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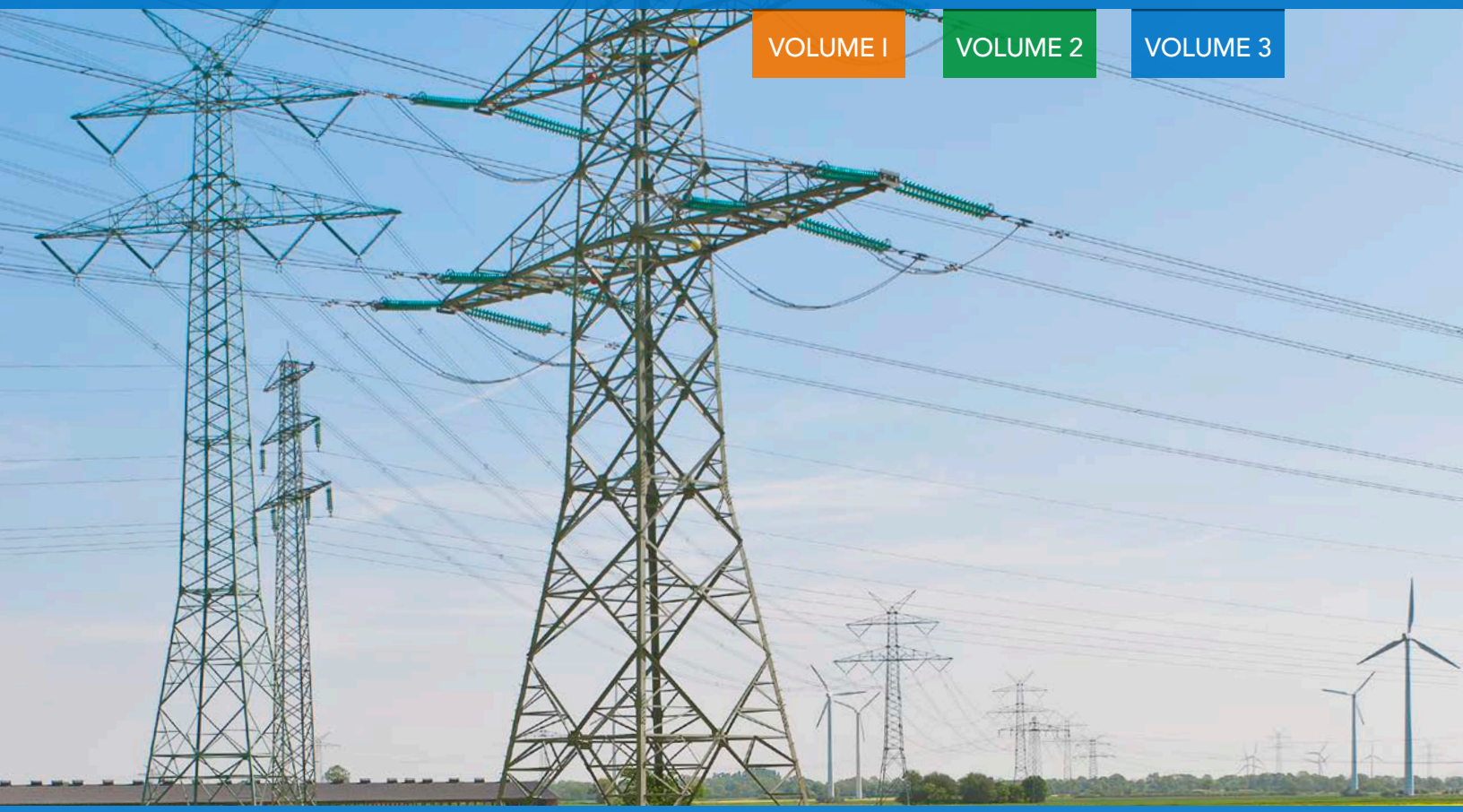

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Accelerating the transformation of power systems

CLEAN ENERGY MINISTERIAL
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Next-Generation Performance-Based Regulation

Volume 3: Innovative Examples from Around the World

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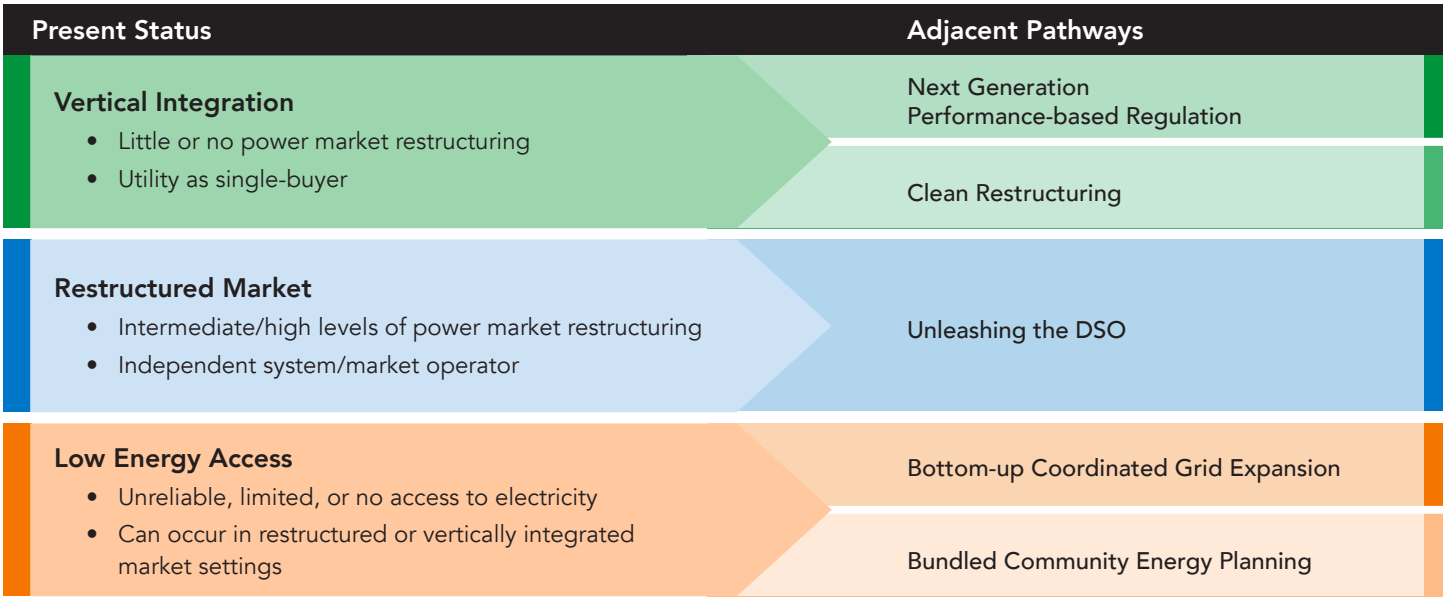
The Next-Generation Performance-Based Regulation Report in Three Volumes

This three-volume report is based on the material found in *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*,[1] which, like this report, was created for the 21st Century Power Partnership (21CPP). Since 2012, the 21CPP—an initiative of the Clean Energy Ministerial—has been examining critical issues facing the power sector across the globe. Under the direction of the National Renewable Energy Laboratory (NREL), 21CPP provides thought leadership to identify the best ideas, models, and innovations for the modern power sector that can be implemented by utilities and governments around the world.

An earlier 21CPP report, *Power Systems of the Future*,[2] published in 2015, summarizes the key forces driving power sector transformation around the world and identifies the viable pathways that have emerged globally for power sector transformation, organized by starting point as illustrated in Figure P-1. In 2016, the 21CPP published an in-depth report describing the Clean Restructuring pathway originally elucidated in *Power Systems of the Future*. A related pathway identified in *Power Systems of the Future* was Next-Generation Performance-Based Regulation, and this report builds on that.

Figure P-1. Present status and adjacent pathways to power system transformation



Source: Zinaman, O., Miller, M., Adil A., Arent, D., Cochran, J., Vora, R., Aggarwal, S. et al. 2015. *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-62611. http://www.nrel.gov/docs/fy15osti/62611.pdf.

[1] Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., et al. 2017. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/68512.pdf.

[2] Zinaman, O., Miller, M., Adil A., Arent, D., Cochran, J., Vora, R., Aggarwal, S. et al. 2015. *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-62611. http://www.nrel.gov/docs/fy15osti/62611.pdf.

With this report, we have divided the full *Next-Generation Performance-Based Regulation* report into three volumes:

1. *Next-Generation Performance-Based Regulation*
   Volume 1: Introduction—Global Lessons for Success
2. *Next-Generation Performance-Based Regulation*
   Volume 2: Primer—Essential Elements of Design and Implementation
3. *Next-Generation Performance-Based Regulation*
   Volume 3: Innovative Examples from Around the World.

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List of Acronyms

AT&C	aggregate technical and commercial
DER	distributed energy resource
DG	distributed generation
DISCOM	distribution company
DSO	distribution system operator
EAM	earnings adjustment mechanism
ERDF	Électricité Réseau Distribution France
ESCO	energy service company
EV	electric vehicle
IRP	integrated resource planning
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NY REV	New York's Reforming the Energy Vision
NY-PSC	New York Public Service Commission
PBR	performance-based regulation
PIM	performance incentive mechanism
PREC	Puerto Rico Energy Commission
PREPA	Puerto Rico Electric Power Authority
PV	photovoltaic
RIIO	Revenue=Incentives+Innovation+Outputs
ROE	return on equity
T&D	transmission and distribution
UDAY	Ujwal DISCOM Assurance Yojana
VRE	variable renewable energy

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1 Introduction

In this volume, Volume 3, of the *Next-Generation Performance-Based Regulation* report, we focus on how performance-based regulation (PBR) can be used in this era of rapidly changing technological trends, and we survey current innovative PBR options in the world. First, we examine current technological trends in the power sector and evaluate how these trends are changing the structure. These trends include the penetration of disruptive technologies, decentralization of supply, enrollment of the demand side in the power sector, increase in cross-sectoral integration, and increase in intelligence and digitalization of networks. We then explore how these trends are challenging the current system and how PBRs can play a role in power sector transformation.

We feature examples of innovative PBR designs from around the world. These examples are meant to show the wide range of ways PBRs can be used and the variety of goals the mechanisms can achieve. Some of the examples are theoretical and are suggestions for new ways to apply PBRs, and others are real-world examples.

2 How PBRs Can Support Power Sector Transformation

This section highlights key trends in the power sector, what we think we know about the path these changes may take, and what we cannot know, and it notes the implications of these trends for power sector regulation. The section suggests paths forward for regulation to harness and accommodate changes that are to some extent difficult to entirely predict.

- **Key Point 1:** The acceleration of technology innovation in power markets is challenging many long-held paradigms and requiring new approaches to planning, procurement, system operations, public policy, and regulation.
- **Key Point 2:** PBR is a form of the regulation that can harness disruption while providing utilities with the flexibility to reach the measurable performance criteria. It does so by specifying goals for utility performance, utility outputs, and outcomes for consumers and society, while staying agnostic to the exact means of delivery.

We are now entering a period of rapid change in many power sectors around the world that is motivated by a range of technology, policy, market, and business model drivers. The next section takes stock of certain key evolutions in the power sector and what we know about the path these changes will take, and it assesses the implications of these trends for power sector regulation.

2.1 What Is Changing

After nearly a century of fairly incremental technology improvements in the power sector, the industry is now experiencing a period of rapid change brought about by technological innovation and evolving public policy objectives. This section briefly highlights five key trends that have implications for power sector regulatory approaches:

- Penetration of Disruptive Technologies (Section 2.1.1)
- Decentralization of Supply (Section 2.1.2)
- Enrollment of the Demand Side (Section 2.1.3)
- Increasing Cross-Sectoral Integration (Section 2.1.4)
- Increasing Intelligence and Digitalization of Networks (Section 2.1.5).

2.1.1 Penetration of Disruptive Technologies

Technology disruption is driving transformation in many industries, including in the power sector. Cost reductions of variable renewable energy (VRE) (e.g., wind and solar)—in combination with competitive procurement structures—are making these resources the lowest-cost form of new-build generation in many contexts, and they are driving rapid deployment. Battery energy storage, although still nascent in many respects, is an increasingly popular option to manage the supply and demand of electricity, support stability in local grids, and provide the flexibility needed to integrate VRE resources. Technologies such as LED bulbs and lights are already helping flatten load growth in many jurisdictions. A range of other emerging end-use technologies, coupled with automation and information and communication technology, present novel opportunities to enroll the demand side of the power sector and promote greater integration of power with other sectors. In general, the growing ubiquity of technology innovation in power markets is challenging many long-held paradigms and requiring new approaches to planning, procurement, system operations, public policy, and regulation.

2.1.2 Decentralization of Supply

The combination of increasing VRE deployment and the increase of distributed energy resources (DERs)[3] is resulting in an increasing decentralization of supply in some power markets. Geographically dispersed fleets of VRE resources are changing network investment strategies and creating new challenges for regulators to evaluate the prudency of network investments. Sharply declining DER costs, particularly for distributed photovoltaic (PV) systems, are accelerating public policy dialogues about the desired role of distribution utilities in 21st century power systems in which some consumers produce their own electricity. What constitutes fair compensation for consumers selling power to the grid has also proven to be a complex and contentious issue. Furthermore, with the power grid largely designed for unidirectional power flow, utilities and regulators are now grappling with how best to efficiently invest in their network infrastructure to enable greater integration. This decentralization of supply is driving a need for greater operational cohesion of distributed resources,[4] and the rise of VRE and DERs is thus strongly complemented by the trend of increasing intelligence and digitalization of the power sector.

2.1.3 Enrollment of the Demand Side

The demand side of the power sector has historically been unresponsive to supply-side conditions.[5] New technology is now enabling customers from all segments to behave more responsively to the real-time price of energy and enabling them to receive payments for shifting their demand when grid conditions require it. This is occurring through both regulated utility programs and private third parties; in both scenarios, an entity is responsible for aggregating groups of customers, calling on them to reduce demand when needed, and facilitating a payment for services. Demand response programs are growing in number and sophistication, with some aggregation schemes allowing participation in wholesale power markets. There are still many technical and regulatory barriers to entry, with unresolved issues in many markets concerning, among other things: access to customer and market data, the role of third-party aggregators, and reliability of and fair compensation for demand response resources. As increasing amounts of low-cost VRE drive the need for greater system flexibility, the aggregation of demand response may prove to be a valuable resource for many power systems.[6]

Customer load factor[7] and load shape[8] data are very valuable for determining the optimal customer, circuit, and distributed resource approaches for the most efficient system design. DERs offer the potential to serve a range of customer loads with distinct load factors and load shapes to realize efficiencies simultaneously for the customer and the broader utility system. However, a utility may or may not benefit financially from some DER solutions and could in fact lose revenue under certain circumstances. If utilities exercise sole control over consumer load data and are not required to share, there exists a very real possibility that this information will never be shared with DER providers or customers, as it may show a solution that saves consumers money or reduces utility investments.

[3] DERs are modular, geographically dispersed, and often smaller-scale technologies that allow consumers to produce their own energy, manage their consumption, and participate more actively in the power system. They include distributed generation such as solar PV, storage, electric vehicles, demand response, heating and cooling systems, and smart home automation.

[4] Zinaman, O., Miller, M., Adil, A., Arent, D., Cochran, J., Vora, R., Aggarwal, S. et al. 2015. *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/62611.pdf.

[5] A notable exception is the example of large industrial customers (e.g., aluminum smelters) that enter into interruptible load demand response contracts with utilities, often for contingency events.

[6] In competitive markets, the energy service company (ESCO) business model is predicated on monetizing a portion of the value associated with saving consumers money on their electricity bills. ESCO revenues are generated by sharing the savings achieved and are thus driven by reductions in savings from retail prices. Whether that model can now extend into energy supply and potentially wholesale markets is an open question.

[7] Load factor is the ratio of a customer's or location's average or actual electricity usage to peak load, usually over a period such as a billing period or annually (average load as a percentage of peak load).

[8] Load shape is a user's or location's energy consumption pattern over time, such as daily, monthly, seasonally, or yearly.

Utility management, whether the utility is privately or publicly owned, is often motivated toward large investments that increase rate base (the Averch-Johnson effect).[9] Traditional cost-of-service regulation sets a rate of return on rate base,[10] and so the utility is incentivized to increase revenue (and earnings for shareholders if privately owned) by investing in its own plant. Early forms of PBR were designed to counter the Averch-Johnson effect by allowing utilities to keep savings from efficient operations. This early form of PBR—multi-year rate plan mechanisms—set electric rates and adjusted them for inflation and productivity. Utilities that operate with fewer costs than what was approved in the last rate case (adjusted for inflation and productivity) can keep some or all of the savings. In this way, multi-year rate plans reward cost control (see Section 3.2.1). This means that between rate-setting proceedings, prices increase as a function of inflation, and are reduced by expected productivity gains, but not as a function of capital investment. Not only do DER investments potentially reduce the need for utility investments, DERs also reduce utility sales volume, which reduces utility revenue in the short run. The utility desire to build rate base and increase the volume of sales (the "throughput incentive") gives utilities two strong structural incentives to resist DERs, even in scenarios in which they are the lowest-cost resource option available. These factors can become barriers to deploying DER solutions in some jurisdictions.

2.1.4 Increasing Cross-Sectoral Integration

The electrification of previously un-electrified economic sectors, such as transportation and heating (in some jurisdictions), presents further opportunity to enroll the demand side and reduce system costs. Electric vehicles (EVs) may offer a near-term opportunity for utilities to grow demand for electricity,[11] with over 2 million plug-in vehicles on the road globally by the end of 2016 and substantial immediate-term growth expected.[12] EVs, through intelligent charging protocols, can use their batteries to provide local power quality services, avoid expensive peaking generation for the system, and help balance supply and demand to integrate VRE. Time-of-use pricing schemes can enable EV owners to reduce their electricity bills by charging when energy prices are low. Similar to EVs, electric heating loads such as heat pumps or district heating systems can be enrolled and aggregated to provide valuable grid services. In this case, the thermal inertia of residences and buildings can be used as a form of storage to help shift demand with a minimal impact on the heating services provided. In general, this increasing trend of electrification and cross-sectoral integration may increase stress on local grids, and it may require careful automation protocols and sufficiently granular pricing mechanisms to prevent network infrastructure from becoming overloaded. In an era of increasing DERs (and stagnant/shrinking demand in developed economies), the prospect of increasing sectoral integration and electrification offers a new and perhaps much-needed opportunity for utilities to grow revenues.

2.1.5 Increasing Intelligence and Digitalization of Networks

In addition to innovative generation and demand-side technologies, new investment is flowing toward a broader interconnected system of intelligent networks; this has largely been enabled by the growing ubiquity of sensors, data collection systems, and information and communication technology, and driven by a need for greater cohesion among distributed resources within the power system. As discussed in the previous subsections, the prospect of aggregation and coordination of many individual customers, some of whom may be generating

[9] The Averch-Johnson effect is identified by economists as the tendency of regulated companies to engage in excess capital investments to increase their profits.

[10] For publicly owned systems with no private shareholders, there is still revenue and earnings pressure. Universally, lenders (bondholders) demand certain coverage ratios to justify investment-grade interest rates and enable reasonable retail rates that drive revenue concerns. Other hidden incentives for growth include federal and global aid programs in which loan administrators pursue volume of loans and grants placed. A related concern is setting administrator salaries keyed to the size of the electric system.

[11] In an era of growing rooftop solar (and stagnant or shrinking demand in developed economies), the prospect presents an exciting opportunity to expand business for many utilities.

[12] International Energy Agency. 2016. *Global EV Outlook: Beyond One Million Cars*. https://www.iea.org/publications/freepublications/publication/Global_EV_Outlook_2016.pdf.

their own power, requires the implementation of increasingly smart and real-time controls throughout the network. Networks are increasingly rich with data, and through automation and real-time analysis, there are substantial opportunities to unlock demand-side resources,[13] increase situational awareness and resiliency, and send granular price signals to consumers and producers to incentivize behavior. However, this raises a host of new issues around, among other things: communication, management, and privacy of network data; growing cyber and physical security considerations; appropriate equipment and communication standards; establishing appropriate levels of data access for the private sector; and equitable cost and risk allocations for network investments.

The regulator's job in overseeing a utility with significant customer-sited resources will involve new challenges and functions. The question then becomes, how can a regulator with new challenges interact in the most productive manner with utilities and customers to achieve efficiencies and higher levels of service for customers who increasingly have differentiated load shapes, usage, and even generation patterns.

2.2 What We Cannot Know About What is Changing

Although we cannot predict the precise evolution of the power systems of the future, we are able to identify trends. Here too there is a caveat: we do not know all the trends. But we do have a sense of the existing trends. This is tricky as well, however, because we do not know at what pace and how each specific trend will develop. Or indeed, whether another trend will overtake and influence what we know is changing. So, although we have a good sense of direction, we are not able to predict pace, precise development scenarios, and most especially disruptive trends. To accommodate technological, adoption, and disruptive certainty, we want to design regulatory structures to accommodate future outcomes consistent with a wide variety of future scenarios, all of which are plausible.

In the 20th century, power grid and power sector regulatory paradigms were designed to have flexibility to address uncertainties such as demand variability (daily and seasonal variations, fuel price fluctuations, and failures of system components, such as failures of one or more generators). The underlying energy markets for traditional fossil fuels can be very dynamic. These markets can be subnational, national, and international, and fuel prices are often volatile, so supply input economics vary just as electricity demand has varied. The regulatory models adequately addressed these uncertainties.

In the 21st century, advanced energy technologies such as battery storage and grid-enabled vehicle charging create new resource types with new capabilities and integration challenges. Battery storage may enable demand management heretofore unheard of, and looks sometimes like a generator, sometimes like a customer asset, and other times like a distribution or transmission asset. Regulators are still grappling with how to classify storage under traditional regulation and understand its true value to the grid.

Technologies, networks, and new applications are emerging very quickly and so are consumer expectations of the grid to provide the value they anticipate. Some consumers expect more opportunities for increased control over their energy use, and they assume new technologies will provide them with attractive options. As with transformative technology, business models of industries will start, end, or evolve as the waves of change move forward. Recent history is replete with transformative technology change that was not foreseen by experts.

Can regulators and utilities know what's changing? Energy consumption has been over-predicted for six decades, which suggests that even the experts and regulators predict energy trends incorrectly. Figure 1 illustrates this error, showing the projected natural gas well head price projections, and comparing it with actual prices.

[13] At a time when renewable electricity is increasing variability on the supply side, intelligent demand will be an increasingly important dispatchable resource. Jager, D., Bucquet, C., van Rooijen, S., and Petrick, K. 2015. *Implementing Agreement for Renewable Energy Technology Deployment. Annual Report 2014.* International Energy Agency. http://iea-retd.org/documents/2015/05/2014-annual-report-iea-retd.pdf.

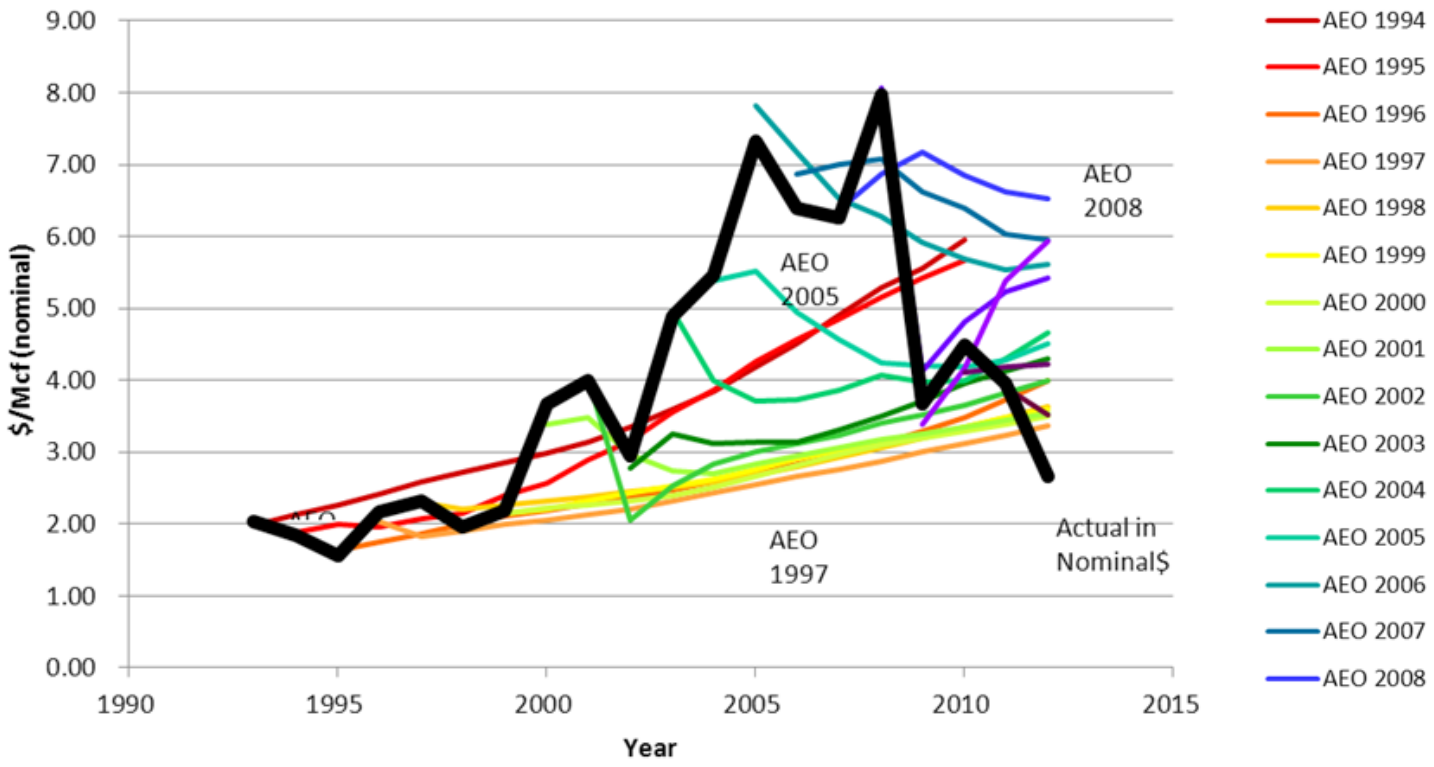

Figure 1. Historic Natural Gas Wellhead Price Projections (in color each year) and Actual (in black).

Source: US Energy Information Agency, *Annual Energy Outlook Retrospective Review: Evaluation of 2013 and Prior Reference*

2.3 Regulation for the Era of Disruptive Technology

With so many transformational elements permeating the power sector, there is a growing focus on governing institutions to enable change and "get out of the way" of technological innovation. In practice, regulatory bodies are often at the center of these dialogues around how exactly, and at what speed, to allow technological disruption and business model innovation to enter the market. Although regulatory approaches must be satisfactorily customized and locally appropriate, we offer that a new wave of "*regulation that harnesses disruption*" is needed to keep pace with technological innovation. In principle, this disruptive regulation should be sufficiently flexible to adjust to an ever-changing suite of technology, resource, social, political, and energy market drivers, but at the same time hold steadfast and unwavering in the ultimate outcomes desired for consumers.

We further offer that PBR—by specifying expectations of utility performance and outcomes for consumers while staying agnostic to the exact means of delivery—constitutes a form of this much-needed regulation that harnesses disruption. We consider PBR as one tool in a broader toolbox in the transition toward flexible regulatory and market structures that rewards utilities that adapt or evolve in reaction to market and technology change.[14]

[14] Miller, M., Martinot, E., Cox, S., Speer, B., Zinaman, O., Booth, S., Zissler, R. et al. 2015. *Status Report on Power System Transformation*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/63366.pdf.
Zinaman, O., Miller, M., Adil, A., Arent, D., Cochran, J., Vora, R., Aggarwal, S. et al. 2015. *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/62611.pdf.

3 Innovative PBR Approaches

This section offers innovative approaches to reach 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 previous sections, PBR has evolved greatly since its inception over two decades ago. Performance-based regulation is now being used in a variety of jurisdictions worldwide in innovative and wide-ranging ways. A selection of innovative PBRs and performance incentive mechanisms (PIMs) is examined here by topic area. Unlike the PBRs listed previously, not all the mechanisms here have been implemented, nor do they have a lengthy history of implementation. These mechanisms are examples of innovative ways in which PBR is being applied. It is anticipated that, like the predecessors examined in previous pages, the experience with the mechanisms listed here will yield further lessons in the future on best practices. This is not an exhaustive list, but it should provide an overview and inspiration for the different ways PBR is or could be applied to different aspects of electric utility regulation. Section 3.1 lists areas that could utilize PBR, but which have not yet been proposed. Section 3.2 lists innovative applications of PBR and PIMs.

3.1 Areas Ripe for PBRs

3.1.1 Incentives for Water Savings

There have been significant regulatory responses to water shortages in various jurisdictions. Until very recently, California has been faced with a multi-year drought, but its concern with reducing water usage by power plants is longstanding, 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 megawatt-hour (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. Performance-based regulation, although uncommon in the electricity sector, has been used in the water utility sector to encourage water conservation in areas with water shortages. The Southern Nevada Water Authority, for example, has very aggressive pricing and lawn removal programs.

3.1.2 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 greenhouse gas 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; this was in a settlement reached in Illinois in 2013 regarding cost justification for advanced metering infrastructure. The settlement—by parties interested in justifying the cost of advanced metering infrastructure—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 modifications).[15] The settlement includes metrics to calculate power plant marginal emissions changes and changes in generator dispatch attributable to load shifting of smart meter customers compared to non-advanced metering infrastructure customers on an hourly level. Other metrics are to be developed for greenhouse gases 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.[16] Reporting and development of these metrics may provide sufficient regulator and utility experience, which can then be refined and 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 prerequisites to successful PBR.

3.1.3 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 (e.g., circuit-specific system average interruption duration index or system average interruption frequency index) 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), DER investments may help 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.[17] 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.

Sharing of location energy data to designate high-cost utility areas for DER development can be structured into a PBR mechanism. 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, that is, have the highest system value. This is what New York did with the Brooklyn-Queens Demand Management

[15] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 84.

[16] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 86.

[17] The Regulatory Assistance Project. 2000. *Performance-Based Regulation for Distribution Utilities*. Montpelier, VT: The Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 40.

project discussed in Volume 2; the utility provided incentives such as direct payments to DER providers or customers, direct DER investment by the utility where legally authorized, or facilitated competitive procurements among DER providers, with payments to DER vendors capped at the utility savings, to direct DER development to these high-cost areas.[18] The utility was allowed to recover the costs of DER assets acquired by it and also an additional return on equity (ROE) adder if it was successful in acquiring adequate demand-side reductions through its DER acquisition process. Although this can be described as a shared savings system (and this program is described in Section 6.2.7), implementation occurred through an ROE adder and allowed recovery of utility costs for direct utility procurement of DER assets in a particular high-cost area. 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, although New York's Brooklyn-Queens project 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 an ROE adder. These total savings can be expressed in short-run marginal avoided costs of major substation 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 Brooklyn-Queens project 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.[19] The Brooklyn-Queens project 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.

3.1.4 Incentives for EV Rate Education and Charging Station Deployment

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 for EVs presents design dilemmas with which jurisdictions. For example, should the focus on educating consumers be on home charging rates or 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 use 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 on home charging rates is riper for utility education and consumer interface. Indeed, modest utility support for home charging infrastructure could increase 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 United States. 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.

[18] The Regulatory Assistance Project. 2000, p. 41.

[19] The Regulatory Assistance Project. 2000, p. 41, Footnote 16.

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 goal is to prepare infrastructure for charging station completion, a measurable performance criterion might be utility make-ready work performed for EV charging station completion. National Grid has proposed such a performance criterion in Massachusetts that will be considered by the Massachusetts Department of Public Utilities. 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 National Grid, with a maximum award representing 5.5% 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% of the program target. The maximum award of $1.2 million would be earned if 175 sites (125% of the program target) were activated. The petition is currently under consideration.[20]

3.1.5 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 once they achieved a dominant position in the market. In the 21st century, competitive opportunities could emerge through restructuring of the electric industry[21] or through energy services companies.[22] 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. Although the rules to prevent anticompetitive behavior can be detailed and in a 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.[23]

Many U.S. states enacted codes of conduct as part of their restructuring procedures.[24] Examples of codes of conduct include the New York Public Service Commission (NY-PSC) order as part of the proceedings on New York's Reforming the Energy Vision (NY REV),[25] Pepco Holdings,[26] and Dominion Resources, Inc. as between its affiliates in North Carolina and Virginia.[27] Texas also has a comprehensive

[20] National Grid. 2017 (January 20). Petition of National Grid for Pre-Approval of Electric Vehicle Market Development Program, and of Electric Vehicle Program Provision. Docket 17-13. http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=17-13%2fInitial_Filing.pdf.

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

[22] See for example, the New York Reforming the Energy Vision proceedings, NY DPU Case 14-M-0101, February 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/.

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

[24] An example of a code of conduct filed in Ohio by the Customer Coalition for Choice in Electricity. 1999 (October 13). 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. Appendix C. http://dis.puc.state.oh.us/TiffToPDf/J_YLZ8DECRL5YXDH.pdf.

[25] NY-PSC. 2016 (September 15). Order Setting Standards for Codes of Conduct. Case Nos. 15-M-0501 and 14-M-0101. https://www.energymarketers.com/Documents/utility_code_of_conduct_DER_order.pdf.

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

[27] Dominion. (undated). Code of Conduct Governing the Relationships Between Dominion North Carolina Power, its Affiliates and the Nonpublic Utility Operations of Virginia Electric and Power Company.

Table 1. 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 of sharing information with affiliates that is not shared with competitors
Corporate identification and logos	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, and 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 cost 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 its affiliate that are associated with the marketing of the affiliate's products and services.
Corporate support[29]	Shared corporate support must be priced to prevent subsidies, be recorded, and be made available for review.
Employees	The utility and its 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.

code of conduct addressing the affiliate relationship.[28] All these codes of conduct are fairly similar in substance and put into practice the three basic principles described previously. 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 1 describes various common aspects of utility codes of conduct for utilities interacting with their own affiliate companies, as well as with competitors.

For codes of conduct to be effective there needs to be regulatory oversight, including requirements for compliance plans and audits to ensure adherence. 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 non-compliance.[30] It is unusual for violations of codes of conduct to be adjudicated by regulatory officials, and a PBR scheme can incentivize compliance (or incentivize noncompliance) much more efficiently than a regulatory adjudication.

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

[29] Corporate support means overall corporate oversight, governance, support systems, and personnel. Any corporate support shared by 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, should not provide preferential treatment or an unfair competitive advantage, and should not lead to customer confusion.

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

Furthermore, the expected nature of compliance and violations as deviations from acceptable norms may form the basis for creating a negative incentive or penalty.

A PBR incentive for compliance with codes of conduct would be closely associated in concept with support for competitive DER markets, but it would also 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. Because competitive companies depend on goodwill 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 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.

3.2 Innovative PBRs that are in Operation

The following PBRs or PIMs are innovative examples of how jurisdictions around the world are using PBR.

3.2.1 Incentives for DER Implementation

PBR frameworks are ripe with opportunity to help address the negative incentives utilities face—and which are often inherent to traditional cost-of-service regulation constructs—to achieving efficient levels of DER deployment. PBR can be used to set incentives for greater DER penetration. Performance-based regulation for DERs can seek greater system efficiency through specific directional incentives tied to DER provider satisfaction, or DER deployment metrics of other system measures.

DER deployment is often assessed in terms of (1) number of DER systems deployed, (2) the total installed capacity of DER on a system (kW or MW), or (3) if applicable, the total amount of energy produced from DER units (kWh or MWh). These three fundamental metrics represent merely the first steps in PBR for DER deployment, and they can be used to establish directional incentives that lead to greater system efficiency through DER deployment. It can be difficult to translate directional incentives to measure utility DER penetration, formulate performance criteria, and set actual metrics for DER performance. Assessing DER provider satisfaction using a well-developed survey represents one way to develop innovative measures such as those being implemented in New York. DER incentives are relatively new, and as such, are being structured in a variety of forms that doubtless will evolve as some are judged successful and others less so.

3.2.1.1 Distributed Energy Resource Provider Satisfaction

The NY REV initiative is an exemplar of this PBR approach. It is designed to establish coordinated PBR to motivate utilities to look for system efficiencies whether they are achieved on the grid through utility grid-level investments or at customer premises through customer and third-party DER solutions. NY REV's incentives are designed to reward utilities for DER provider satisfaction and customer satisfaction while encouraging strong transparency. The NY REV initiative recognizes that system efficiency can be achieved through either utility investments or customer and third-party DER solutions, and it attempts to alter utility incentives to allow for an assessment of the most cost-effective and beneficial set of solutions among utility, customer, and third-party providers.

One difficult issue jurisdictions will consider in structuring PBR mechanisms focused on DER is setting an appropriate baseline of expected business as usual (i.e., no utility intervention) DER deployment. DER markets and technologies are rapidly evolving, and investment decisions are made by consumers for a variety of reasons that can be difficult to project or model. Notably, many DER deployment drivers are outside the direct control or influence of utilities. This makes it difficult to set a PBR mechanism to determine which DER deployment should be attributed to the utility, and what would have happened without any utility involvement. As a result, directly attributing specific utility activities to DER deployment (i.e., measuring a

utility's value-add) may be a challenge. A baseline must be developed before a PBR mechanism can be created, and starting with an *ex ante* baseline is difficult because DER technologies markets are emerging (see Section 4.1.1 of Volume 2 of this report for more on setting baselines). The inability to develop a baseline or predict DER deployment trends poses a challenge in developing directional incentives as well as measurable performance criteria and PBR metrics. If a baseline is developed, any DER deployment in excess of this baseline could in theory be attributed to the utility, for the purposes of PBR. In practice, however, formulating proper baseline assessments against which to create a performance incentive for DERs is challenging. Although methodologies to conduct baseline DER deployment estimates are outside the scope of this report, it is important to note that conducting these studies in public, and with sufficient stakeholder review and input, is a good practice that can only increase the validity of the estimates. The approach taken in NY REV of using sophisticated DER provider surveys to assess utility performance in DER facilitation has a significant virtue of avoiding the challenging task of developing a baseline against which to measure utility facilitation of DER deployment.

The NY-PSC recognized that establishing a baseline for DER deployment is particularly difficult. Rather than simply track DER interconnection requests with no way of evaluating the quality of the interconnection process, the NY-PSC instead focuses its PBR for DER on a survey of DER providers. The sophisticated survey of DER providers, which is still under development in the stakeholder process, is meant to assess how well utilities are working with DER developers on interconnections and identifying targeted locations on the grid system where DER may have high value to reduce load.

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 simplifying measuring interconnection times, application, or quantity, 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 on how the utility handles interconnection requests. These exogenous factors include local market dynamics and third-party energy service company activities that influence the quantity of DERs installed but are largely exogenous to utility operations. Refinement and implementation of these DER provider surveys will occur in upcoming years in New York. Text Box 1 discusses how California regulators induced utilities to consider non-wires solutions to distribution system reliability needs.

The New York PBR survey of DER providers will in theory incentivize timely and quality reviews of DER interconnection requests. Utility performance will be assessed based on surveys of DER providers and satisfaction of standardized interconnection requirements[31] as a threshold condition. Favorable survey outcomes will result in a positive earning adjustment under NY REV. For projects over 50 kW, the earnings adjustment mechanism (EAM) will have the following components:

1. A threshold condition based on adherence to the timeliness requirements established in the standardized interconnection requirements

[31] Standardized interconnection requirements 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 greater than 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.

Text Box 1. Non-Wires Alternative Requirement in California

In December 2016, the California Public Utilities Commission 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 reconducting 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.[1] DERs that can meet some or all of these needs include energy efficiency, demand response, storage, and distributed PV and other distributed generation (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, 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% on the annual contract cost of the contracted non-wires alternative.

[1] CPUC (California Public Utilities Commission). 2016. Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot. Rulemaking 14(10) 003, p. 8.

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
   b. A periodic and selective third-party audit of failed applications to assess accuracy, fairness, and key drivers of failure to support continual process improvement.

The NY-PSC will also consider on a case-by-case basis the negative earning adjustments for failure to meet established standards.

As part of NY REV, the NY-PSC has a separate EAM specifically for DER deployments. A DER 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.[32] The DERs falling under this EAM initially are solar PV systems, combined heat and power, 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.

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

3.2.1.2 Solar Distributed Generation

A guiding goal of a PBR regime can be to encourage solar distributed generation (DG) or to encourage utility, consumer, and solar DG developer communication and cooperation in effective interconnection. A good first step toward this goal is to facilitate transparency on connection levels, including methods to facilitate communication between the utility, customers, developers, and the public.

In 2013, Hawaii adopted utility performance metrics for DER deployment. These included measurements of the number of net energy metering[33] program participants and installed solar DG capacity, as well as enrollment numbers for utility demand response and storage programs. These metrics are to be posted on the utilities' websites to facilitate transparency of information on DER levels for utility customers.[34] There are no incentives associated with these metrics.

To address the customer and stakeholder's desire for information on DER deployments and application processing, Massachusetts used "dashboards."[35] Dashboards are computerized summaries of key data on specific topics such as solar DG deployment presented on a web-based portal. Although not an incentive mechanism per se, dashboards can set up very effective communication methods with customers, the public, and DER developers. Moreover, graphical presentation of dashboard data involves presentation of DER information (number of units, capacity, energy produced, geography) that comprises a number of metrics that set public reporting obligations similar to specific performance criteria. Dashboard and energy data 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.

3.2.2 Incentives for Sharing Utility Data

Using real-time energy cost and usage data systems is critical to optimize the efficiency of energy production and delivery.[36] However, utilities are inherently reluctant to do so, as there are barriers to overcome and no incentive to do so. Sharing these 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.[37] If 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 because these data would provide opportunities for them to offer alternative solution sets to consumers, provide lower costs of customer acquisition, and compete with utilities for certain

[33] Hawaii has since terminated solar net energy metering.

[34] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 89.

[35] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 32.

[36] Fox-Penner, P. 2010. *Smart Power: Climate Change, the Smart Grid and the Future of Electric Utilities*. Island Press; Valochi, Michael, John Juliano, and Allan Schurr. 2010. *Switching Perspectives: Creating New Business Models for a Changing World of Energy*. IBM Inst. for Business Value.

[37] 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 NY-PSC noted that "utilities will have four ways of achieving earnings: traditional COS 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." NY-PSC. 2016 (May 19). Case No. 14-M-0101. Order Adopting a Ratemaking and Utility Revenue Model Policy Framework.

services.[38] The need for utility performance incentives and corresponding metrics that will motivate utilities to provide data to third-party energy technology companies 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 under development.

3.2.3 Renewable Energy Performance Metrics

Hawaii adopted performance metrics to require utilities to reveal all renewable energy used by each utility, whether utility-based or distributed. The Hawaii guiding goals and directional incentives identified for refinement and further consideration include system renewable energy (excluding customer-sited generation), total renewable energy generated (including DG), renewable energy curtailments, and compliance with renewable portfolio standards. These metrics are to be posted on the utilities' websites to facilitate customer access and private market decision-making and planning.[39]

In March 2015, Hawaii further ordered development of metrics, a website, and a review process for renewable metrics. 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."[40] This process would establish and post to a website metrics for the following renewable energy metrics:[41]

1. System renewable energy metric
2. Renewable portfolio standard compliance
3. Total renewable energy metric
4. Number of net energy metering program participants and capacity of net energy metering program.
5. The development of these metrics will facilitate transparency with customers, stakeholders, and the public.

3.2.4 Operational Incentives: Improved Power Plant Performance

There is a history of California regulators developing system operational incentives when its utilities were vertically integrated in the late 1980s and 1990s. During this time, nuclear plant costs were so high 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 the Diablo Canyon nuclear power plant 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 and escalated only for inflation. The performance guiding goal was to achieve increased hours of generation. Under this settlement, the plant earned 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 this error, California 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 tenfold. The result was utility payments for nuclear power at much higher replacement power

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

[39] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 89.

[40] Hawaii Public Utility Commission. 2014 (February 7). Docket 2013-0141. Order No. 31098. https://dms.puc.hawaii.gov/dms/DocketSearch.

[41] Hawaii Public Utility Commission. 2014 (February 7). Docket 2013-0141. Order No. 31098. https://dms.puc.hawaii.gov/dms/DocketSearch.

costs than were anticipated.[42] Both mechanisms were subsequently modified because of a perception that the utility was overcompensated for the cost of nuclear generation.

Both 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 prices adequately. To the extent the pricing formulas were intended to incent purchases from these nuclear power plants, they succeeded. However, to the extent the formulas were intended to save ratepayers money, the pricing failed to incorporate mechanisms that ensured ratepayer savings would occur.

Moving forward two decades, there is perhaps an appreciation for testing PBR and metrics first before adopting full-fledged and potentially expensive performance incentives. In 2014, Hawaii adopted performance metrics for generator performance. These include equivalent availability factor, equivalent forced outage rate demand, and equivalent forced outage factor. These metrics were ordered to be posted on the utilities' websites to facilitate stakeholder and customer access.[43] As noted in Section 5.2, while reporting obligations for certain performance criteria or metrics are a weak form of PBR, they are PBR nonetheless. The requirement that utilities track, analyze, and report specific information can affect utility behavior and may be precedent to establishing incentives.[44]

3.2.5 Operational Incentives: Improved Interconnection Request Response Times

Performance-based metrics have been used to incentivize utilities to improve interconnection request response times for DERs. How these mechanisms are structured varies widely by jurisdiction. The Illinois Commerce Commission approved a settlement in 2013 that requires a performance metric to be developed by Commonwealth Edison to track time to connect DERs to the grid.[45] 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.[46] These are report-only metrics with no corresponding incentives or penalties.

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 NY-PSC, 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. Specifically, the NY-PSC found:[47]

[42] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, pp. 53, 63–69.

[43] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 89.

[44] Before 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 (i.e., 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 higher ramping requirements and lower capacity factors for thermal power plants balancing renewable loads, both of which would negatively impact thermal unit heat rates. To address this disincentive for renewable integration, a "deadband" of +/- 50 Btu/kWh sales was added to the heat rate target. A deadband is a zone of no adjustment around a specific performance criteria or metric; in this case, the deadband is expressed as a metric 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 deadband thus provides a range where utility revenue is not affected by variation in the metric. Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 94.

[45] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 85.

[46] Whited, M., Woolf, T., and Napoleon, A. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 85.

[47] NY-PSC. 2017 (March 9). Case 14-M-0101. Order Directing Modifications to the Joint Utilities Proposed Interconnection Earning Adjustment Mechanism Framework. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

- The survey metric will use survey results of DG applicants with projects greater than 50 kW and up to 5 MW.[48] 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 the process 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, web-based, or both. 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, which will be 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.

Consolidated Edison (Con Edison) received approval for an interconnection EAM in January 2017 as part of a rate case.[49] The interconnection EAM covers DG projects between 50 kW and 5 MW, and it measures results against three targets:

- Standardized interconnection requirements 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[50] to seek agreement on the targets for the three EAM measures and other details. Although targets will be established and data will be collected in 2017, there will be no earning opportunity for Rate Year One. The earning opportunity for Rate Year Two and Rate Year Three will be five basis points (0.05% of ROE; Con Edison's ROE is 9%) in each rate year.

The NY-PSC also has a separate EAM specifically for DER deployments.

3.2.6 Operational Incentives: Differing Approaches to Achieving System Efficiency

Operational metrics can and often do focus on achieving system efficiencies. 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.

3.2.6.1 Denmark

The Danish transmission system operator, 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

[48] The NY-PSC declined to apply an EAM to applications for projects less than 50 kW.

[49] NY-PSC 2017 (January 25). Case 16-E-0060, Case 16-G-0061, Case 16-E-0196. Order Approving Electric and Gas Rate Plans (for Con Edison).

[50] A collaborative is a stakeholder process that seeks input on various aspects of commission proceedings. They have historically been used in energy efficiency. For more information, see Li, M., and Bryson, J. 2015. *Energy Efficiency Collaboratives*. State and Local Energy Efficiency Action Network. https://www4.eere.energy.gov/seeaction/system/files/documents/EECollaboratives-0925final.pdf

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% 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' 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.[51] 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.

3.2.6.2 New York, United States

A recent NY REV Order mandates EAMs related to peak reduction and load improvement factor by which:

1. 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 based on a benefit-cost analysis 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 EVs, geothermal heat pumps, or other efficient and beneficial uses.
2. 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, NY-PSC will examine the contribution of each component of the program, to avoid any incentive to achieve by reducing economic activity. This EAM is still under development.

New York is attempting to achieve a more efficient utility 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 used 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.[52] This EAM includes three metrics:

- **Incremental System Peak Reduction:** Targets have already been set for this metric.

[51] 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, in order to lift efficiency to that of the top 10% of DSOs within four years.

[52] NY-PSC. 2017 (January 25). Case 16-E-0060, Case 16-G-0061, Case 16-E-0196. Order Approving Electric and Gas Rate Plans (for Con Edison).

- **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, combined heat and power, 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 four basis points, which is 0.04% of ROE, which would be added to Con Edison's ROE of 9%.

In January 2017, the NY-PSC approved a rate case for Con Edison that included several EAMs, including two energy efficiency metrics.[53] The first energy efficiency metric is for meeting or exceeding target levels for incremental gigawatt-hour savings. Energy efficiency incentives are not a new application of PBR. However, the second metric, developed through a collaborative process, is an energy intensity metric for both the residential and commercial sectors. It 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 in 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.[54] Con Edison can earn a maximum of 7.76 basis points in Rate Year One under this mechanism.

3.2.6.3 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,[55] which mandated performance metrics be adopted as part of the IRP process.[56] 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."[57] 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 PREC has now established a separate proceeding to revisit and revise those metrics.[58]

On November 15, 2016, the PREC issued a notice of investigation that commenced the process to review performance metrics more comprehensively. The PREC has already received comments from interested stakeholders.[59] The process will incorporate three separate components: (1) a PREC investigation into PREPA's operations to assist in developing final performance metrics that will supersede the metrics set forth in the IRP rules,

[53] Ibid.

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

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

[56] Act 57, §6C(h)(iv). Specifically, the law sets out detailed parameters that include revenue per 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.

[57] Act 57, §6C(h)(iv)., Statement of Motives.

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

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

Table 2. Draft Performance Metrics by Area[a]

Area	Metric	Unit of Measure	Target
Overall system	CAIDI (customer average interruption duration index)	Minutes	146
Generation	Plant availability (system)	Percentage	76%
Transmission and distribution (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%

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

(2) 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 (3) rulemaking to create the new amended metrics. One of the challenges, however, is that PREPA is a state-owned entity, making assessment of rewards or penalties challenging.

A subsequent order seeking comment from PREPA and interested stakeholders was issued on April 27, 2017.[60] In it, performance metrics were identified and listed under the following categories: overall system, generation, transmission, and distribution, customer service, finance, planning, environmental, operations, information technology, human resources, legal, renewable energy, and demand-side management. Each category has an identified list of potential metrics for which the PREC is seeking comment before 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 energy usage, will also affect system efficiency. Because of the lack of accountability for PREPA before 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 PREC considers the best course of action. Table 2 presents draft performance metrics used in Puerto Rico.

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

3.2.7 Operational Efficiency: Financial Solvency Linked to Efficiency Improvement

Where state-owned enterprises have been operating inefficiently for years and they need financial support because costs exceed revenue, it is possible to link continued state support to improving the efficiency of operations. A PBR mechanism being implemented in India uses financial incentives to achieve dual objectives: (1) 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 or more 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 less than the actual cost of supply and delivery. As a result, for many decades, the state government-owned 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 unable to supply adequate power at affordable rates, which hampers quality of life and overall economic growth and development. Efforts toward 100% village electrification, "24/7" power supply, and ambitious clean energy targets are very unlikely to be achieved without financially solvent DISCOMs that can provide continuous power. Power outages also adversely affect nation-building initiatives that depend on facilities having reliable electricity. In addition, defaults on bank loans by financially distressed DISCOMs have the potential to seriously impact the banking sector and the economy at large.[61]

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

UDAY operates through four initiatives aimed at (1) improving operational efficiencies of DISCOMs, (2) reducing the cost of power, (3) reducing the interest cost of DISCOMs, and (4) enforcing financial discipline on DISCOMs through alignment with state finances. Operational efficiency improvements (e.g., compulsory smart metering, upgradation of transformers, meters, and other network infrastructure) and implementation of energy efficiency measures (e.g., efficient LED bulbs, agricultural pumps, fans, and air conditioners) aim to reduce the average aggregate technical and commercial (AT&C) loss from approximately 22% to 15% and eliminate the gap between the average revenue realized and the average cost of supply by 2018–2019.[62]

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

[62] AT&C losses refer to a combination of technical losses and commercial losses. Technical losses are unavoidable losses owing to flow of power in transmission and distribution (T&D) systems that are the result of network design, specifications of the equipment used in the network, and network operation parameters. Commercial losses are avoidable to some extent and arise because of operational loopholes. They are 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

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.[63] In return for the bailout, the DISCOMs have been given target dates (from 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 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 it will provide support for DISCOMs through its own schemes (e.g., rural electrification and network upgradation). 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 unclear whether the new tariffs do this, or whether they can be enforced on consumers.[64] Consequences for noncompliance are unclear.

Reductions in the cost of power are being achieved through measures such as increased supply of less-expensive domestic coal, sourcing coal from more efficient plants, coal price rationalization based on 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 by states, which is not counted in de jure borrowing. However, credit rating agencies and multilateral agencies are conscious of this de facto debt in their appraisals.

To date UDAY has been well received by the states that have signed up for it.[65] This is encouraging, as the states are key stakeholders to the success of UDAY. Figure 2 shows the quarterly rankings for state/DISCOM performance publicized on the UDAY national dashboard, which encourages state and DISCOM good performance.

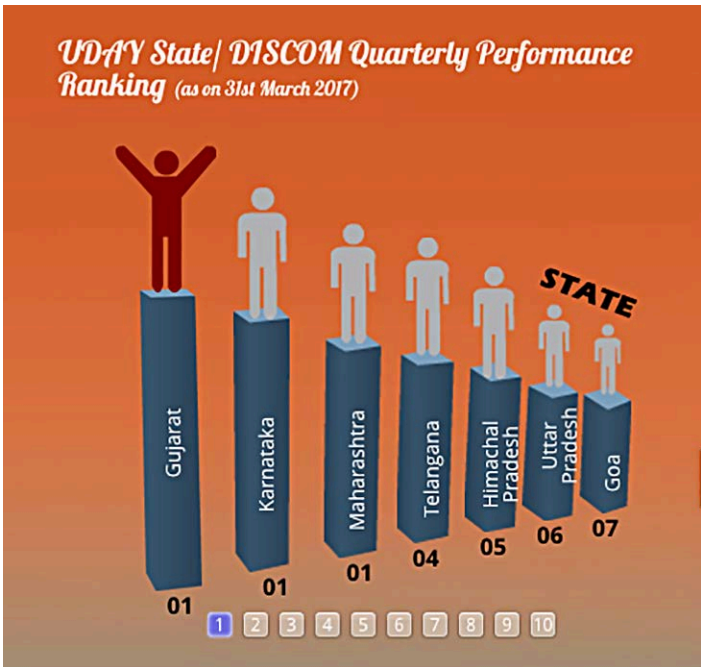

Figure 2. UDAY state/DISCOM quarterly performance ranking

Government of India, Ministry of Power. 2017. UDAY National Dashboard. https://www.uday.gov.in/home.php.

[63] 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% of the DISCOM debt will be addressed in one of two ways: conversion into lower interest rate loans by the lending banks or by issuance of DISCOM bonds backed by state government guarantee (which helps bring down interest rates). Madhu, M. 2016 (March 28). "All You Wanted to Know About UDAY." *The Hindu Business Line*. http://www.thehindubusinessline.com/opinion/all-you-wanted-to-know-about-uday/article8406121.ece

[64] Currently, 17 out of the 22 states have reported AT&C losses for this year, and the total losses across all 17 states are 22.49%. The goal is for each state to have 15% AT&C losses or less. Government of India, Ministry of Power. (undated). UDAY National Dashboard. https://www.uday.gov.in/atc_india.php. Additionally, tariff revisions were required as part of the memorandum of understanding 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 memoranda have been successful. Government of India, Ministry of Power. (undated). UDAY National Dashboard. https://www.uday.gov.in/atc_india.php.

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

3.2.8 Operational Metrics: Reliability

As part of a grid modernization initiative, the Illinois Commerce Commission adopted PBR formula rate tariffs.[66] These tariffs were approved under Illinois' 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 certainty about capital investments such as distribution reclosers, substation improvements, pole reinforcements, undergrounding targeted lines, and vegetation management.[67]

This Illinois tariff approved formula rates for participating utilities, thus providing greater utility confidence that grid modernization expenses would be found prudent with a set rate of return to be adjusted annually based on known factors. In exchange for this formula rate treatment, participating utilities are required to file multi-year metrics with the Illinois Commerce Commission to improve performance over a ten-year period, including reliability performance.

After installing grid automation and more intelligent sensors, and after making the range of approved grid hardening and smart grid investments described earlier, the utilities reported improvements in outage frequency and duration.[68] But the utilities have failed to meet the 75% improvement performance criteria set by the Illinois Commerce Commission and have been penalized with a five-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.[69] This is a negative incentive scheme that imposes a low penalty reduction in an approved formula rate when reliability criteria are 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 in their electric service do customers want to pay for? 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.[70]

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. They then used 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 that 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.[71]

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[66] Illinois Compiled Statutes. Infrastructure investment and modernization; regulatory reform. 220 ILCS 5/16-108.5. 2017.

[67] McCabe, A., Ghoshal, O. and Peters, B. 2016 (May). "A Formula for Grid Modernization?" *Public Utilities Fortnightly*. https://www.fortnightly.com/fortnightly/2016/05/formula-grid-modernization.

[68] Both utilities, Ameren and Commonwealth Edison, report reliability improvements. See Ameren Illinois. 2015 (June 1). *Modernization Action Plan*. https://www.icc.illinois.gov/downloads/public/edocket/406271.pdf; Commonwealth Edison. 2015 (April). *Multi-Year Performance Metrics*. https://www.icc.illinois.gov/downloads/public/edocket/402546.pdf.

[69] McCabe, A., Ghoshal, O., and Peters, B. 2016 (May). "A Formula for Grid Modernization?" *Public Utilities Fortnightly*. https://www.fortnightly.com/fortnightly/2016/05/formula-grid-modernization.

[70] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 41.

[71] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators*. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 35.

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

3.2.9 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 rate cases because of 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% 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 adapting 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 such clauses do indeed encourage operational efficiencies. One study concluded the modified fuel adjustment clauses resulted in 9% more output per given inputs than utilities with a 100% pass-through mechanism of all fuel costs.[72]

This experience with the incentive structure of fuel adjustment clauses and modifications is mentioned here because it demonstrates that 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 PBR must be iterated as new impacts are discovered. One such unintended consequence was a penalty for fuel-units that ramped up and 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.

3.2.10 Performance-Based Regulatory Approaches to Promote Customer Empowerment

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

Under the United Kingdom's Revenue = Incentives + Innovation + Outputs (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 can see the satisfaction rankings and, based on these rankings or their own personal experience, are able to switch suppliers.[73] Figure 3 shows the customer satisfaction ranking.

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, is reported in the DERA annual report to share the efficiency findings

[72] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

[73] Osborne, H. 2017 (February 27). "Energy Bills: Are UK Customers Finally Starting to Switch Supplier?" *The Guardian.* https://www.theguardian.com/money/2017/feb/27/energy-bills-more-uk-customers-are-moving-supplier-figures-show.

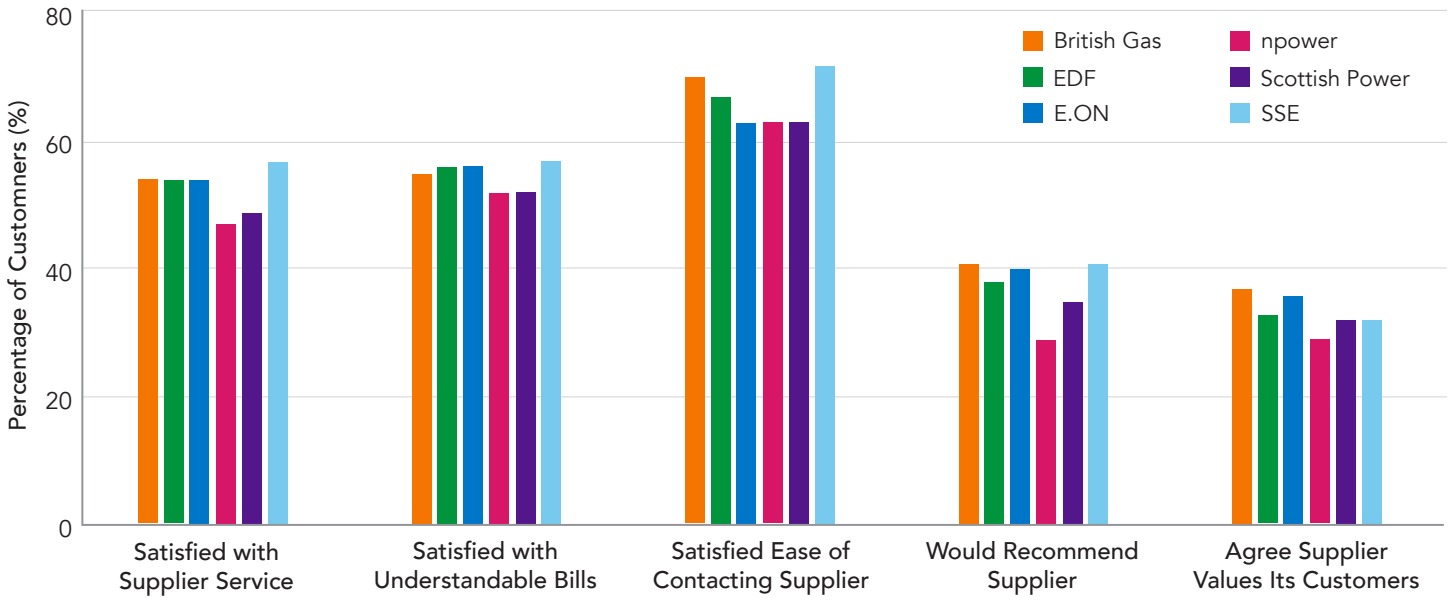

Figure 3. Customer satisfaction in the United Kingdom

Ofgem. 2016. "Customer Satisfaction: Six Large Electricity Suppliers." https://www.ofgem.gov.uk/chart/customer-satisfaction-six-large-electricity-suppliers.

with the public. In Denmark, as with many other EU member states, customers can switch their supplier (energy retailer) but cannot 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% of the DSO community. The Danish annual report is a less pronounced effort than RIIO's, but it is directionally similar in that it endeavors to provide utility performance data on compliance with regulatory benchmarking.[74]

Puerto Rico has included customer service 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:

- 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 on a survey of residential customers conducted by an independent entity with expertise in conducting customer surveys
- Business customer satisfaction, based on 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 PREC 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 PREC promulgated the metrics in Table 3 related to customer empowerment.

[74] The DERA annual report provides 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. The number of DSOs involved is one reason DERA may report on a DSO community basis.

[75] PREC. 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.

Table 3. Puerto Rico Metrics for Customer Empowerment

Metric	Description
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[75]

The relationships that the PREC perceives between customer satisfaction, efficiency, and system operations are 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 sector regulation. Taking a page from RIIO's 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, and performance criteria and metrics are likely to be settled in 2018. The NY-PSC ordered the parties of the NY 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 they are still 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.

3.2.11 PBR Approaches to Support Competition

Energy service companies, including DER providers, in partnership with new advanced technology companies, are offering services, including energy efficiency, distributed generation, smart energy management systems, and energy storage to small customers that were previously only available to larger customers. 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 anticompetitive utility behavior, certain metrics can encourage utility cooperation to deliver required services. These metrics include system interconnection application processing time and 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 (see Section 7.2.1). Care can also be taken to ensure incentives are evenhanded 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.[76]

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 anticompetitive behavior as well, if not addressed through other mechanisms such as those discussed here.

3.2.12 Peak Load Reduction Enabled by Demand Response

Peak load reduction represents 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 peak among other goals for DER deployment addressed earlier. A third is as a peak reduction system efficiency measure, such as was pursued under NY REV (see Section 3.2.1.1).

A regulatory decision reached in Illinois in 2013 required Commonwealth Edison to develop a performance metric to reduce peak load through demand response. This involves load impact reductions measured in MW of peak load reduction from the summer peak owing to smart meter-enabled demand response programs administered by the utility.[77] Although these performance metrics do not include any rewards or penalties, they provide valuable information for regulators and stakeholders to monitor whether customers are receiving the full benefit of the multi-billion-dollar smart grid infrastructure investment. In addition, these metrics provide valuable information going forward for regulators if it is determined that a financial reward or penalty is warranted.[78]

3.2.13 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.[79]

[76] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 72.

[77] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, pp. 85–86.

[78] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, pp. 85–86.

[79] It is fairly common for electricity to be priced by peak-hours/intervals where there are wholesale markets for electricity, but pricing utility T&D 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.

For example, a regulatory decision reached in Illinois in 2013 requires Commonwealth Edison to develop at least four performance metrics to track customers enrolled in time-varying rates:[80]

1. Number of residential customers 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 who have requested monthly data interchange for interval data (meaning the customer's 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. The same metric as the first metric but for small commercial customers.
4. The same metric as the second metric but for small commercial customers.[81]

The Illinois reporting metrics illustrate significant interest from Illinois in ensuring 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.[82]

3.2.14 PBRs for Smart Meter Deployment[83]

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 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 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% of all meters. 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 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 1, 2015 and December 31, 2021 (excluding those used for experimental pilots and standard electronic meters). The bonus is awarded throughout the asset lifetime. It is composed of two parts:

- Part 1 (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 2 (100 basis points) is calculated based 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:

1. Control investment costs.
   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%, no further costs are remunerated (i.e., no bonus and no base-rate remuneration).

[80] Puerto Rico is also looking at reporting metrics of time-of-use rates.

[81] Whited, M., Woolf, T., and Napoleon, A.. 2015. *Utility Performance Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 85.

[82] PREC. 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.

[83] Information in this section is from Commission de régulation de l'énergie. 2014 (July 17). Decision Determining the Incentive-based Regulatory Framework for ERDF's Smart Metering System for LV ≤36 kVA (English translation). http://www.cre.fr/en/documents/deliberations/decision/smart-metering-system.

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).

2. Comply with the deployment timetable.

   This incentive focuses 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, penalties are generated.

   To ensure that complying with the deployment timetable does not jeopardize the quality of the installation, the Commission de regulation de l'energie 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.

3. Guarantee the performance level expected from the Linky metering system.

   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 Commission de regulation de l'energie 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 Commission de regulation de l'energie 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 for the following:

- Percentage of successful remote meter readings by day
- Percentage of actual monthly readings published by Ginko[4]
- Percentage availability of customer internet portal
- Percentage of Linky meters with no remotely read figures for the last two months
- Percentage of remote services carried out on the day suppliers requested them
- 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 timescales:

- 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) 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 Commission de regulation de l'energie will ensure 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 and system administration).

4 Conclusions

As the previous examples and text demonstrate, PBR and PIMs have great value for the electric industry in a wide variety of ways and can be applied to many different situations. However, how exactly PBR mechanisms are most effectively enacted will vary greatly depending on the utility ownership model, institutional arrangements, and a variety of other local factors.

In many jurisdictions, conventional generation companies are worried that they are losing market share or that they will be unable to pay capital costs of current assets. So, what form of incentive regulation would be required for generation owners, and which generation owners are necessary to operate a modern grid? Some sort of incentive may be necessary to ensure certain generation is available for services, such as ramping to accommodate higher renewable penetrations. Transmission companies may need incentives to build bulk transmission where necessary, while ensuring their costs will be recouped despite shifts between distributed and central station generation. Distribution companies need incentives to connect all DERs while not losing money from decreased sales volume and revenue. What PBR mechanisms are best for distribution companies? In restructured markets of the 21st century, the 20th century rules of separation and codes of conduct require attention and become more important than ever to align incentives properly and to avoid hidden incentives.

These power sector dynamics and concerns occur as electric utilities are embedded in an increasingly sophisticated technological society. The power sector often represents progress in developing countries. In all cases, electricity enables achievement of important societal goals. Performance-based regulation is regulation in which anyone can know how the utilities are delivering on clearly stated expectations and, in its higher forms, where management is strongly motivated to deliver on public goals as well as internal and fiduciary goals.

Interest in PBRs is getting stronger. France just announced a new smart-grid-related PBR scheme. In the United States, the Rhode Island Public Utilities Commission and the Michigan Public Service Commission have plans to engage stakeholders to consider PBR. In Minnesota, the e21 Initiative brought many stakeholders together around PBR for the consideration of regulators. Both India and China are trying innovative new ways to use PBRs to drive change in state-owned entities.

A PBR in the form of cost-cap regulation is proven in multiple jurisdictions to provide cost containment incentives to utilities. However, there are also examples of poorly designed PBR mechanisms providing debatable benefits. Building on successes and failures of more than two decades of PBR development, leading jurisdictions are now moving to adopt incentives focused on pursuing goals as disparate as peak reductions, power plant efficiency, DER integration and interconnection to financial solvency, and smart meter deployments.

As jurisdictions take new approaches and gain experience, refined and successful PBR approaches will continue to emerge. For jurisdictions adopting and implementing PBRs, assessing the incentive level that is enough to make a difference in the approach of management—and no more than is necessary to optimize system, consumer, or societal benefits with room for imprecision—can be challenging. Even with no controversy about the guiding and directional incentives, getting the incentive level right takes time through trial and error, and perhaps starts with tracking performance with no incentive to gain experience with reporting and metric tracking initially. Particularly with innovative approaches and new performance criteria and metrics, examining new metrics to assess whether they work and whether they measure the value intended is a gradual and smart approach to getting the goals, incentives, performance criteria, and metrics calibrated to reflect the value a PBR scheme is intended to achieve. PBR approaches can then be evaluated, refined, and improved to further improve on value creation.

With the performance of regulation becoming more multifaceted—and given the growth of technology and other diverse public policy considerations—the avenues to more explicitly assess utility performance and to support innovation are increasing across multiple jurisdictions.

It is important through this process to distill a narrative about how all customers benefit if a utility receives an incentive for performance. This may involve describing how customers benefit or are supported by this system. It may also include elucidating the value to stakeholders of augmenting regulatory approaches to reward utility behavior rather than the traditional cost-of-service model.

Next-generation PBR may be a part of the answer to a larger question: What is the role of the next-generation utility? Although it is possible to focus on just retooling regulation to better reflect performance, a more fundamental experience may be to reconsider the proper roles for a monopoly utility, including traditional roles such as generation and delivery, of course, but also roles associated with "platform services"—as described in the NY REV process—or distribution system operator services.[84] Just as new technologies confound traditional resource categories and capabilities, the business model utilities have used for more than a century will evolve to reflect these changing realities and challenges.

[84] Bade, G. 2015 (January 28). "6 Thought Leaders on the Future of Utility Business Models and Regulation." *Utility Dive*. http://www.utilitydive.com/news/6-thought-leaders-on-the-future-of-utility-business-models-regulation/357635/.

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