customer satisfaction. The New York REV process is looking at both options to help improve interconnection times for DERs.

5.9. Operational incentives: Differing approaches to achieving system efficiency

Operational metrics can focus on achieving system efficiencies, such as load factor improvement and peak reduction. Metrics might be focused on reducing system losses, including theft and operational efficiency.

5.10. Operational metrics: Reliability

The optimal reliability level is where marginal utility costs to achieve a level of reliability is equal to marginal customer reliability benefits, which can be determined using customer surveys. Motivating utilities with positive and negative incentives around reliability levels is a particularly innovative approach to implementing reliability goals. Another approach is to offer utilities increased certainty around capital investments that affect reliability, such as pole reinforcements, undergrounding targeted lines, and vegetation management.

5.11. Modified fuel adjustment clauses to address higher ramping rates for integration of renewables

Jurisdictions with fuel adjustments clauses found a disincentive to use of fuel efficiently (if ratepayers pay for all fuel costs as a pass-through). So some jurisdictions adopted PBR-like incentives for heat-rate targets based on the fossil-fleet characteristics of the utility. Fast forward to now, an era when fossil units are expected to balance and provide ancillary services on systems with intermittent resources such as wind and solar power. Higher ramping can make those heat rate targets harder to meet thus motivating further adjustments to the fuel rate adjustment clauses to allow for higher ramping rates operations without an effective penalty for such operations.

5.12. PBR approaches to promote customer empowerment

PBR can improve utility focus on customer satisfaction and can also actively promote customer empowerment. Customer empowerment is defined here as the ability of customers to provide feedback on utility service, demand-side energy options, and the ability to see publicly reported performance data on their utility. Metrics can include the number of customer complaints and response times to resolve complaints, response time to service requests, and a survey of customer satisfaction.

5.13. PBR approaches to support competition

Because some services and products provided by energy service companies - such as distributed generation, smart energy management systems, and energy storage - can compete directly with utility offerings and reduce the need for utility services, utilities may perceive a competitive risk from these companies. To address anti-competitive utility behavior, PBR metrics can encourage utility cooperation to deliver required services, such as the number of DERs on the system.

5.14. Compliance with codes of conduct in support of competition

Codes of conduct govern how utilities (and their affiliates) interact with companies that compete with them. A PBR incentive for compliance with codes of conduct would be closely associated in concept with support for competitive DER markets, but be distinct because it would focus on corporate separation and compliance with codes of conduct. The PBR metrics could track the number of complaints of violations made to the utility.

5.15. Peak load reduction enabled by demand response

Peak load reduction is a key cost-avoidance opportunity for systems with growing generation, transmission and distribution peaks. If peak load reduction is a policy goal that the jurisdiction seeks to implement, a PBR mechanism can rewards the utility for reducing peak load.

5.16. Customers enrolled in time-varying rates

Because system costs vary considerably by time of day, and by season for both generating and delivering electricity, customers will make more efficient decisions for themselves and the system if they see the relative scarcity or abundance of electricity service reflected in their price. However, customers can only adjust their use appropriately if the price accurately reflects the system costs during peak hours. A PBR metric tracking the number of customers enrolled in time-of-use rates can incentivize utilities to get their customers signed up.

5.17. PBR for smart meter deployment

PBR for smart meters can include an incentive for the number of meters that are installed and able to communicate, and providing data as required, compared to a forecasted or desired deployment timetable. If the forecasted deployment percentages are not achieved, a penalty can be generated.

6. Appendix: Innovative Uses for PBR—More Detail

This appendix provides more detail on the innovative approaches summarized in Section 5. The material excerpted here also appears in a paper from the National Renewable Energy Laboratory.[15]

This Appendix offers innovative approaches to reach varied public policy goals. It is intended to provide decision makers with ideas, some of which are in existence, some of which are theoretical, on how to reach specific public policy goals with a PBR mechanism.

- Key Point #1: PBR is an extremely flexible regulatory tool that allows regulators, utilities and stakeholders to pursue desired goals, outputs and outcomes for electric utility performance
- Key Point #2: PBR can pursue goals across an immense spectrum of utility performance to provide appropriate incentives for utilities to change their performance in specified areas of interest or concern for regulators, policymakers and utility stakeholders.

As illustrated in the sections above, performance-based regulation has evolved greatly since its inception over two decades ago. PBR is now being used in a variety of jurisdictions worldwide in innovative and wide-ranging ways. A selection of innovative PBRs and PIMs is examined below by topic area. This is not an exhaustive list, but should provide an overview of the different ways PBR is being applied to different aspects of electric utility regulation.

6.1. Incentives to promote distributed energy resource deployment

Performance-based regulatory frameworks are ripe with opportunity to help address the negative incentives utilities face – oftentimes inherent to traditional cost-of-service regulation constructs – to achieving efficient levels of DER deployment.

6.1.0. Solar distributed generation

A guiding goal of a PBR regime can be to encouraging solar DG or to encourage utility, consumer and solar DG developer cooperation in effective interconnection evaluations. In 2013, Hawaii adopted utility performance metrics for DER deployment. These included measurement of the number of Net Energy Metering (NEM)[16] program participants and installed solar DG capacity, as well as enrollment numbers for utility demand response and storage programs. These metrics are to

[15] Littell, D., et al. “Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation.” National Renewable Energy Laboratory Technical Report NREL/TP-6A50-68512, September 2017. Retrieved from https://www.nrel.gov/docs/fy17osti/68512.pdf

[16] Hawaii has since terminated solar NEM.

be posted on the utilities' websites to facilitate access on DER levels for utility customers.[17] There are no incentives associated with these metrics with implementionation occurring as Hawaiian solar DG growth increased sharply.

To address the customer and stakeholder's desire for information on DER deployments and application processing, Massachusetts used "dashboards."[18] Dashboards are computerized summaries of key data on a specific topics such solar DG deployment presented on a web-based portal. While not an incentive mechanism per se, dashboards can set up very effective communication methods with customers, the public and DER developers. Moreover, presentation of dashboard data in graphic form involves presentation of DER information (number of units, capacity, energy produced, geography) that comprise a number of metrics that set public reporting obligations similar to a specific performance criteria. Dashboard and energy portals transform a set of goals or targets into the reporting, tracking and presentation of information that provides the public with an understanding of which metrics are important to assess utility and power system operations.

6.1.1. Distributed energy resource deployment and provider satisfaction

Rather than create a baseline for DER deployment or simply track DER interconnection requests, the NY PSC focuses its PBR for DER on a survey of DER providers. The survey is still under development in a stakeholder process with the NY PSC. The NY PSC recognized the baseline difficulties for DER and the reality that a simple interconnection DER performance metric can be difficult to implement as well. For this reason, the NY PSC opted to create a sophisticated survey of DER providers to assess how well utilities are working with DER developers on interconnections and identifying targeted grid system needs where DER may have high value to meet grid needs for reduced load.

Earlier, in a precursor to REV, the NY PSC approved incentives to reward use of a mixture of DERs for the Brooklyn Queens Demand Management (BQDM) program. The BQDM was proposed by Consolidated Edison to address load growth in the Brooklyn and Queens boroughs of New York City and to address concerns about the cost of grid side investment solutions. The BQDM project has avoided constructing a new substation, a switch station and new sub-transmission feeders at a cost of roughly $1 billion. Instead a portfolio of DERs were implemented to reduce load and peak below levels required to trigger the new transmission and distribution upgrades. The DERs were obtained through a utility-administered request for proposal process to identify and allow the utility to procure the lowest-cost distributed energy projects with regulatory oversight.[19]

As part of REV, the NY PSC has a separate EAM specifically for DER deployments. A DER

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[17] M. Whited, 2015, p. 89, citing Hawaii Public Utilities Commission ("HI PUC"). 2014. Decision and Order 31908 in Docket 2013-0141: Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[18] M. Whited et al, 2015, p. 32.

[19] NY PSC. 2012. Order Establishing Utility Financial Incentives. Case 07-M-0548. Retrieved from: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/06F2FEE55575BD8A852576E4006F9AF7?OpenDocument

Utilization EAM encourages New York's largest utility, Con Edison, to expand use of DERs, to reduce customer reliance on grid-supplied electricity and for beneficial electrification.[20] The DERs falling under this EAM initially are: solar photovoltaic systems, combined heat and power (CHP), fuel cells, battery storage, demand response, thermal storage, heat pumps, and EV charging. DERs will be measured in terms of the annualized MWh produced, consumed, discharged, or reduced from incremental (new to the Rate Year) resources. Because not all DERs are individually metered or measured, MWh produced or consumed by incremental DERs will be counted through default factors for DER energy usage and consumption.

Non-Wires Alternative Requirement in California

In December of 2016 the CPUC approved a mechanism that seeks to induce utilities to consider non-wires solutions to distribution system reliability needs. Reliability needs on the distribution system may be precipitated by load growth or by the growth of certain DERs, and traditional distribution investments undertaken to address these needs include measures like reconductoring circuits to higher voltages, replacing transformers, or even expanding a local substation. However, the reliability needs may also be addressed through adding local reliability services that do not require "traditional" wires investment solutions. "Non-wires" services that may address an emerging need include increased distribution capacity services, voltage support services, back-tie reliability services and resiliency services.* DERs that can meet some or all of these needs include EE, DR, Storage, PVDG and other DG resources, and a portfolio of these DERs is likely to be constituted to meet the specified needs. Each utility is required to identify a significant upcoming distribution system investment need and to solicit proposals to meet the need with portfolios of distributed resources. Each utility is required to specify the reliability services that are needed to address the need, and to issue a request for proposals to procure the needs. The submitted proposals are to be evaluated based on a technology-neutral least cost, best fit basis. If the most cost effective, best value proposal is superior to the distribution wires investment solution, then the utility will be required to enter into a contract with the winner. A pro forma contract will be developed over time to make the non-wires contracting process more routine. The utility is entitled to recover all costs of administering the non-wires solicitation and, as compensation for an effective solicitation, the utility will be entitled to earn 4 percent on the annual contract cost of the contracted non-wires alternative.

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* CPUC. (2016). Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot. Rulemaking 14-10-003. Page 8.

New York is also developing a survey of DER providers to support PBR mechanism to incentivize timely interconnection of DERs. Utility performance will be assessed based on surveys of DER providers and satisfaction of Standardized Interconnection Requirements (SIR)[21] as a threshold

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[20] Dennis, K., Colburn, K., Lazar, J. (2016, August). Environmentally Beneficial Electrification: The dawn of "emissions efficiency." Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/environmentally-beneficial-electrification-dawn-emissions-efficiency/

[21] Standardized Interconnection Requirements (SIR) address technical guidelines for interconnection and application procedures, with two separate sets of interconnection procedures: an expedited process for systems up to 50 kW, and a basic process for systems above 50 kw and up to 5 MW. Both processes include interconnection process timelines that the utility must meet, responsibility assignments for interconnection costs, and procedures for dispute resolution, as well as many technical requirements for the systems. Utilities are required to maintain a web-based system that provides information on the status of interconnection requests. See: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/SIR%20Final%2

condition. Favorable survey outcomes will result in a positive earning adjustment under New York's REV (this will be described in more detail below). For projects over 50 kW, the EAM will have the following components: 1) A threshold condition based on adherence to the timeliness requirements established in the Standardized Interconnection Requirements (SIR); and 2) A positive adjustment based on an evaluation of application quality and the satisfaction of applicants with the process, as measured by: A) a survey of applicants to assess overall satisfaction, and B) a periodic and selective third party audit of failed applications to assess accuracy, fairness, and key drivers of failure in order to support continual process improvement. The Commission will also consider on a case-by-case basis negative earning adjustments for failure to meet established standards.

The use of surveys by New York to assess utility performance on DER deployment goals is particularly innovative. There are at least two problems with simplying measuring interconnection times, application or quantiy, which New York may be able to avoid by using surveys. The first problem is that simply measuring interconnection times and applications processed can be easily gamed by utilities quickly denying interconnection requests. Measuring interconnection time and applications processed does not measure whether meritorious applications are approved and applications with technical difficulties are denied – and it is very difficult to objectively measure the merits of approvals and denials without detailed knowledge of each distribution circuit. The second problem avoided is that measuring DER quantity in numbers or DER energy generated/avoided may measure outputs or outcomes that are more dependent on exogenous factors than how the utility handles interconnection requests. These exogenous factors include local market dynamics and third-party energy service company activity which influence the quantity of DER installed but are largely exogenous to utility operations. Refinement and implementation of these DER provider surveys will occur in upcoming years in New York.

6.2. Incentives for sharing utility data

Utilizing real time energy cost and usage data systems is critical to optimize the efficiency of energy production and delivery.[22] Sharing this data can foster system optimization by facilitating access to utility and customer data that allows for more efficient decisions. Sharing of specific customer data usually requires customer consent; thus data usage systems must also facilitate customer consent. Alternatively, utilities can share anonymized data as part of an evolving platform function.[23] If

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[22] Jim Lazar, Beyond Decoupling, Creating an Effective Power Sector Framework for Clean Energy Objectives: Aligning Utility Business Models with Clean Energy Policies, RAP, Dec. 31, 2011 citing Peter Fox-Penner, Smart Power: Climate Change, the Smart Grid and the Future of Electric Utilities, 2010, Island Press; Valochi, et al. Switching perspectives: Creating new business models for a changing world of energy, IBM Inst. for Business Value, 2010.

[23] The NY PSC noted the evolving role of the utility and the potential platform services utilities could offer. In the Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, the PSC noted that "utilities will have four ways of achieving earnings: traditional cost-of-service earnings; earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; earnings from market-facing platform activities; and transitional outcome-based performance measures." This recognizes the fact that "the traditional provider's role has evolved to a platform service that enables a multi-sided market in which buyers and sellers interact. The platform [will collect] a fee for this critical market-making service, while the bulk of the capital risk is undertaken by third parties." State of New York Public Service Commission. (2016, May 19). Case No. 14-M-0101. Order Adopting a Ratemaking and Utility Revenue Model Policy Framework.

energy cost and usage information becomes more transparent, customers and providers can use this information to make more efficient decisions to reduce their costs and increase the value of their energy systems for their specific needs.

To share data more freely, it is often necessary to address barriers that prevent DER providers from obtaining both utility and customer data. Third-party clean energy technology companies view the lack of a utility incentive to easily share utility and customer data (again with customer consent) as problematic, particularly since this data would provide opportunities for them to offer alternative solution sets to consumers, lower costs of customer acquisition, and to compete with utilities for certain services.[24] The need for utility performance incentives and corresponding metrics that will motivate utilities to provide data to third-party energy technology companies in order to compete in this space is critical to facilitating a competitive energy services space. NY REV has focused on addressing these issues by adopting a DER provider survey as part of its EAM. The NY REV DER survey is currently under development.

6.3. Incentives for water savings

There have been significant regulatory responses to water shortages in various jurisdictions. California faced a multi-year drought recently, but its concern with reducing water usage by power plants is long-standing based on desires to reduce ocean and coastal ecosystem impacts . As a result, the state adopted the mandatory retirement of once-through cooling facilities for all its generating plants and required dry cooling on some of its natural gas power generators. Nevada requires dry cooling on all new generation, but this is enforced at the water permitting level. None of these requirements is set up as a PBR mechanism but rather as traditional regulatory requirements, which is surprising given the power sector's significant use of cooling water.

To date, a PBR scheme to provide an incentive to conserve or avoid water usage has not been adopted. A PBR for water savings from a baseline year for cooling water usage can be easily envisioned based perhaps on overall water withdrawals, or simply consumptive uses accounting for evaporation, aquatic life impacts from withdrawals and thermal impacts on receiving water bodies. A second approach could apply a benchmark for water consumed (on a consumptive standard) per MWh of electricity generated or purchased, and be applied at the utility level or at the distribution utility level in restructured markets. Performance below the baseline or benchmark could be rewarded, and performance above those levels could be penalized. PBR constructs focused on water savings, while not common in the electricity sector, have been used in the water utility sector to encourage water conservation in areas with water shortages. Southern Nevada Water Authority, for example, has very aggressive pricing and lawn removal programs.

6.4. Renewable energy performance metrics

Hawaii adopted performance metrics for distributed renewable energy. The Hawaii guiding goals

[24] Elking, E. (2015). Knowledge is Power, How Improved Energy Data Access Can Bolster Clean Energy Technologies & Save Money. Center for Law, Energy & the Environment Publications. Berkley, CA. Retrieved from: http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1016&context=cleepubs

and directional incentives identified for refinement and further consideration include system renewable energy (excluding customer-sited generation), total renewable energy generated (including distributed generation), renewable energy curtailments and RPS compliance. These metrics are to be posted on the utilities' websites to facilitate customer access and private market decision making and planning.[25]

In March of 2015, Hawaii further ordered development of metrics, a website and review process for renewable metrics among others. The Hawaii Public Utilities Commission ordered the utilities to "regularly report, maintain, and promptly periodically update the [renewable energy] performance metrics," and to "participate in an iterative metrics and website development and review process."[26] This process would establish and post to a website metrics for:

- System Renewable Energy Metric (System RE Metric)
- Renewable Portfolio Standard Compliance
- Total Renewable Energy Metric (Total RE Metric)
- Number of NEM program participants and capacity of NEM program[27]

The development of these metrics will facilitate transparency with customers, the public, stakeholders and the public.

6.5. Locational metrics for reliability or high-cost areas DER deployment

For telecommunications systems, locational reliability is often measured by circuit. This is not done for electrical service but could easily be implemented with the advent of smart grid monitoring technologies. Circuit reliability, certain customer service measures (such as circuit specific SAIDI or SAIFI) or power quality could be measured with devices installed at substations, feeders and customer meters. Initially circuits could be selected with a history of service issues, or where high levels of DER penetration are changing circuit characteristics.

By concentrating DERs in a high cost utility area (i.e. an area where short-term marginal costs of system improvements are high, and DER investments may help to defer or avoid grid upgrades). Infrastructure and operation cost savings can offset utility revenue losses and make net savings available for a PBR shared savings to reward utilities for cost reductions and innovation.[28] This is perhaps most easily accomplished in vertically integrated utilities where savings from DERs in supply and utility plant accrue to the utility itself but also could be quite valuable to a distribution company.

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[25] M. Whited, 2015, p. 89, citing Hawaii Public Utilities Commission ("HI PUC"). 2014. Decision and Order 31908 in Docket 2013-0141: Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[26] Order No. 31098.

[27] *Id.*

[28] Regulatory Assistance Project, Performance-Based Regulation for Distribution Utilities, Dec. 2000, p. 40.

This model of sharing of location energy data can be structured in a PBR system to designate high-cost utility areas for DER development is high value. The structure of the PBR system would incent the utility to provide customers and third-party developers with data on where DERs are most desirable, i.e. have highest system value. As New York did with the BQDM discussed above, the utility with a PBR incentive could provide incentives such as direct payments to DER providers or customer, direct DER investment where legally authorized, or facilitate competitive procurements among DER providers with payments to DER vendors capped at the utility savings to direct DER development to these high-cost areas.[29] This is precisely how the NY PSC's BQDMP worked: the utility was allowed to recover the costs of DER assets acquired by it and also an additional ROE adder is successful in acquiring adequate demand-side reductions through its DER acquisition process. While this can be described as a shared savings system, implementation occurred through an ROE adder and allowed recovery of utility costs for direct utility procurement of DER assets. The measurable performance criteria and metrics were for specific load reductions to be achieved through DER procurements by the utility itself.

Utility savings can be calculated using the short-run marginal cost of distribution and electrical supply. So while NY's BQDMP incentive was an ROE adder, this structure resulted in shared savings. The shared savings consisted of ratepayers avoiding additional distribution costs and Con Edison receiving some of these savings in the form of a ROE adder. These total savings can be expressed in short run marginal avoided costs of major substantion upgrades. Again in theory, the price of a good or service should be equal to its short-run marginal costs under conditions of competition. The NY BQDMP demonstrated that a short-run marginal cost of avoided distribution system costs could indeed be the costs of acquiring a suite of DERs. Moreover, in efficient markets, the short-run marginal costs should equal the long-run marginal costs.[30] The NY BQDMP demonstrates that under conditions of low load growth, the marginal costs of additional DER infrastructure may indeed represent the short-run and long-run marginal system costs.

6.6. Greenhouse gas emissions performance

Greenhouse gas emissions reduction is an area ripe for PBR. The guiding goals, directional incentives, performance criteria, and metrics are readily able to be calculated and tracked. A well designed PBR scheme could allow utilities to select the most cost-effective means of achieving GHG reductions and reward utilities for doing so. In fact, an emissions standard has been put forward as a regulatory standard for states to consider during the Clean Power Plan discussions in the United States. This concept is transferable to a PBR.

At least one jurisdiction has adopted a metric for greenhouse gas emissions reductions in a settlement reached in Illinois in 2013 around cost-justification for advanced metering infrastructure (AMI). This Illinois settlement by parties interested in justifying the cost of AMI requires a performance metric to be developed by the utility Commonwealth Edison to track reductions in greenhouse gas emissions (as measured through load shifting, system peak reductions and reduced meter-reading truck rolls attributable to smart meters and associated time-of-use rate

[29] Regulatory Assistance Project, 2000, p. 41.

[30] Regulatory Assistance Project, 2000, p. 41, fn. 16.

modifications).[31] This Illinois settlement also includes metrics to calculate power plant marginal emission changes and changes in generator dispatch due to load shifting of smart meter customers compared to non-AMI customers on an hourly level. Other metrics are to be developed for GHGs to track plant closures that may occur from reductions in system peak, and reductions in fuel consumption from reduced meter reading vehicle rolls broken down by specific operating centers.[32] Reporting and development of these metrics may provide sufficient regulator and utility experience, which can then be refined and then used to build goals with incentives and performance criteria in the future. Indeed, developing experience with accurate performance criteria that can be used to set goals, and to measure those accurately is one of the prerequesites to successful PBR.

6.7. Electric vehicle deployment and charging infrastructure rollout performance

Retail EV rates are being adopted or piloted in some jurisdictions. Because these rates are new and little understood by ratepayers, there is a need for better marketing of the availability and design of such rates to various customer classes when they are implemented. This is an area of potential for PBR application, yet the design of an effective PBR system around EVs presents design dilemmas that jurisdictions grapple with: should the focus on educating consumers be about home charging rates or focus on building out public EV charging infrastructure and perhaps include attention to consumer protection for public charging sales? The public charging infrastructure is quite expensive and if allowed in rate base, utilities probably have adequate incentive to build that infrastructure. Rather, the utilization of high-cost charging infrastructure may become the primary concern but the use of charging stations is generally beyond both utility and regulator control. The number of EVs in use may influence use of charging stations, but that is certainly beyond utility and regulator control. For these reasons, focusing on education around home charging rates is more ripe for utility education and consumer interface. Indeed, modest utility support for home charging infrastructure support consumer adoption and load-growth of clean energy.

The multi-year rate plan, an early form of PBR, may provide an approach to incentivize utilities to market new EV rates to customers. Utilities under a multi-year rate plan may be able to retain or share in revenue growth from revenue of EV-based rates between rate cases. Multi-year rate plans would provide an incentive for utilities to market attractive EV rates to ratepayers for home EV charging because utilities would enjoy increased revenue. In this manner, growing consumer usage through home EV charging is entirely consistent with the multi-year rate case model developed in the U.S. In states with multi-year rate plans and where utilities have marketing flexibility, the multi-year rate plan approach has potential to become a powerful driver of EV charging usage and interest among utility customers.

For jurisdictions that have utilities preparing infrastructure for EV charging stations, the utilities work could be considered for PBR in the context of the jurisdiction's guiding goal. If the guiding

[31] M. Whited, 2015, p. 84, citing Commonwealth Edison. 2014. Smart Grid Advanced Metering Annual Implementation Progress Report. Commonwealth Edison Company.

[32] M. Whited, 2015, p. 86, citing Commonwealth Edison. 2014. Smart Grid Advanced Metering Annual Implementation Progress Report. Commonwealth Edison Company.

goal is to prepare infrastructure for charging station completion, then a measurable performance criteria might be utility make-ready work performed for EV charging station completion. National Grid has proposed such a performance criteria in Massachusetts which will be considered by the Massachusetts Commission. Under the terms of the proposed National Grid program, EV charging sites would be owned by independent vendors with National Grid providing assistance. The Program would include a performance incentive for Grid, with a maximum award representing 5.5 percent of the total program budget. The incentive would be awarded for each EV charging site developed and activated. The threshold for receiving the minimum award of $750,000 would be activation of 105 sites, or 75 percent of the program target. The maximum award of $1.2 million would be earned if 175 sites (125 percent of the program target) are activated. The petition is currently under consideration.[33]

6.8. Operational incentives: Improved power plant performance

There is history of California regulators developing system operational incentives when its utilities were vertically-integrated in the late 1980s and 1990s. During this period of time, nuclear plant costs were so expensive that nuclear plants faced the possibility of sitting idle because rates were not high enough to recover their fixed costs. As a result, in a 1998 settlement California regulators set rates for Diablo Canyon nuclear station based on an avoided cost calculation. This rate was above market rates, and was meant to allow the plant to operate and provide service to ratepayers. The rate was fixed, escalating only for inflation. The performance guiding goal was to achieve increased hours of generation. Under this settlement, this nuclear station was earning more than $0.12/kWh while the Western U.S. wholesale market prices dropped to roughly $0.03/kWh. Hindsight demonstrates that the avoided cost calculation did not predict the future price.

Learning from that error where ratepayers paid far above market rates for generation from a specific nuclear plant, California then set the avoided cost for replacement power payment for the Palo Verde nuclear station at the market-based cost of replacement power. The cost of replacement power was the cost for the California utility to charge to its ratepayers for power to serve the utility's load, in this case purchased from the Palo Verde nuclear station. Subsequently, the California energy crisis occurred in the summer of 2000, and the cost of replacement power increased ten-fold. The result was utility payments for nuclear power at much higher replacement power costs than were anticipated.[34] Both mechanisms were subsequently modified due to a perception that the utility was overcompensated for the cost of nuclear generation. Both of these California mechanisms were pricing mechanisms intended to incentivize acquisition of low-cost power through pricing of power purchases depending on formulas that did not anticipate future energy market price adequately. To the extent the pricing formulas were intended to incent purchases from these nuclear power plants, they succeed. However, to the extent the formulas were intended to save ratepayers any money, the pricing failed to incorporate mechanisms that ensured ratepayer savings would occur.

[33] National Grid filing in Massachusetts Department of Public Utilities, Docket 17-13, filed January 20, 2017.

[34] M. Whited et al, 2015, pp. 53, 63-69.

Moving forward two decades, in 2014, Hawaii adopted performance metrics for generator performance. These include equivalent availability factor (EAF), equivalent forced outage rate demand (EFORd), and Equivalent Forced Outage Factor (EFOF). These metrics were ordered to be posted on the utilities' websites to facilitate stakeholder and customer access.[35] As noted in Section 5.2 above, while reporting obligations for certain performance criteria or metrics is a weak form of PBR, it is PBR nonetheless. The requirement that utilities track, analyze and report specific information can affect utility behavior and may be precedent to establishing incentives.

Prior to 2014, Hawaii had an Energy Cost Adjustment Clause with a heat rate efficiency factor. This clause encouraged dispatch of the most efficient power plants with the lowest heat-rate, meaing the most thermal-energy generated per unit of fuel input. However, concerns were raised that the heat rate target would penalize utilities for integrating higher levels of renewables that might impose a higher ramping requirements and lower capacity factors for thermal power plants balancing renewable loads - which both would negatively impact thermal unit heat rates. To address this disincentive for renewable integration, a dead band of +/- 50 Btu/kWh sales was added to heat rate target.[36] A dead band is a zone of no adjustment around a specific performance criteria or metric; in this case the dead-band is expressed as a meteric around the allowed heat rate so the utility would not lose the benefits of the heat rate efficiency factor if ramping to accommodate renewable resources increased or decreased the heat rate within a range of 50 Btu/kWh. A dead-band thus provides a range where utility revenue is not affected by variation in the metric.

6.9. Operational incentives: Improved interconnection request response times

An Illinois Commission approved settlement in 2013 requires a performance metric be developed by Commonwealth Edison to track time to connect distributed energy resources to the grid.[37] These include reporting on Commonwealth Edison's response time to DER project applications and time from receipt of an application until energy flows from the project to the distribution grid. A similarly structured metric was implemented for connections to the transmission grid where a generation project would connect at a higher transmission voltage.[38] These are report only metrics.

In its Track 2 Order in 2016, the NY-PSC directed the electric utilities to propose a DER interconnection survey process and associated EAM metrics. The utilities filed these in September 2016. The Commission, in March 2017, issued an order that determined that the utilities' proposed frameworks for the DG interconnection surveys and performance metrics did not fully address the need for improved interconnection processes, and required the utilities to submit a revised filing.

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[35] M. Whited, 2015, p. 89, citing Hawaii Public Utilities Commission ("HI PUC"). 2014. Decision and Order 31908 in Docket 2013-0141: Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[36] M. Whited, 2015, p. 94, citing Christopher Knittel 2002 "Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry." The Review of Economics and Statistics 84 (3).

[37] M. Whited, 2015, p. 85, citing Commonwealth Edison. 2014. Smart Grid Advanced Metering Annual Implementation Progress Report. Commonwealth Edison Company.

[38] *Id.*

Specifically, the Commission found:[39]

- The survey metric will use survey results of DG applicants with projects above 50 kW and up to 5 MW.[40] Each utility target will be considered in individual utility proceedings. Each utility is required to have a collaborative process to obtain input from stakeholders including DG applicants and developers on the appropriate target and must reflect the collaborative discussions and provide the basis for the target proposed.
- Regarding the survey to assess satisfaction with the interconnection process, utilities are required to survey DER interconnection applicants when the applicants have received preliminary review from the utility (a mid-point survey), and another survey once the DER application is complete. The surveys are to be phone and/or web-based. The survey design and vetting process will be thorough. The survey questions must be vetted through cognitive (how respondents understand the questions and respond) and field testing (to assess responses on survey questions). Finally, these surveys will include a core sequence of questions applicable to all utilities, used to determine the utilities' eligibility for the EAM.
- Failed applications will not be part of the EAM evaluation criteria. However, utilities must collect data on failed applications for a separate purpose.
- The DG interconnection EAM value will generally be consistent across utilities. Each utility is required to have a collaborative process to obtain input from stakeholders on the appropriate value.

Con Edison received approval for an interconnection EAM in January 2017 as part of a rate case.[41] The interconnection EAM covers DG projects between 50 kW and 5 MW, and measures results against three targets:

- Standard Interconnection Requirements (SIR) timeliness; these requirements include specific timelines by which interconnection projects must be approved.
- A survey of customer satisfaction conducted by an independent surveyor.
- An audit of failed applications conducted by an independent auditor.

Con Edison will convene a collaborative to seek agreement on the targets for the three EAM measures and other details. Although targets will be set and data collected in 2017, there will be no earning opportunity for Rate Year One. The earning opportunity for Rate Years Two and Three will be five basis points (0.05 percent of ROE; Con Edison's ROE is 9 percent) in each rate year.

The New York PSC also has a separate EAM specifically for DER deployments.

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[39] New York PSC. (2017, March 9). CASE 14-M-0101. Order Directing Modifications to the joint utilities proposed interconnection earning adjustment mechanism framework. Retrieved from http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

[40] The NY-PSC declined to apply an EAM to applications for projects under 50 kW.

[41] New York PSC, Case 16-E-0060, Case 16-G-0061, Case 16-E-0196, Order Approving Electric and Gas Rate Plans (for Con Edison), January 25, 2017. Retrieved from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2ED14916-F505-48AA-9AAB-3767554C380F

6.10. Operational incentives: Differing approaches to achieving system efficiency

Operational metrics can and often do focus on achieving system efficiencies. Different jurisdictions identify system efficiency differently based on their particular needs, configurations and priorities, with some focused on load factor improvement and peak reduction and others focused more broadly on reducing system losses, including theft and administrative and operational efficiency.

6.10.1. Denmark

The Danish TSO, Energinet.dk, a state-owned not-for-profit utility, is subject to non-profit "cost plus" regulation. Energinet.dk is not allowed to build up equity or pay dividends to its owner (Danish Ministry of Energy) and can only recover "necessary costs" by efficient operations and a "necessary return on capital." Revenues are therefore set to recover the necessary costs of efficient operation plus a modest interest on equity capital. The regulator, Energitilsynet (also known as DERA) can refuse the recovery of non-efficiently incurred costs. The guiding principle or goal is efficient operations.

The goal of the Danish net volume efficiency model is to encourage the most inefficient Distribution System Operators (DSOs) to become as efficient as the top 10 percent of DSOs within a four-year period. The main feature of the model, which is applied annually, is a cost index measuring the costs of an average DSO running a particular grid. Thus, the metric is the cost index measure, a benchmarking measure. The model allows individual DSO performance to be compared with its peers' relative performance despite differences in size and characteristics of specific grids. By limiting the number of cost elements analyzed to 23, the Danish benchmarking methodology, the "netvolumen" methodology, achieves an acceptable balance between efficiency benchmarking accuracy and the necessary resource requirements from the regulator (DERA) needed to accomplish this.[42] The benchmarking attempts to account for utility size and service territories: the net volume and quality of supply models are designed to take account of dissimilarities between DSOs size and the nature of their grids. However, there is little or no identification of areas in the economic benchmarking (the netvolumen model) where the DSO excels or performs particularly well. The measured outcome of the net volume model is an efficiency index comparing the actual cost incurred by a DSO in operating its grid with the costs incurred by an "average" DSO.

6.10.2. New York

The recent NY REV Order mandates EAMs related to peak reduction and load improvement factor:

- Each utility must propose a peak reduction target and a load factor improvement target. Each utility proposal for this EAM will meet a list of requirements including targets, an analysis

[42] In the netvolumen model, each DSO has annually reported its stock of 23 types of grid component. DERA obtains a measure of the DSO's net volume by multiplying the stock of each component by an estimated cost parameter including both operational cost and depreciation. The net volume effectively measures the cost that an "average" DSO would incur in operating each DSO's distribution network. Comparing this figure with the DSO's actual cost gives a cost-index for each DSO. This allows DERA to rank all DSOs in terms of operational efficiency and apply an annual efficiency factor to each DSO, designed to lift efficiency to that of the top 10 % of DSOs within four years.

based on a benefit-cost analysis (BCA) framework, and a proposed financial incentive for economic savings. These may include complementary strategies to build electric load, improve load factor, and reduce carbon emissions, such as encouraging conversion to electric vehicles, geothermal heat pumps, and other efficient and beneficial uses.

- Utilities must propose targets for peak reduction and load factor improvement over a period of five years. Individual utility targets may be either annual or cumulative with milestones. Peak reduction targets are required to establish either a specific MW objective for system peak or a percentage reduction from a defined MW amount. Both peak reduction and load factor improvement targets are required to be ambitious in size to encourage a portfolio approach beyond conventional programs. Targets and awards are to be established on a graduated basis that encompasses both moderate levels of achievement and superior results. Only positive earnings adjustments will be used for these initial EAMs, with the size of the adjustment graduated to the extent of achievement. To demonstrate achievement under this EAM, the Commission will examine the contribution of each component of the program, to avoid any incentive to achieve by reducing economic activity. This particular EAM is still under development at the time of writing this report.

New York is attempting to achieve a more efficient electrical grid by improving the load factor and reducing peak demand so electricity usage is more smoothly spread across different times of the day. The idea behind this improved load factor EAM is that capital infrastructure is utilized more efficiently if the infrastructure is used for more hours than just the peak periods.Implementing these concepts in January 2017, the NY-PSC approved a rate case for Con Edison that included a system efficiency EAM.[43] This EAM includes three metrics:

- Incremental system peak reduction; targets have already been set for this metric.
- Customer load factor; Con Edison will be further analyzing factors related to this EAM and proposing a metric for it in Rate Year Two.
- DER utilization; the DERs falling under this metric for Rate Year One are solar PVs, CHP, fuel cells, battery storage, demand response, thermal storage, heat pumps, and EV charging. DERs will be measured in terms of the annualized MWh produced, consumed, discharged, or reduced from incremental resources. Because not all DERs are individually metered or measured, MWh produced or consumed by incremental DERs will be determined on an annualized basis using fixed assumptions.

The maximum earning opportunity for these system efficiency metrics in Rate Year One is 4 basis points which is 0.04 percent of ROE in would be added to Con Edison's ROE is 9 percent.

In January 2017, the NY PSC approved a rate case for Con Edison that included several EAMs, including two energy efficiency metrics.[44] The first EE metric is for meeting or exceeding target levels for incremental GWh savings. EE incentives are not a new application of PBR. The second metric, developed through a collaborative process, is an energy intensity metric for both the

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[43] New York PSC, Order Approving Electric and Gas Rate Plans (for Con Edison).

[44] *Id.*

residential and commercial sectors. This metric is intended to incentivize efforts to decrease energy intensity beyond recent system trajectories (including energy savings from existing programs). Con Edison will earn this incentive if the decline in energy intensity improves beyond the trend 2010. The performance targets will be set on a rate class basis for residential kWh per customer and commercial kWh per employee at the end of rate year one at a declining intensity trajectory.[45] Con Edison can earn a maximum of 7.76 basis points in Rate Year One under this mechanism.

6.10.3. Puerto Rico

Puerto Rico is focusing on improving system efficiency by mandating performance metrics within its Integrated Resource Planning (IRP) process. The Legislative Assembly of the Commonwealth of Puerto Rico enacted Act 57-2014[46], which mandated performance metrics be adopted as part of the IRP process.[47] As the Legislative Assembly described it, "(w)e have been held as hostages of a poorly efficient energy system that excessively depends on oil as a fuel, and that does not provide the tools to promote our Island as a place of opportunities in the global market."[48] Thus, it is in this context, that the Puerto Rico Energy Commission (PREC) established performance metrics in the first set of IRP rules. Because of the significance with which the PREC views the need for the Puerto Rico Electric Power Authority (PREPA) to improve its performance on all fronts, the Commission has now established a separate proceeding to revisit and revise those metrics.[49]

On November 15, 2016, PREC issued its Notice of Investigation which commenced the process to review performance metrics more comprehensively. The Commission has already received comments from interested stakeholders.[50] The process will incorporate three separate components: a Commission investigation into PREPA's operations to assist in developing final performance metrics which will supercede the metrics set forth in the IRP rules; an independent engineering assessment of PREPA's operations focusing on the reliability and integrity of the entire transmission, distribution and generating system, especially in light of the extensive outage in September 2016; and rulemaking to create the new amended metrics. PREPA is a state-owned entity, however, making the assessment of rewards or penalties challenging.

A subsequent Order seeking comment from PREPA and interested stakeholders was issued on April

[45] Con Edison will use averages across the rate classes for the customers and employees. The energy use will tracked on 12-month rolling weather normalized monthly energy sales.

[46] Puerto Rico Energy Transformation and RELIEF Act, as amended. This legislation created a regulatory commission, the Puerto Rico Energy Commission (PREC) and included numerous regulatory provisions including an IRP and a timeframe (1 year) for the utility, the Puerto Rico Electric Power Authority (PREPA) to file.

[47] Act 57, §6C(h)(iv). Specifically, the law sets out detailed parameters which include: revenue per kilowatt-hour (kWh); operating and maintenance expenses per kWh; operating and maintenance expenses of the distribution system per customer; customer service expenses per customer; general and administrative expenses per customer; energy sustainability; emissions; total amount of energy used annually in Puerto Rico; total amount of energy used annually per capita, for Puerto Rico as a whole and separately for urban and non-urban areas; and total energy cost per capita, for Puerto Rico as a whole and separately for urban and non-urban areas.

[48] Id., Statement of Motives.

[49] Puerto Rico Commission Order 8594, May, 2015, IRP Rule, Article V.

[50] Energy Commission of Puerto Rico. (2016, November 15). In re: The Performance of the Puerto Rico Electric Power Authority, Case No. CEPR-IN-2016-0002.

27, 2017.[51] In that Order, categories of performance metrics were identified and listed under the following categories: overall system, generation, transmission and distribution, customer service, finance, planning, environmental, operations, IT, human resources, legal, renewable energy and demand-side managent. Each category has an identified list of potential metrics for which the Commission is seeking comment prior to drafting proposed rules. The operational metrics focus on efficiency in purchasing, warehousing, fleet, and fuel and are designed to improve tracking, reporting and efficiency in these categories as a means to cut costs and eliminate waste. Reporting requirements in other areas such as demand-side management, which measures reductions in peak and and energy usage, will also affect system efficiency. Because of the lack of accountability for PREPA prior to being regulated, most of the metrics are focused on reporting information to create a baseline from which to measure progress as new internal processes to improve performance are implemented. Thereafter, as part of the rulemaking, metrics may be put in place that would require progress on each metric reported. This proceeding is in the nascent stage of development as the Commission considers the best course of action.

Table 1: Draft Performance Metrics By Area[52]

Area	Metric	Unit of measure	Target
Overall system	CAIDI (Customer average interruption duration index)	minutes	146
Generation	Plant availability (system)	percentage	76%
T&D	SAIDI (System average interruption duration index) (system)	minutes	48
T&D	SAIFI (System average interruption frequency index) (system)	percentage	0.328%
Finance	Accounts Payable days outstanding	Days	35
Planning and Environmental	Timeliness of response to regulatory requests	Percentage	95%
Operations (purchasing)	Contracts as percent of spending	Percentage	80%
Operations (fleet)	Fleet out of service (system)	Percentage	20.5%

[51] Energy Commission of Puerto Rico. (2017, April 27). In re: The Performance of the Puerto Rico Electric Authority. Performance Metrics. Case No. CEPR-IN-2016-0002. Retrieved from: http://energia.pr.gov/wp-content/uploads/2017/04/Resolution-Performance-Metrics-CEPR-IN-2016-0002.pdf

[52] *Id.*

6.11. Operational efficiency: Financial solvency linked to efficiency improvement

Where state owned enterprises have been operating inefficiently for years and also need financial support due to costs exceeding revenue, it is possible to link continued state support to improving the efficiency of operations. A PBR mechanism being implemented India uses financial incentives to achieve dual objectives: 1) to increase the financial stability of distribution companies (discoms) in India and 2) increase energy efficiency.

Most distribution utilities in India are wholly-owned by their respective state governments, even though they have been regulated by independent regulators over the last 15+ years. Different states unbundled their state owned utilities differently and created the regulatory system at different points in time. The state governments own and operate their own DISCOMS, with little national government oversight. For political reasons, the states have provided inexpensive electricity at far below the actual cost of supply and delivery. As a result, for many decades, the state government-owned distribution companies (DISCOMs) have been incurring heavy losses (totaling losses of approximately Rs. 3.8 lakh crore (~$59.28 billion) and outstanding debt of approximately Rs. 4.3 lakh crore (~$67 billion) as of March 2015) because of average tariffs not keeping up with increasing costs, technical losses, theft, and limited bill recovery.

Financially stressed DISCOMs are not able to supply adequate power at affordable rates, which hampers quality of life and overall economic growth and development. Efforts towards 100 percent village electrification, 24x7 power supply, and ambitious clean energy targets are very unlikely to be achieved without financially solvent DISCOMs that are able to provide continuous power. Power outages also adversely affect nation-building initiatives that depend on facilities having reliable electricity, such as “Made in India” and “Digital India”. In addition, defaults on bank loans by financially distressed DISCOMs have the potential to seriously impact the banking sector and the economy at large.[53]

The Ujwal DISCOM Assurance Yojana (UDAY) is a performance incentive mechanism that was approved by the Union Cabinet of the federal Indian Government on 5th November, 2015. It is a scheme that is designed to facilitate financial & operational turnarounds of Indian DISCOMs. UDAY is active in 22 Indian states, and involves an agreement among the federal government, the state government, and the utility to achieve targets regarding utility financial stability, decreased power losses, improved end-use energy efficiency and efficiency in the agricultural sector, meeting renewable energy targets, and other goals that are relevant to that state.

UDAY operates through four initiatives (i) Improving operational efficiencies of DISCOMs; (ii) Reduction of cost of power; (iii) Reduction in interest cost of DISCOMs; (iv) Enforcing financial discipline on DISCOMs through alignment with State finances. Operational efficiency improvements like compulsory smart metering, upgradation of transformers, meters, and other network infrastructure, implementation of energy efficiency measures such as efficient LED bulbs, agricultural pumps, fans, and air conditioners aim to reduce the average Aggregate Technical and

[53] Press Information Bureau, Government of India. (2015, November 5). UDAY (Ujwal DISCOM Assurance Yojana) for financial turnaround of Power Distribution Companies. Retrieved from: http://pib.nic.in/newsite/PrintRelease.aspx?relid=130261.

Commercial (AT&C) loss from around 22 percent to 15 percent and eliminate the gap between Average Revenue Realized (ARR) & Average Cost of Supply (ACS) by 2018-19.[54]

UDAY recognizes the importance of aligning the goals of the central government, the state governments, and the DISCOMs. To that end, it provides customized guiding goals and directional incentives for each DISCOM in exchange for a financial support package.[55] In return for the bailout, the DISCOMs have been given target dates (2017 to 2019) by which they must meet certain efficiency parameters such as reduction in power lost through transmission, theft and faulty metering, installing smart meters and implementing geographic information system (GIS) mapping of areas with high losses. States will also have to ensure that power tariffs are revised regularly, so that the DISCOMS receive enough revenue to cover costs. The central government allows this additional debt on the state government books to not be counted against their fiscal obligations, and will also provide support for DISCOMs through its own schemes (e.g. rural electrification, network upgradation, etc.). The DISCOMs will also need to adopt certain tariff revisions, as prior tariffs were too low to compensate the utility for the actual cost of service, and tariffs were to be revised to reflect the actual costs. It is not clear if the new tariffs do this, or if they can be enforced on consumers.[56] Consequences for noncompliance are not clear.

Reductions in the cost of power are being achieved through measures such as increased supply of cheaper domestic coal, sourcing coal from more efficient plants, coal price rationalization based on GCV (Gross Calorific Value), supply of washed and crushed coal, and faster completion of transmission lines.

UDAY represents an innovative way to address larger systemic challenges of financial instability of utilities owned and operated by subnational governments. The innovative part of this scheme is that it recognizes and directly confronts the fact that financial liabilities of DISCOMs are the contingent liabilities of the respective States and need to be recognized as such. Debt of DISCOMs is de facto borrowing of States which is not counted in de jure borrowing. However, credit rating

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[54] AT&C losses refer to a combination of Technical Losses and Commercial Losses. Technical Losses are unavoidable losses due to flow of power in transmission and distribution systems which is result of network design, specifications of the equipments used in the network, and network operation parameters. Commercial losses are avoidable up to some extent which arise due to operational loopholes. It is a result of theft, metering issues, inefficient billing procedures, inadequate revenue collection, and non-remunerative tariff structure and subsidies.

% AT&C = { 1 - Billing Efficiency x Collection Efficiency } x 100

where:

Billing Efficiency: Total Billed Unit (kWH) / Total Input Energy (kWH) relative to the distribution asset

Collection Efficiency: Total Collected amount / Total Billed Amount

[55] Under the scheme, the State governments will take over three-fourths of the debt of their respective DISCOMs. The State governments will then issue ‘UDAY bonds’ to banks and other financial institutions to raise money to pay off the banks. The remaining 25 per cent of the DISCOM debt will be addressed in one of the two ways — conversion into lower interest rate loans by the lending banks, or via issuing DISCOM bonds backed by State government guarantee (which helps bring down interesting rates). Madhu, M. (2016, March 28). All you wanted to know about UDAY. The Hindu Business Line. Retrieved from http://www.thehindubusinessline.com/opinion/all-you-wanted-to-know-about-uday/article8406121.ece

[56] Currently 17 out of the 22 states have reported AT&C losses for this year, and the total losses across all 17 states is 22.49 percent. The goal is for each state to have 15 percent AT&C losses or less. https://www.uday.gov.in/atc_india.php. Additionally, tariff revisions were required as part of the MOU for each state, as the utility needs state buy-in to accomplish these tariff revisions. Tariff revisions have been filed in 19 of 22 states. In this respect the MOUs have been a success. Government of India, Ministry of Power.(undated). UDAY National Dashboard. Retrieved from https://www.uday.gov.in/atc_india.php

agencies and multilateral agencies are conscious of this de facto debt in their appraisals.

Figure 2. UDAY state/discom quarterly performance ranking (as of March 31, 2017)[57]

To date UDAY has been well received by the states that have signed up for it.[58] This is encouraging as the states are key stakeholders to the success of UDAY. Quarterly rankings for state/DISCOM performance is publicized on the UDAY national dashboard, which encourages state and DISCOM good performance.

6.12. Operational metrics: Reliability

As part of a grid modernization initiative in the U.S. State of Illinois, the Illinois Commerce Commission (ICC) adopted a PBR formula rate tariff.[59] These tariffs were approved under Illinois's Energy Infrastructure Modernization Act which authorized $3.2 billion in grid hardening and smart meter investments. The guiding principle of the act and tariff is to achieve increased grid reliability and operational efficiency by offering the utilities increased certainly around capital investments ranging from distribution reclosers, substation improvements, pole reinforcements, undergrounding targeted lines, and vegetation management.[60]

This Illinois tariff approved formula rates for participating utilities providing greater utility confidence that grid modernization expenses would be found prudent with a set rate of return to be

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[57] Government of India, Ministry of Power. (2017). UDAY National Dashboard. Retrieved from https://www.uday.gov.in/home.php

[58] Adebare, A. (2016, January 25). A Closer look at the Ujwal Discom Assurance Yojana Uday Scheme. Mondaq. Retrieved from http://www.mondaq.com/india/x/460820/Oil+Gas+Electricity/A+Closer+Look+At+The+Ujwal+Discom+Assurance+Yojana+Uday+Scheme

[59] 220 ILCS 5/16-108.5.

[60] McCabe, A; Ghoshal, O, & Peters B, A Formula for Grid Modernization? Manuscript of article later published in Public Utilities Fortnightly.

adjusted based on known factors annually. In exchange for this formula rate treatment, participating utilities are required to file multi-year metrics with the ICC to improve performance over a 10-year period, including reliability performance.

After installing grid automation and more intelligent sensors and the range of approved grid hardening and smart grid invesments described above, the utilities reported improvements in outage frequency and duration.[61] But the utilities have failed ot meet the 75 percent improvement performance criteria set by the ICC and been penalized with a 5-basis-point reduction in authorized ROE as a result. This reduction of ROE resulted in an approximate $2 million reduction in Commonwealth Edison's roughly $2.5 billion annual revenue requirement.[62] This is a negative incentive scheme which imposes a relatively low penalty reduction in an approved formula rate when reliability criteria is not met.

Setting reliability goals, performance criteria, or metrics can be difficult. It is important not to fall into the "no-amount-of-reliability-is-enough" trap because reliability investments are limitless. The amount of reliability that regulators should require and how to measure it are perennial utility questions: how much reliability should be required or another way to ask the question is how much reliability do customers want to pay for their electricity service? The Canadian Province of Alberta recognized this quandary squarely in its decision rejecting a reward-based PIM for exceeding expected reliability standards:

> ". . . in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher price of service quality levels that they may not want or cannot afford." [63]

Norwegian regulators approached the reliability quandary by asking utility customers how much they value reliability using customer surveys to construct a willingness-to-pay curve for different levels of system reliability. The Norwegians then use a PBR scheme to have their utilities internalize the reliability valuation by customers. Norway uses revenue cap regulation to control utility costs. It allows utilities to retain cost savings from operating below approved costs. Because revenue cap regulation can create an incentive to cut costs in ways the impact system reliability, this system adjusts utility revenues each year based on the costs of outages to customers. Thus, if outages increase, utility revenue is reduced—or if outages are reduced below a baseline level, the utility receives higher revenues the next year.[64]

Under this system, a Norwegian utility seeking to maximize profits will increase expenditures to the point where the marginal cost of increased reliability equals the customers' willingness to pay (as shown in the customer surveys). The Norwegian reliability PBR is designed to achieve the optimal level of reliability. The optimal reliability level is where marginal utility costs equal marginal

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[61] Both utilities, Ameren and Commonwealth Edison, report reliability improvements; see https://www.icc.illinois.gov/downloads/public/edocket/406271.pdf and https://www.icc.illinois.gov/downloads/public/edocket/402546.pdf.

[62] McCabe, A; et al, p. 5.

[63] M. Whited et al, 2015, p. 41.

[64] M. Whited et al, 2015, p. 35.

customer benefits determined in the customer surveys. Use of the survey instrument to determine the optimal level of reliability and then motiving the utility with positive and negative incentives is a particularly innovative approach to implementing reliability goals.

6.13. Modified fuel adjustment clauses to address higher ramping rates for integration of renewables

Fuel adjustment clauses are common to allow utilities to pass-through costs of fuel which can move up and down between rates case due to market fluctuations. However, these clauses can provide a disincentive for efficient generator management because they remove utility risk in achieving efficient power production from fuels when the fuel cost is subject to 100 percent pass-through to customers, and thus saving fuel does not benefit the utility. Once this was recognized, conditioning cost recovery on certain power plant efficiency levels, or adaption of shared savings mechanisms, has become more common. Experience with these modified fuel adjustment mechanisms, in which the utility bears some risk for fuel cost overruns and can keep some savings from efficient operations, suggests that such clauses do indeed encourage operational efficiencies. One study concluded that the modified fuel adjustment clauses resulted in 9 percent more output per given inputs than utilities with a 100 percent pass-through mechanism of all fuel costs.

This experience with the incentive structure of fuel adjustment clauses and modifications is mentioned here because it demonstrates the operational efficiency requirements do work in practice when carefully designed. Moreover, this demonstrates how various aspects of the utility business work in tandem, and that performance-based regulation must be an iterative process as new impacts are discovered such as a penalty for fuel-units in performing ramping up an down to accommodate higher renewable resources on the system. It is also informative of new challenges such as encouraging operation and development of resources with high ramping rates, voltage support and frequency regulation as more renewables are integrated into grid operations. Experience with modified fuel adjustment clauses suggests carefully implemented incentives to provide these advanced grid supports are achievable and will take effort and experience to perfect.

6.14. Performance-based regulatory approaches to promote customer empowerment

PBR can improve utility focus on customer satisfaction and can also actively promote customer empowerment. Customer empowerment is defined here as the ability of customers to provide feedback on utility service, demand-side energy options, and the ability to see publicly reported performance data on their utility.

Under the U.K.'s RIIO, customer satisfaction has increased significantly. This increase in satisfaction appears to some extent to be related to the published rankings of utility performance. Customers are able to see the satisfaction rankings, and based on these rankings or their own personal experience, will switch suppliers.[65]

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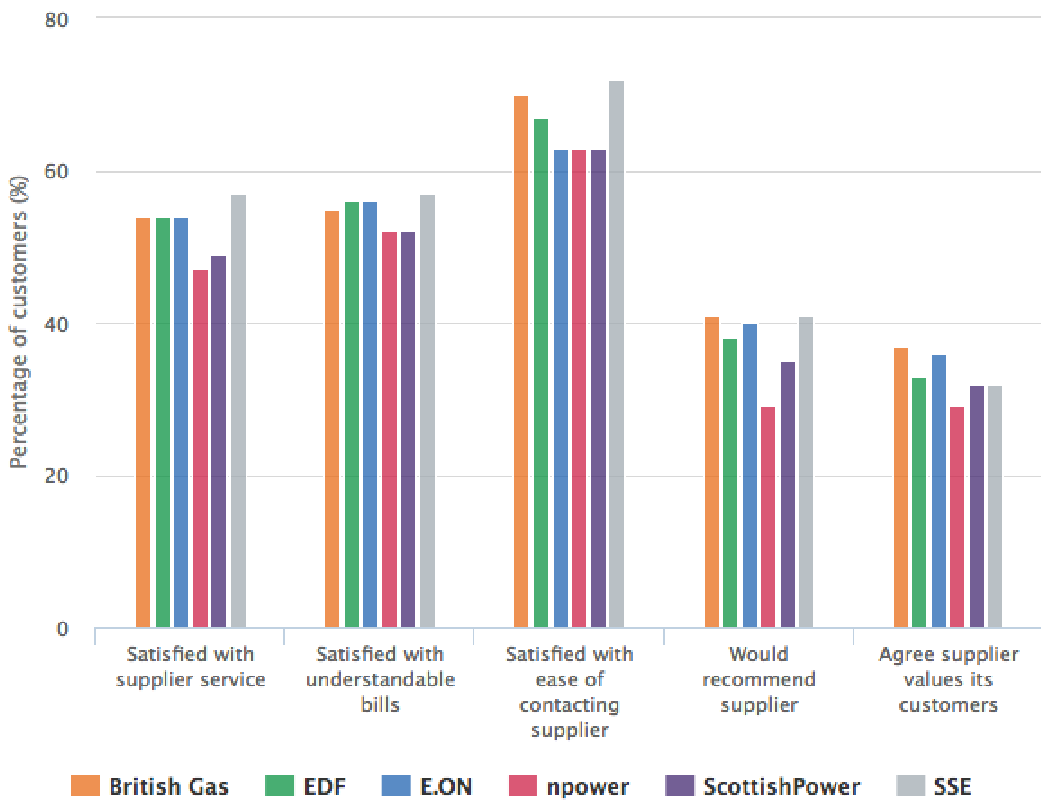
[65] The Guardian. (2017). Energy bills: are UK customers finally starting to switch supplier? Retrieved from

Figure 3. Customer satisfaction in the UK[66]



Likewise, Denmark annually reviews its utilities' performance with its benchmarking scheme. The outcome of the benchmarking processes, in terms of efficiencies made and reductions in allowed DSO revenues, are reported in the DERA annual report to share the efficiency findings with the Danish public. In Denmark, as with many other EU Member States, customers can switch their supplier (energy retailer) but can't switch their DSO. Customers are not therefore "empowered" in that they cannot exercise choice in terms of their DSO. However, the benchmarking scheme does to some extent compensate for this lock-in by giving customers some comfort that their DSO is required to strive to become as efficient as the best 10 percent of the DSO community. The Danish annual report is a less pronounced effort than RIIO's but directionally similar in that it endeavors to provide utility performance data on compliance with regulatory benchmarking.[67]

The island of Puerto Rico, has included a customer service category among its many categories of metrics. In its IRP proceeding, Puerto Rico, adopted operation metrics for customer satisfaction, system efficiency and system operations as follows:

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https://www.theguardian.com/money/2017/feb/27/energy-bills-more-uk-customers-are-moving-supplier-figures-show

[66] Ofgem. (2016). Customer Satisfactioin: Six large electricity suppliers. Retrieved from https://www.ofgem.gov.uk/chart/customer-satisfaction-six-large-electricity-suppliers

[67] The DERA annual report reports efficiency data for the DSO community as a whole and is therefore "directionally similar" to Ofgem's RIIO annual report, however the latter and its associated documents provide far more detailed information for each individual DSO. One reason why DERA may report on a DSO community basis is the number of DSOs involved.

Customer Satisfaction Metrics in Puerto Rico

- Number of formal and informal customer complaints, including response time to resolve complaints and a short description of the complaint and how it was resolved;
- Response time to service requests and outages;
- Residential customer satisfaction, based upon a survey of residential customers conducted by an independent entity with expertise in conducting customer surveys;
- Business customer satisfaction, based upon a survey of business customers conducted by an independent entity with expertise in conducting customer surveys.

Another form of customer empowerment is to expand on past customer satisfaction metrics to show expanded measures of customer satisfaction. The Puerto Rico Energy Commission also focused in its recent PBR decision on customer empowerment through a series of metrics related to customer choice to make customer-sited energy management decisions. The Commission promulgated the following metrics related to customer empowerment:

Table 2. Puerto Rico Metrics for Customer Empowerment

Energy efficiency	Number and percent of customers served by programs, annual and lifetime energy savings, levelized program costs per lifetime energy saved
Demand response	Number and percent of customers served by programs, annual and lifetime demand savings, levelized program costs per MW saved
Distributed generation	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Energy storage	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Electric vehicles	Number of installations per year and cumulative, capacity (MW) of installations per year and cumulative
Information availability	Number of customers able to access hourly usage
Time-varying rates	Number of customers on time-varying rates.[68]

The relationship that the Puerto Rico Energy Commission perceives between customer satisfaction, efficiency and system operations is consistent with 21st century regulatory approaches that link customer satisfaction with the measure of system efficiency.

Scorecards, with clear metrics and mandated formats approved by regulatory authorities, and designed with broad utility and stakeholder input, may become a hallmark of 21st century power

[68] Puerto Rico Energy Commission. (2015). Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority. Order 8594, Article V. Other topics include reliability, system costs and environmental goals.

sector regulation. Taking a page from RIIO success with increased customer satisfaction, the NY PSC will require utility scorecards for simplified reporting to ratepayers and the public under NY REV. Development of these scorecards is underway with performance criteria and metrics likely to be settled by 2018 in NY. The NY PSC ordered the parties of the REV proceeding to undertake a collaborative effort to specify metrics that should be maintained as scorecards to measure desired outcomes, although scorecards would not have any direct impact on regulated earnings. The following scorecard categories are to be used initially, and are still in the process of being defined and developed; other categories may be explored in the future:

- System utilization and efficiency
- DER penetration
- Time-of-use rate efficacy
- Market development
- Market-based revenues
- Carbon reduction
- Conversion of fossil-fueled end uses
- Customer satisfaction
- Customer enhancement (includes affordability)
- Affordability
- Resilience

6.15. Performance-based regulatory approaches to support competition

Energy service companies, including DER providers – in partnership with new advanced technology companies – are offering services to small customers previously only available to larger customers, including energy efficiency, distributed generation, smart energy management systems, and energy storage. Some services and products can compete directly with utility offerings and reduce the need for utility services. Utilities thus may perceive a competitive risk and make interconnection or provision of some services difficult. To address anti-competitive utility behavior, certain metrics can encourage utility cooperation to deliver required services, such as system interconnection application processing time or the number of DERs on the system. New York is moving forward with DER provider surveys to assess utility performance in multiple DER-provider/utility interactions, as well as utility compliance with interconnection application timeframes. For example, under New York's Standardized Interconnection Requirements (SIR), which are now part of the state's interconnection EAM, utilities are required to determine if an interconnection application is complete, meets the SIR technical requirements, and is approved for interconnection, all within 10 business days after recept of the application for systems of 50 kW or less. There are similar timeline requirements for other steps in the process, and for systems larger than 50 kW, with the goal of ensuring that applications are processed in a timely manner.[69] Care can also be taken to ensure that incentives are even-handed for utilities and other DER providers. The U.K. regulatory authority, Ofgem, strives to ensure that any incentive benefit available to utilities is also available to independent providers when competition exists for a particular service such as connection services.[70]

Incentives can also work in a contrary direction: to free up utilities to respond to mounting competition. Multi-year rate plans are often adopted to allow utilities more flexibility in marketing when faced with competition and to allow superior utility performance to earn superior returns over a multiple year period. Of course, multi-year plans could encourage anti-competitive behavior as well, if not addressed through other mechanisms such as discussed herein.

6.16. Compliance with codes of conduct in support of competition

Codes of conduct govern how utilities (and their affiliates) interact with companies that compete with them. Historically monopolies did not have competition. In the 21st century, competitive opportunities can emerge through restructuring of the electric industry[71] or through energy services companies[72]. Even in restructured markets, utilities maintain monopoly positions over certain services and will often have superior economic resources and access to customer and market information and system knowledge that competing companies cannot match. If a utility can use its economic and information advantages, there is the risk it can drive out competitors and operate as a deregulated monopoly, exercising market power. While the rules to prevent anti-competitive behavior can be detailed and in certain respect quite distinct among jurisdictions, there are basic principles that govern the establishment of rules:

1. Discrimination in providing access to essential services should be prohibited.
2. There should be no sharing of competitive information among companies affiliated with the utility.
3. Cross-subsidization by the utility to benefit a competitive enterprise, such as an affiliate, should be prohibited and carefully monitored.[73]

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[69] For more details, see: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/SIR%20Final%203-17.pdf

[70] M. Whited, 2015, p. 72, citing Ofgem. 2012. Strategy Consultation for the RIIO-ED1 Electricity Distribution Price Control: Outputs, Incentives and Innovation. Supplementary Annex to RIIO-ED1 Overview Paper. Office of Gas and Electricity Markets.

[71] Seventeen states and the District of Columbia have adopted electric retail choice. US Energy Information Administration. (2012). Electricity Retail Choice 2010. Retrieved from http://www.eia.gov/todayinenergy/detail.cfm?id=6250

[72] See, for example, the NY Reforming the Energy Vision proceedings, NY DPU CASE 14-M-0101, Feb.26,2015, among others; DC PSC, Formal Case No.1130, In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability; California PUC, Distribution Resource Plan, http://www.cpuc.ca.gov/PUC/energy/drp/

[73] See Migden-Ostrander, J. (2015, November). Power Sector Reform: Codes of Conduct for the Future. Electricity Journal, 28(6), p.4. Retrieved from https://www.researchgate.net/publication/285216738_Power_Sector_Reform_Codes_of_Conduct_for_the_Future

Many U.S. states enacted codes of conduct as part of their restructuring procedures.[74] Examples of codes of conduct include the New York Public Service Commission's Order as part of the REV proceedings,[75] PEPCO Holdings,[76] and Dominion Resources Inc. as between its affiliates in North Carolina and Virginia.[77] Texas also has a comprehensive code of conduct addressing the affiliate relationship.[78] All of these codes of conduct are fairly similar in substance and put into practice the three basic principles described above. These concepts can be applied to multiple aspects of a utility business in which a regulated utility or its affiliate enters the market to offer a competitive service. Table 3 on the following page describes various common aspects of utility codes of conduct for interacting with their own affiliate companies, as well as competitors.

For codes of conduct to be effective there needs to be regulatory oversight, including requirements for compliance plans and audits to ensure that the codes of conduct are being adhered to. The utility should maintain a compliance procedure and log in which it records all informal complaints and their disposition. The regulator needs to have the ability to levy penalties for noncompliance.[79]

It is unusual for violations of codes of conduct to be adjudicated by regulatory officials. Such investigations are not common and a PBR scheme can incentivize compliance (or incentivize noncompliance) much more efficiently than a regulatory adjudication. Further, the expected nature of compliance and violations as deviations from acceptable norms may form the basis for creating a negative incentive or penalty.

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A PBR incentive for compliance with codes of conduct would be closely associated in concept with support for competitive DER markets, but be distinct because it would focus on corporate separation and compliance with codes of conduct. The PBR metrics could track the number of complaints of violations made to the utility. Complaints most often go directly to the utility; thus, a requirement to keep a log to document the complaints is necessary. Since competitive companies are dependent on good will and utility relationships, they may be reluctant to file complaints. For that reason, the utility log of complaints can be a useful tool. The logs will indicate the resolution of

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[74] An example of a code of conduct filed in Ohio by the Customer Coalition for Choice in Electricity. Before the Public Utilities Commission of Ohio, In the Matter of the Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan Pursuant to Chapter 4928 Ohio Revised Code, Case No. 99-1141-EL-ORD, Comments of Coalition for Choice in Electricity, Appendix C, October 13, 1999.

[75] State of New York Public Service Commission. (2016, September 15). Order Setting Standards for Codes of Conduct. Case Nos. 15-M-0501 and 14-M-0101. Retrieved from: https://www.energymarketers.com/Documents/utility_code_of_conduct_DER_order.pdf

[76] Pepco Holdings. (undated). Codes of Conduct. Retrieved from http://www.pepcoholdings.com/codes-of-conduct-/

[77] Dominion. (undated). Code of Conduct Governing the Relationships between Dominion North Carolina Power, its Affiliates and the Nonpublic Utiltiy Operations of Virgina Electric and Power Company. Retrieved from https://www.dom.com/library/domcom/pdfs/north-carolina-power/rates/shared/codes-of-conduct.pdf

[78] Texas PUC. (undated). §25.272. Code of Conduct for Electric Utilities and Their Affiliates. Retrieved from https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.272/25.272.pdf

[79] Migden-Ostrander, 2015.

issues as well as spot recurring problems. Unresolved matters or serious complaints would be addressed at the regulator level through separate complaint processes. The information obtained by the regulator can be used to form the basis of metrics regarding utility interaction with competitive DER providers.

Table 3. Utility Code of Conduct Areas

Type	Description
Nondiscrimination	Utility provision of the same services and information to all competitors including its own affiliates, without preferential treatment for its affiliate. Utility provision of the same information sharing and disclosure to all competitors including prohibition on sharing information with affiliates that is not shared with competitors
Corporate Identification and Logo	Use of a different name and logo from the parent to eliminate customer confusion and avoid a name-recognition competitive advantage.
Goods and Services	Transfer of goods and services to, sharing of facilities with, an affiliate only at market price to the regulated utility for any goods or services received to avoid a subsidy from ratepayers and prevent it from gaining a competitive advantage. Sharing equipment and costs sharing does not occur between the utility and distribution company except for perhaps corporate services.
Joint Purchases	The utility should not be allowed to make joint purchases with their affiliate that are associated with the marketing of the affiliate's products and services.
Corporate Support[80]	Shared corporate support must be priced to prevent subsidies, be recorded and made available for review.
Employees	The utility and their affiliate(s) do not jointly employ the same people, with the only exception being shared directors and officers from the corporate parent or holding company.

6.17. Peak load reduction enabled by demand response

Peak load reduction is a key cost-avoidance opportunity for systems with growing generation, transmission and distribution peaks. If peak load reduction is a policy goal that the jurisdiction seeks to implement, a PBR mechanism that rewards the utility for reducing peak load by a specified means can be designed and implemented. There are many strategies and measures to reduce peak load. One is the use of demand response addressed here. Another is deployment of DERs to reduce

[80] Corporate support means overall corporate oversight, governance, support systems, and personnel Any shared corporate support between the utility and the competitive entity should be priced to prevent subsidies and should be recorded and made available for review. The use of combined corporate support should exclude the opportunity to transfer confidential information, provide preferential treatment or an unfair competitive advantage, or lead to customer confusion.

peak among other goals for DER deployment addressed above. A third is as a peak reduction system efficiency measure such as pursued under NY REV also addressed above.[81]

A regulatory decision reached in Illinois in 2013 required a performance metric be developed by Commonwealth Edison to reduce peak load through demand response. This involves load impact reductions measured in MW of peak load reduction from the summer peak due to smart meter enabled demand response programs administered by the utility.[82] While these performance metrics do not include any rewards or penalties, they provide valuable information for regulators and stakeholders to monitor whether customers are receiving the full benefit of the multi-billion dollar smart grid infrastructure investment. In addition, these metrics provide valuable information going forward for regulators if it is determined that a financial reward or penalty is warranted.[83]

6.18. Customers enrolled in time-varying rates

Sending an accurate price signal to customers has been an issue in many jurisdictions. Because system costs vary considerably by time of day, and by season for both generating and delivering electricity, the theory is that customers will make more efficient decisions for themselves and the system if they see the relative scarcity or abundance of electricity service reflected in their price. Customers would for instance see that they can save money by running a large appliance on the weekend rather than during the week. However, customers can only adjust their use to reflect pricing and scarcity if the customer's price accurately reflects the higher cost structure of the generators as well as utility plant during peak hours.[84]

For example, a regulatory decision reached in the U.S. state of Illinois in 2013 requires a performance metric be developed by Commonwealth Edison to track customers enrolled in time-varying rates.[85] This includes at least four different metrics:

1. Number of residential customer on the utility tariff with time-variant or dynamic pricing in each delivery class, and reported as a percentage of customers taking supply from that retail supplier with both numbers and percentage by rate class.

2. Number of residential customers serviced by retail suppliers which have requested monthly data interchange for interval data (meaning the customers accounts will be set up for monthly data transfer of interval usage data) and reported as a percentage of customers taking supply from that retail supplier with both numbers and percentage by rate class.

3 & 4. And then the same two metrics as above for small commercial customers.[86]

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[81] See discussion of NY REV EAM goals for peak reduction in Section 6.10.2.

[82] M. Whited, 2015, p. 85-86, citing Commonwealth Edison. 2014. Smart Grid Advanced Metering Annual Implementation Progress Report. Commonwealth Edison Company.

[83] *Id.*

[84] It is relatively common for electricity to be priced by peak-hours/intervals where there are wholesale markets for electricity but pricing utility transmission and distribution rates by peak usage (to capture demand on the T&D system) has historically been accomplished with demand charges for larger customers. Now with advanced metering infrastructure, T&D pricing can be done for all customers to approximate demand on the system on intervals as well.

[85] Puerto Rico is also looking at reporting metrics of TOU rates.

[86] M. Whited, 2015, p. 85, citing Commonwealth Edison. 2014. Smart Grid Advanced Metering Annual Implementation Progress Report.

The Illinois reporting metrics illustrate significant interest in Illinois in assuring that customers have accurate pricing signals. Other jurisdictions share this interest as well – for example, Puerto Rico wants its utilities to adopt information availability practices by reporting on the number of customers able to access hourly usage data and the number of customers on time-varying rates.[87]

6.19. PBR for smart meter deployment

European law requires the "implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity supply market." France has incorporated this requirement into law and code. In response, the Commission de Regulation de l'energie (CRE) proposed a smart-grid roll out for Électricité Réseau Distribution France (ERDF), one of the distribution system operators in France. The objective of ERDF's project for its low voltage (LV) smart metering system (≤ 36 kVA) is to deploy 35 million smart-meters between the last quarter of 2015 and the end of 2021. The target deployment rate is 90 percent of all meters.

CRE found that implementing the *Linky* project (so called for the name of the metering system to be implemented) would generate risks other than those ERDF regularly faces when carrying out its normal utilities functions because of the project's exceptional technical, industrial and financial features. The *Linky* project differs from standard ERDF projects in terms of cost, but also in its expected benefits and its deployment time (slightly over six years). Given the size of the project and the need to guard against any increase in costs or forecasted completion times, a specific regulatory framework has been implemented that gives ERDF incentives to control investment costs, comply with the deployment timetable, and to guarantee performance of the system installed.

The PBR incentive awards ERDF a bonus of 300 basis points to be attributed to assets used in the *Linky* project between January 1st, 2015 and December 31st, 2021 (excluding those used for experimental pilots and standard electronic meters). The bonus is awarded throughout the asset life time.

The incentive bonus is comprised of two parts:

- Part one (200 basis points) is calculated based on the performance of ERDF on controlling investment costs and complying with the deployment timetable (points 1 and 2 below);
- Part two (100 basis points) is calculated based on on the performance of the smart metering system in meeting the objectives of the project and delivering a high quality of service (point 3 below).

The basis points and incentives for the three components are as follows:

<u>1. Control investment costs:</u>

a. ERDF is penalized from the first euro of additional cost because it loses the bonus of 200 basis points on this additional cost. If the additional costs exceed 5 percent, any further

Commonwealth Edison Company.

[87]Puerto Rico Energy Commission. (2015). Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority. Order 8594, Article V. Other topics with subtopics include reliability, system costs and environmental goals.

costs are not remunerated (i.e. no bonus and no base-rate remuneration);

b. From the first euro saved, ERDF keeps a bonus equal in amount to the bonus as it would have been with no saving. Grid users benefit from reduced capital charges (lower depreciation and base-rate remuneration).

<u>2. Comply with the deployment timetable:</u>

This incentive focusses on the number of meters that are installed and able to communicate, compared to the forecasted deployment timetable. Monitoring takes place regularly throughout deployment. If the forecasted deployment percentages are not achieved, this generates penalties.

In order to ensure that complying with the deployment timetable does not jeopardize the quality of the installation, the CRE has put in place a financial incentive relating to the percentage of return visits after a *Linky* meter is installed during the deployment. It will also monitor the percentage of complaints related to deployment.

<u>3. Guarantee the performance level expected from the *Linky* metering system:</u>

The quality of service for the *Linky* metering system is a key element not only in improving the functioning of the electricity market but also in realizing benefits in terms of technical intervention (estimated at €1.0 billion (2014) at current value) and meter reading (estimated at €0.7 billion (2014) at current value). These benefits are directly proportional to the performance level of the metering system. Poor performance would thus have a significant impact on the economic value of the *Linky* project.

In this context, the incentive-based regulation mechanism defined by the CRE aims to induce ERDF to reach the performance level necessary to obtain these benefits and improve the functioning of the electricity market, to the benefit of consumers. The CRE thus gives ERDF a bonus of 100 basis points to induce it to maintain a performance level for the metering system that meets expectations over the long term. Conversely, any shortcoming in performance will reduce this bonus.

If the expected performance rates are not reached, penalties are assessed. The metrics prompting penalties are based on poor performance of the following:

1. Percentage of successful remote meter readings by day;
2. Percentage of actual monthly readings published by Ginko4;
3. Percentage availability of customer internet portal;
4. Percentage of *Linky* meters with no remotely-read figures for the last two months;
5. Percentage of remote services carried out on the day suppliers requested them;
6. Percentage of meters activated within the defined time following an order for Mobile Peak.

Additionally, there is ongoing evaluation of the incentives on the following timescale:

- An annual review of investment costs, with financial incentives (or penalties) if costs drift or are reduced;
- A biennial review of compliance with the forecasted deployment timetable, with penalties for late deployment;
- A final settlement of the cost and time-scale incentives at the theoretical end of large-scale deployment (i.e. 2021) in order to induce ERDF to make up any delays or cost variances during the large-scale deployment phase. Conversely, if ERDF's performance has deteriorated over the deployment period, it will be more heavily penalized;
- An annual review of the system's performance in terms of quality of service delivered from the start of the deployment phase. Penalties are payable if the predefined outputs are not achieved.

Utility operating charges affected by the *Linky* project will be monitored specifically, particularly when the next tariffs are being defined. During each tariff year, the CRE will ensure that the pattern of operating charges presented by ERDF is consistent with the projections both for cost reductions (in reading metering costs, carrying out technical work and reducing line losses) and for the costs of operating the metering system (related mainly to the information systems (IS) and system administration).

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