

PERFORMANCE-BASED REGULATION IN A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

Mark Newton Lowry, Pacific Economics Group Research

Tim Woolf, Synapse Energy Economics

Project Manager and Technical Editor:

Lisa Schwartz, Lawrence Berkeley National Laboratory

About the Authors

Mark Newton Lowry is President of Pacific Economics Group Research LLC. He has been active in performance-based regulatory issues since the 1990s, with specialties including multi-year rate plans, productivity, benchmarking and revenue decoupling. A former Pennsylvania State University energy economics professor, he holds a Ph.D. in applied economics from the University of Wisconsin.

Tim Woolf is Vice President of Synapse Energy Economics. He has 30 years of experience with utility planning and regulation, specializing in demand-side management, integrated resource planning, performance-based ratemaking and decoupling. He was a commissioner at the Massachusetts Department of Public Utilities from 2007 to 2011. He holds a Master's in Business Administration from Boston University and a Bachelor of Science in Mechanical Engineering from Tufts University.

The authors were assisted by Melissa Whited of Synapse Energy Economics and Matthew Makos of Pacific Economics Group Research.

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Table of Contents

Foreword by U.S. Department of Energy.....	v
Glossary of Terms.....	vi
Executive Summary.....	1
1. Introduction	7
2. Ratemaking Tools for a High DER Future	9
2.1. Ratemaking Elements.....	9
2.2. Cost of Service Regulation	10
2.3. Revenue Regulation	15
2.4. Performance Incentive Mechanisms.....	18
2.5. Multi-Year Rate Plans.....	24
2.6. British RIIO System as an Example of Comprehensive PBR	31
3. Regulatory Considerations Regarding PBR	36
4. Criteria for Evaluating PBR	38
5. Perspectives on PBR Issues	40
5.1. Multi-Year Rate Plans.....	41
5.2. Performance Incentive Mechanisms.....	47
5.3. Multi-Year Rate Plans Versus Stand-Alone PIMs	53
5.4. What Can the United States Learn From the British Approach to PBR?.....	57
6. A Roadmap for Regulators	62
References	64



Table of Figures

Figure 1. Components of Performance Incentive Mechanisms.....	20
Figure 2. Distribution Productivity Trends of Central Maine Power and Two Peer Groups.....	31

Table of Tables

Table ES 1. PBR Elements.....	2
Table ES 2. Regulatory Options to Fit Different Contexts and Meet Different Goals.....	6
Table 1. Ratemaking Elements and PBR	9
Table 2. Traditional Performance Areas	21
Table 3. Emerging Performance Areas.....	21
Table 4. Examples of Potential DER-Related Performance Metrics.....	24
Table 5. Multi-Year Rate Plans From the Customers' Perspective	45
Table 6. Multi-Year Rate Plans From the Utility's Perspective	47
Table 7. Performance Incentive Mechanisms From the Customers' Perspective	51
Table 8. Performance Incentive Mechanisms From the Utility's Perspective	53
Table 9. Stand-Alone PIMs Versus MRPs From the Customers' Perspective	56
Table 10. Stand-Alone PIMs Versus MRPs From the Utility's Perspective	57
Table 11. RIIO Approach From the Customers' Perspective.....	60
Table 12. RIIO Approach From the Utility's Perspective.....	61
Table 13. Regulatory Options to Fit Different Contexts and Meet Different Goals.....	62



Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in scale to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity on implications are common to both time periods. The U.S. Department of Energy (DOE) played a useful role during the 1990s' discussion and debate by sponsoring a series of papers that illuminated and dug deeper on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues, with the aim to better inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of new and improved technologies, together with changing customer and societal desires and needs, both of which are coupled with possible structural changes in the electric industry and related changes in business organization and regulation. Some of the technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some of the technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To maintain effectiveness in providing reliable and affordable electricity and its services to the nation, power sector regulatory approaches may require reconsideration. Historically, major changes in the electricity industry came with changes in regulation at the local, state or federal levels.

The DOE, through its Office of Electricity Delivery and Energy Reliability's Electricity Policy Technical Assistance Program, is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, work closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.



Glossary of Terms

Attrition Relief Mechanism (ARM): A common component of multi-year rate plans that automatically adjusts rates or revenues between rate cases to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable cost drivers such as inflation and customer growth.

Authorized Return on Equity (ROE): The rate of return allowed by a state regulatory commission for the shareholders of an investor-owned utility, expressed as a percentage of the value of equity capital invested.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital. Base rates generally do not compensate utilities for large, volatile costs such as those for fuel and purchased power, which are often tracked.

Capex: Capital expenditures.

Cost of Service Regulation (COSR): The traditional North American approach to utility regulation that resets rates in occasional rate cases to recover the cost of its service that regulators deem prudent.

Cost Tracker: A mechanism providing expedited recovery of targeted costs. A tracker is an account of allowances for costs that are eligible for recovery. These allowances are then typically recovered via rate riders.

Distributed Energy Resources (DERs): Technologies, services and practices that can improve efficiency or generate, manage or store energy on the customer side of the meter. DERs can include energy efficiency, demand response, distributed generation, energy management systems, batteries and more. Plug-in electric vehicles are considered as part of distributed storage. DERs can be implemented by utilities, customers, third-party vendors or combinations thereof.

Earnings Sharing Mechanisms (ESMs): These share surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity (ROE) deviates significantly from its public utility commission-approved target. ESMs often have "deadbands" (neutral zones around the target) in which earnings variances are not shared with customers.

Efficiency Carry-over Mechanisms: These mechanisms allow for a share of lasting performance gains or losses to be kept by the utility when a multi-year rate plan expires.

Incentive-Compatible Menu: An incentive-compatible menu of regulatory contracts involves different combinations of key ratemaking elements, such as revenue and earnings sharing factors. These can be designed so that the utility, by its choice, reveals the attainable level of cost in a multi-year rate plan, thereby reducing information asymmetry.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for estimated revenue lost from specific causes such as utility demand-side management programs and distributed generation. An LRAM requires estimates of load impacts.

Marketing Flexibility: Some regulators have deemed it appropriate to provide utilities with greater flexibility to fashion rates and other terms of service in selected markets, typically via light-handed



regulation of rates and services with certain attributes. A traditional goal of such flexibility is to retain large-load customers and attract new customers to the utility system. These loads can spread fixed costs and stimulate local economies. Marketing flexibility can also be used to offer customers custom green power packages and value-added services that rely on new technologies. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to protect competitors and prevent cross-subsidization.

Multi-Year Rate Plans (MRPs): A common approach to performance-based regulation that features a multi-year rate case moratorium, an attrition relief mechanism and several performance incentive mechanisms.

Off-Ramp Mechanisms: These mechanisms permit suspension or reconsideration of a multi-year rate plan under pre-specified conditions (e.g., persistent, extreme under- or over-earning).

Ofgem: British Office of Gas and Electricity Markets, the regulator of gas and electric utilities in the United Kingdom.

Opex: Operation and maintenance expenses such as those for labor, materials, services, generation fuel and power.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): Metrics, targets and financial incentives (rewards, penalties or both) designed to strengthen performance incentives in targeted areas such as service quality and distributed energy resources.

Rate Base: The net (depreciated) value of utility investment used to provide service, including working capital.

Rate Case: A proceeding, usually before a state regulatory commission, to reset rates that involves a review of the utility's cost and the resetting of rates to recover the revenue requirement. These proceedings may also consider other issues such as rate designs.

Rate Case Moratorium: A set period of time between rate cases designed to reduce regulatory cost and strengthen utility performance incentives. Electricity prices (or revenues) are generally capped during this period, with the exception of cost trackers.

Rate Riders: An explicit mechanism on utility tariff sheets for supplemental revenue adjustments.

Revenue Requirement: The annual revenue that the utility is entitled to collect. The amount is periodically recalculated in rate cases and may be escalated by other mechanisms (e.g., cost trackers and ARMs) between rate cases. It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base less other operating revenues.

Revenue Regulation: By breaking the link between sales and revenue, revenue regulation reduces the incentive for a utility to increase sales between rate cases. Revenue regulation provides the utility with an allowed level of revenues each year, regardless of customer demand and energy use on the utility



system. Rates are adjusted to ensure the utility collects no more, and no less, than its allowed revenues. This is sometimes referred to as “revenue decoupling.” Revenue regulation does not include lost revenue adjustment mechanisms or straight fixed-variable rate design.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO is an innovative form of MRP that includes a relatively long rate-case moratorium of eight years, a forecast-based attrition relief mechanism, and an innovative set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on utility operations to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

Stranded Costs: Fixed or sunk costs that have become uneconomic due to changes in business conditions such as technology, demand, input prices or policies.

Test Year: A specific period used to calculate a utility’s rates. Some states use a historical test year and adjust billing determinants, opex, and rate base cost for known and measureable changes. Other states use a fully forecasted test year that considers other possible changes.

Throughput Incentive: Under traditional regulation, utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility, because the marginal cost of providing additional service is typically well below the rate per unit of use.

Totex: Under RIIO, capital expenditures and operating expenditures are combined into one category: “total expenditures,” or “totex” when setting the revenue requirement. The utility earns a return on a pre-determined portion of totex, regardless of whether the utility’s capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

Used and Useful: A regulatory concept used to determine whether investments may be included in rate base. While state laws vary, generally “used” means that the facility is actually operated to provide service, and “useful” means that without the facility, service would either be more expensive or less reliable.

X-Factor (aka Productivity Factor): A term in an index-based ARM formula that typically reflects the impact of productivity growth on cost growth.



Executive Summary

Performance-based regulation (PBR) of utilities has emerged as an important ratemaking option in the last 25 years. It has been implemented in numerous jurisdictions across the United States and is common in many other advanced industrialized countries. PBR's appeal lies chiefly in its ability to strengthen utility performance incentives relative to traditional cost-of-service regulation (COSR). Some forms of PBR can streamline regulation and provide utilities with greater operating flexibility. Ideally, the benefits of better performance are shared by the utility and its customers.

The shortcomings of traditional COSR in providing electric utilities with incentives that are aligned with certain regulatory goals are becoming increasingly clear. In particular, COSR can provide strong incentives to increase electricity sales and utility rate base. Further, some parties express concern that traditional COSR does not provide utilities with appropriate financial incentives to address evolving industry challenges such as changing customer demands for electricity services, increased levels of distributed energy resources (DERs), and growing pressure to mitigate carbon dioxide emissions. In addition, attention to potential new regulatory models to support the "utility of the future" has renewed interest in PBR.

This report describes key elements of PBR and explains some of the advantages and disadvantages of various PBR options. We present pertinent issues from the perspectives of utilities and customers. In practice, these different perspectives are not diametrically opposed. Nonetheless, this framework is useful for illustrating how various aspects of PBR may be viewed by those key groups. Regulators have a unique perspective, in that they must balance consumer, utility, and other interests with the goal of achieving a result that is in the overall public interest.

PBR Includes Many Elements and Variations

PBR is not a one-size-fits-all construct designed uniformly wherever it is applied. Instead, PBR is made up of several elements intended to strengthen utility performance incentives that can be applied in different ways and in different combinations. Some of these elements are applied as stand-alone elements in regulatory systems that are largely traditional.

The most common approach to PBR worldwide is the multi-year rate plan (MRP), which combines a rate case moratorium with an attrition relief mechanism (ARM) and some performance incentive mechanisms (PIMs). MRPs may also feature revenue regulation (also called revenue decoupling), earnings sharing mechanisms and other techniques. These elements are briefly described in Table ES 1.

MRPs can strengthen incentives for utilities to improve performance in a wide range of initiatives, and the benefits ideally are shared between utilities and their customers. If designed well, MRPs can provide strong incentives for utilities to support or implement DERs.



Table ES 1. PBR Elements

<p>Revenue Regulation</p>	<p>Revenue regulation (revenue decoupling) eliminates the throughput incentive by ensuring the utility recovery of allowed revenue regardless of megawatt-hours (MWh) and megawatts (MW) of utility system use. Allowed revenue is typically escalated using a predetermined formula. Under this approach, the impact on utility revenues between rate cases from energy efficiency, demand response programs, and customer-sited distributed generation can be reduced or eliminated.</p>
<p>Performance Incentive Mechanisms (PIMs)</p>	<p>PIMs consist of performance metrics, targets and financial incentives. PIMs have been employed for many years to address performance in areas such as reliability, safety and energy efficiency. In recent years, PIMs have received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and the implementation of new technologies and practices.</p>
<p>Multi-Year Rate Plans (MRPs)</p>	<p>MRPs permit utilities to operate for several years without a general rate case. The rate case moratorium typically lasts four to five years. Between rate cases, an attrition relief mechanism (ARM) automatically adjusts rates or the revenue requirement according to the predetermined formula that compensates a utility for cost pressures without tracking its actual cost. ARMs are commonly based on cost forecasts, indexed trends in utility costs, or a combination of the two. MRPs generally also include PIMs and may include revenue regulation and cost trackers.</p>
<p>RIIO (“Revenue = incentives + innovation + outputs”)</p>	<p>RIIO is the PBR approach used in Great Britain, where MRPs have been used to regulate utilities for more than 25 years. RIIO is the latest MRP system for energy utility regulation. Key elements of the RIIO approach include an eight-year plan term, revenue regulation, a forecast-based revenue cap escalator, and innovative use of PIMs. RIIO is often cited as a potential model for regulating the “utility of the future.”</p>

Key Advantages and Disadvantages of Multi-Year Rate Plans

Customers’ Perspective

MRPs can strengthen incentives for utilities to improve performance in a wide range of initiatives, and the benefits ideally are shared between utilities and their customers. If designed well, MRPs can provide strong incentives for utilities to support or implement DERs. MRPs can also provide utilities with additional marketing flexibility where regulators deem this desirable, while providing some protection for customers taking service under standard tariffs. MRPs can also reduce regulatory cost.

However, some regulators and consumer advocates may lack the expertise and funding needed to effectively consider the implications of MRPs and to address design issues. A utility’s revenue may exceed its costs for extended periods. When regulators introduce tools to contain these variances, such as earnings sharing mechanisms, utility performance incentives may be weakened.

Utility’s Perspective

MRPs give utilities more opportunities to profit from improved performance. They can provide utilities with greater marketing flexibility to meet competitive challenges, retain large load customers, and satisfy the complex, changing demands of customers. Improved performance can become a new profit center for a utility at a time when traditional opportunities for earnings growth are diminishing. Less frequent rate cases can help utility managers focus on their basic business of providing customer-responsive services cost-effectively. Reduced regulatory cost is particularly valued by utility companies that operate in multiple jurisdictions.



On the other hand, MRPs can increase operating risk, without providing the utility with a compensatory adjustment to the authorized return on equity. Revenue may occasionally fall short of cost. Further, rate plans can be designed in such a way that customers receive most benefits, leaving the utility at a disadvantage.

Key Advantages and Disadvantages of Performance Incentive Mechanisms

Customers' Perspective

PIMs allow regulators and stakeholders to provide detailed guidance to utilities with regard to specific performance areas and the desired outcomes. They can be offered incrementally and gradually, thereby reducing customer risk.

This detailed guidance can also create tension among the parties involved. If there are significant incentives at stake, proceedings to design and approve PIMs can be complex, contentious and resource intensive. In practice, PIMs tend to focus on performance areas that are relatively easy to identify and evaluate, such as service quality, reliability and demand-side management (DSM) implementation, but may overlook other performance areas that also require improvement.

If not well-designed, PIMs can suffer from several pitfalls that would be detrimental to customers, such as disproportionate rewards, lax standards or unintended consequences.

If not well-designed, PIMs can suffer from several pitfalls that would be detrimental to customers, such as disproportionate rewards, lax standards or unintended consequences. Financial rewards and penalties need to strike the right balance: low enough to mitigate regulatory risk, but strong enough to incentivize correct utility behavior. This balance can sometimes be difficult to achieve.

Utility's Perspective

PIMs alert utility managers to special concerns of regulators and customers, helping to maintain good relationships among the parties to regulation. PIMs, like MRPs, can provide new earnings opportunities in an era when traditional opportunities are diminishing for some utilities.

But chosen metrics are sometimes difficult to control. Targets can be unreasonable at the outset or ratcheted unfairly as performance improves. Many PIMs involve penalties but no rewards, which is counter to the workings of competitive markets, where good performance typically results in higher revenue. When PIMs do offer rewards, they are often relatively small due to low reward rates and the limited scope of PIMs.

Are Stand-Alone PIMs Better Than Multi-Year Rate Plans?

The recent resurgence of interest in PBR in the United States has often focused on the addition of stand-alone PIMs to existing regulatory systems, rather than implementing MRPs or refining MRPs when they are already in use. This report discusses the advantages and disadvantages of MRPs and stand-alone PIMs.

Customers' Perspective

Relative to MRPs, PIMs tend to be simpler, more transparent, less risky, and more focused on specific performance areas of interest to regulators. While the design of PIMs is also subject to some



Relative to MRPs, PIMs tend to be simpler, more transparent, less risky, and more focused on specific performance areas of interest to regulators.

controversy and complexities, the stakes are generally much lower than in MRP design, and the process may be less contentious. On the other hand, stand-alone PIMs have to provide sizable incentives if they are to induce utilities to fully embrace energy efficiency and other DERs wherever they are preferable to utility capital expenditure. Important areas of utility performance such as general cost containment could in principle be addressed by PIMs, but typically are not.

MRPs incentivize a broader array of performance improvement initiatives. A well-designed MRP with revenue regulation and appropriate PIMs for DERs may be the most effective way to promote DERs. MRPs may also reduce the frequency of general rate cases and can therefore substantially reduce regulatory cost, unlike stand-alone PIMs.

Utility's Perspective

Stand-alone PIMs can make more sense for utilities when the current regulatory system yields adequate revenue, investment opportunities are ample, and regulators and stakeholders are resistant to the types of sweeping changes associated with MRPs. It is sometimes difficult for the utility and stakeholders to agree on compensatory revenue escalation in an ARM.

MRPs make more sense for utilities when the regulatory community is receptive and containing regulatory cost is a special concern due, for example, to ownership of multiple utilities. In some cases, it is relatively easy for the utility and stakeholders to agree on a set of revenue escalation provisions.

MRPs can increase utility marketing flexibility by allowing a utility to provide alternative prices and products to some customers without a rate case and without affecting customers in other rate classes. The need for flexibility may increase in coming years in order to: (a) contend with increased competition from distributed generation; (b) provide customers with tailored clean energy products; and (c) offer optional rates and new services that advanced metering infrastructure makes possible.

What Can the United States Learn From the British Approach to PBR?

Customers' Perspectives

The United Kingdom's RIIO approach to regulation has been mentioned in several recent papers as a promising new regulatory model for the "utility of the future." It offers numerous regulatory innovations. For example, converting multi-year cost forecasts into ARMs with inflation adjustments provides more inflation protection than the "stair-step" ARMs that are popular in the United States. Incentive-compatible menus have promise in the design of ARMs and other plan provisions. RIIO uses PIMs to creatively address new performance areas.

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies.



Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices. Regulators and stakeholders who wish to improve performance comprehensively and also wish to focus on some specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs.

Despite its innovation, RIIO is an unusually expensive and time-consuming approach to MRP design. Further, requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments. North American regulators have developed alternative approaches to MRP design that are also worth considering. These include ARMs based on indexes, PIMs for DSM, efficiency carry-over mechanisms, and the use of settlements to establish MRP terms.

Utility's Perspective

ARMs based on multi-year cost forecasts can help fund expected cost increases and sidestep controversial indexing and benchmarking research. Inflation adjustments reduce operating risk.

On the other hand, some utilities may resist the extensive use of independent benchmarking and engineering studies in the British approach to ARM design. Eight-year ARMs do not provide utilities with much flexibility for dealing with unforeseen challenges, even if they are based on a utility's own forecast.

A Roadmap for Regulators

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies. In general, discussions of PBR options in a high DER future should evaluate and balance the range of potential PIM and MRP options that might fit any one jurisdiction.

Table ES 2 presents a summary of how various PBR options might match different regulatory goals. The left column identifies the performance improvement goals a state might have; the middle column indicates the extent to which regulators and stakeholders are open to making regulatory changes; and the right column indicates the combination of PBR options that might be appropriate for that state.



Table ES 2. Regulatory Options to Fit Different Contexts and Meet Different Goals

Performance Improvement Goals	Openness to Regulatory Change	PBR Options
None	Low	Maintain current ratemaking practice
Improvement in specific areas	Low	Adopt PIMs for specific areas
General improvement in utility performance Streamlined regulation	Moderate to high	Adopt an MRP
Support for DERs	Low	Adopt PIMs for DER <i>or</i> revenue regulation
Support for DERs	Moderate	Adopt PIMs for DERs <i>and</i> revenue regulation
Support for DERs General improvement in utility performance Streamlined regulation	High	Adopt PIMs for DERs, an MRP and revenue regulation

Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices.

Regulators and stakeholders who would like to promote improvements in utility performance should consider what areas of performance are most in need of improvement and are most critical in a high DER future. If their main concern is to improve performance in specific areas, stand-alone PIMs might be sufficient to address these areas. If they instead seek wide-ranging performance improvements, including better capital cost management, MRPs may be better suited to these goals than PIMs alone.

Regulators and stakeholders who wish to improve performance comprehensively and also wish to focus on some specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs. For example, an MRP with revenue decoupling, tracker treatment of DER-related costs, and PIMs related to cost-effective DERs can provide strong encouragement for utilities to support cost-effective DERs.



1. Introduction

Performance-based regulation (PBR) of utilities has been implemented in numerous jurisdictions across the United States and is common in many other advanced industrialized countries. PBR can strengthen utility performance incentives relative to traditional cost-of-service regulation (COSR), reduce regulatory cost and provide utilities with greater operating flexibility. The end result can be better utility performance.

In a potential future where there is a high reliance on energy efficiency, peak load management, distributed generation, storage and other kinds of distributed energy resources (DERs), there may be an increased need for performance-based types of regulation, for several reasons:¹

- Under COSR, utilities generally have strong financial incentives to increase rate base and electricity sales. This creates a disincentive to utilize cost-effective DERs to reduce utility system use and avoid new capital investments. In a possible high DER future, there may be even greater need to mitigate utility financial disincentives to support cost-effective DERs.
- Technologies are changing, and the pace of such change may accelerate in a high DER future. To cope with technological developments, utilities must innovate, develop new planning practices, and be accorded increased operating flexibility.
- As technologies and systems evolve rapidly, a new generation of stranded costs and used-and-useful issues may arise. Utilities may need more regulatory guidance regarding whether and how to invest in rapidly evolving technologies. One of the many ways to provide such guidance is through the use of targeted performance incentive mechanisms (PIMs).
- New technologies also increase opportunities to offer customers new services in areas such as energy efficiency and demand response, installing and operating distributed generation resources, providing customer and other data necessary to support DERs, and providing access to third-party providers of DERs. In a high DER future, regulators may wish to encourage strong performance in supporting new types of customer services.
- In a high DER future, electric utilities will be under considerable pressure to keep costs as low as possible.² Well-designed and executed PBR mechanisms can provide incentives to strengthen utility performance and keep costs down.

This report addresses several questions regarding the role that PBR could play in a high DER future. In particular:

1. Does traditional COSR provide utilities with appropriate regulatory direction and incentives in a high DER future?

¹ During the transition to a high DER future, there may be instances where some utility infrastructure becomes obsolete prior to the end of its book life. In such cases, regulators will need to consider how to address ongoing cost recovery for prudently incurred investments, regardless of regulatory regime — COSR or PBR.

² See the first report in Berkeley Lab's Future Electric Utility Regulation series, by Corneli and Kihm (2015).



2. Can some form of PBR provide improved regulatory direction and incentives in a high DER future?
3. What are the alternative elements of PBR and the key ways of designing PBR mechanisms, and what are the implications of the different PBR approaches in a high DER future?
4. What are the key challenges and controversies with regard to PBR designs and practices?
5. What are the implications for utilities, regulators, customers, and the public interest of PBR designs and practices?

In Chapter 2 we provide a detailed description of COSR and various ratemaking elements of PBR. In Chapter 3 we discuss the issues that should be considered when evaluating PBR, and in Chapter 4 we describe criteria that can be used to evaluate whether and how to implement PBR. We discuss in Chapter 5 several key challenges and controversies regarding the implementation of PBR from different stakeholder perspectives. Chapter 6 draws some conclusions and provides a roadmap for regulators.



2. Ratemaking Tools for a High DER Future

2.1. Ratemaking Elements

PBR is essentially a package of ratemaking tools or elements that can be applied in different ways and in different combinations. Some of those elements are not unique to PBR; they are also sometimes added to largely traditional regulatory systems. To make matters more confusing, the industry uses a variety of terms to describe similar, or overlapping, regulatory approaches. For example, PBR around the world has chiefly taken the form of multi-year rate plans (MRPs) that include one or more performance incentive mechanisms. However, PBR could also take the form of a package of performance incentive mechanisms (PIMs) without an MRP.

Table 1 provides a summary of ratemaking elements for various regulatory constructs. The first column lists ratemaking elements that are frequently included in PBR mechanisms. The other columns include the different regulatory constructs relevant to our discussion, including Great Britain’s approach to PBR, referred to as “RIIO.”³ The following sections discuss each of these constructs at some length.

Table 1. Ratemaking Elements and PBR

Ratemaking Elements	COSR	Performance-Based Regulation		
		Stand-Alone PIMs ⁴	MRP	RIIO
Rate Case Moratorium	---	---	Yes	Yes
Attrition Relief Mechanism (ARM)				
Forecast-based ARM	---	---	Sometimes	Yes
Index-based ARM	---	---	Sometimes	---
Hybrid ARM	---	---	Sometimes	---
Marketing/Pricing Flexibility	Occasionally	---	Sometimes	---
Earnings Sharing Mechanisms	---	---	Sometimes	Yes
Efficiency Carry-over Mechanisms	---	---	Sometimes	---
Performance Incentive Mechanisms	---	Yes	Usually	Yes
Revenue Regulation (Decoupling)	Sometimes	Sometimes	Sometimes	Yes

³ Revenues = Incentives + Innovation + Outputs. See Section 2.6.

⁴ Adopting one or two PIMs should not be considered PBR, but adopting several PIMs in a more comprehensive way could be.



As indicated in Table 1, MRPs typically include most or all of the ratemaking elements related to PBR. Also, regulators often add PIMs, revenue regulation and cost trackers to COSR to provide utilities with specific incentives. However, each jurisdiction tends to implement MRPs differently, including or excluding particular elements to suit their particular needs.

2.2. Cost of Service Regulation

The approach used in the United States to regulate retail rates of investor-owned electric utilities has long been the subject of analysis and criticism. Regulators in other countries have been openly skeptical about the desirability of traditional COSR, and they have proven more willing than U.S. regulators to use PBR. Some recent U.S. commentaries have suggested that traditional regulation is ill-suited for regulating the electric “utility of the future” and have touted PBR as an alternative.⁵ This section of the report explains traditional regulation and considers some of its limitations.

COSR Explained

The general approach that state public utility commissions use to regulate retail rates of electric utilities developed over decades.⁶ This regulatory system is called “cost-of-service regulation” because rates for each utility are designed to recover the particular utility’s costs of providing service. We discuss here common features of COSR, noting that there are many variations on the theme in the United States.

The chief means of adjusting rates under COSR is the general rate case. In these litigated proceedings, the base “revenue requirement” is set equal to the normalized net cost of service in a test year. The cost of service is calculated as the sum of electric operation and maintenance expenses (opex), depreciation, taxes, and a return on the net (depreciated) value of utility investments (rate base). *Net cost* is calculated by subtracting any revenue the utility garners from sources other than tariffed retail electric services.⁷

In principle, the entire net cost of service can be subject to a prudence review in each rate case. Prudence reviews can be time-consuming and controversial since prudence can be difficult to assess, and the dollars at stake encourage parties to argue their positions energetically. Another frequent source of rate case controversy is the target rate of return on the equity component of rate base.

In contemporary COSR, regulators sometimes use cost trackers to address some utility costs more promptly than rate cases can achieve. A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that are deemed prudent by regulators. Recovery of these costs is then typically initiated promptly using tariff sheet provisions called “riders.”

⁵ See, for example, e21 Initiative (2014); Lehr and O’Boyle (2015); Fox-Penner, Harris and Hesmondhalgh (2013).

⁶ The Federal Energy Regulatory Commission (FERC) uses a substantially different system to regulate interstate power transmission. Formula rate plans (a kind of broad-based cost tracker) are common.

⁷ For both vertically integrated utilities and utility distribution companies, “other revenue” includes revenue from miscellaneous other products and services that are enabled using utility assets. An example is rental of land under transmission lines. For vertically integrated utilities, the largest source of other operating revenue is typically sales in bulk power markets.



Large, volatile costs like those for fuel and purchased power are traditionally collected through cost trackers. The components of rates that address the less volatile costs of non-energy inputs such as labor, materials and capital are sometimes called “base rates.”⁸

Trackers are also used sometimes to compensate utilities for costs that are rapidly rising and do not produce much counterbalancing revenue, whether or not they are volatile.⁹ Costs of accelerated capital expenditures are most commonly tracked on the basis of this rationale.

To establish rates, the revenue requirement must be allocated across the utility’s services. For each service, rates are then set to recover the assigned revenue requirement given assumed quantities of “billing determinants.” Most base rate revenue is typically drawn from usage charges, which vary with a customer’s use of the system,¹⁰ while the balance of revenue is typically drawn from fixed customer charges.

Utilities file rate cases with state public utility commissions when their net cost of service is expected to exceed revenue from tariffed retail services.¹¹ The timing of these cases is irregular and depends on business conditions. For example, rate cases are more frequent in a period of rapid inflation.

The frequency of rate cases for vertically integrated utilities versus restructured distribution utilities can differ. Because vertically integrated utilities own generation capacity, a higher share of their assets is needed to serve variable load. In an era of increasing reliance on DERs, the reduced need for utility-owned generation assets may reduce the need for rate cases. New capacity that is needed may be purchased in bulk power markets. Depreciation of older plants slows rate base growth, which also may reduce the need for rate cases.

Regulatory Issues

Regulatory Cost and Its Consequences

Regulatory cost is an important and underappreciated consideration in choosing a regulatory system. In the case of COSR, the overriding cost concern is general rate cases since the entire net cost of a utility must be reviewed and all rates must be reset.¹² Rate cases typically last six months or more and require considerable resources from utilities, regulators and other stakeholders. Expenses incurred in a rate case can easily reach into the millions of dollars. Regulators understandably seek ways to contain regulatory cost. The pressure to do so increases to the extent that rate cases are frequent, numerous utilities are regulated, and rate case issues are controversial.

A number of tools can help contain regulatory cost, but some traditional economy measures have undesirable side effects. Limiting the utility’s rate and service offerings, for instance, reduces the difficult chores of allocating the revenue requirement across services and considering the impact of

⁸ Base rate revenue is sometimes called “margin.”

⁹ Examples of operation and maintenance expenses that are sometimes tracked due in whole or part to their rapid growth include those for health care.

¹⁰ Volumetric and demand charges are the most common usage charges. Demand charges are based either on the customer’s peak hourly receipts during the billing month or year, or its receipts at coincident (system) peaks. For commercial and industrial customers, demand charges collect most base rate revenue. For residential customers, base rate revenue is typically drawn chiefly from volumetric charges.

¹¹ Rate cases are also occasionally compelled by the commission or instigated by other parties that claim overearning.

¹² Rate cases nonetheless have benefits, which include the opportunity to review utility operations and provide feedback.



utility offerings on market competition. These restrictions on marketing flexibility are undesirable to the extent that customers have diverse and rapidly changing needs for utility services. There is also a risk that customers will uneconomically bypass the utility's system, causing other customers to pay higher rates.

Another traditional measure for lowering regulatory cost is to limit detailed prudence reviews to issues that are especially controversial, such as sustained generating plant outages or poor responses to major storms. However, prudence reviews suffer from several shortcomings. Lower-profile but nonetheless important prudence issues may receive insufficient attention. Funding for commission staff and consumer groups to review prudence is often limited. Prudence reviews are based on financial penalties for poor performance, but do not allow for financial rewards for superior performance. In practice, a significant part of the cost of service receives little or no detailed review. For example, disallowances are rare for costs of replacing aging assets.

To reduce the frequency of general rate cases, regulators can use cost trackers to address volatile or rapidly rising costs that could otherwise trigger frequent general rate cases. Both of these economy measures can weaken utility performance incentives, including the incentive to contain rate-base growth, as we discuss below.

Incentive Issues

To understand COSR incentive issues, it may help to consider the performance incentives of firms in competitive markets. The market for corn is illustrative. Corn prices are sufficient to provide producers *as a group* with a competitive rate of return *in the long run*. Returns of equally efficient producers vary (due, for example, to differences in weather), and efficient producers may occasionally be unable to earn competitive returns (due, for example, to slack demand or supply gluts). Prices are completely insensitive to the cost of *individual* producers. Farmers thus keep all of the incremental, after-tax profit from their efforts to reduce their costs. This strengthens their cost containment incentives. Owning farmland or corn-producing and drying equipment is not a goal in itself, and many corn producers rent some of the acreage, equipment and storage capacity they use. Consumers benefit in the long run as industry productivity growth drives down the real price of corn. In a period of weak demand, the price of corn falls. This stabilizes consumption and compels producers to try all the harder to contain cost. Note also that prices vary with the quality of corn, so that farmers have an incentive to make sure that their corn complies with established quality standards.

The incentives embedded in such competitive markets differ from incentives embedded in COSR for electric utilities in two important respects. First, incentives to contain cost are weaker to the extent that a utility's revenue tracks its own cost closely; were its revenue to track its cost exactly, a utility could grow its earnings only by growing its rate base. The closeness with which cost tracks revenue under COSR is greater to the extent that rate cases are frequent and trackers address a large share of cost.¹³ Rate cases might happen more frequently when growing reliance on DERs causes use of the utility's system to grow more slowly than its capacity. COSR thus contains the seeds of a disequilibrium situation in which increasing competition from DERs weakens performance incentives, making utility service less attractive and thereby encouraging further inroads by competitors.

¹³ Trackers can be designed to strengthen cost containment incentives but typically are not.



Second, to the extent that a utility's rate of return exceeds the cost of capital, electric utilities have an incentive to make excessive capital investments. Under such conditions, capital spending becomes a goal in itself.

Regulators in other countries display much more concern with utility performance incentives than their American counterparts. For example, the Alberta Utility Commission discussed the incentive problem with traditional regulation in a letter announcing a generic proceeding to consider PBR for provincial energy distributors. These companies were filing frequent rate cases in a period of rapid regional economic growth.

This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources [...] These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing.¹⁴

This proceeding ended in a mandate for all Alberta energy distributors to operate under MRPs.

DERs pose special incentive issues under COSR. Consider first that all forms of DERs reduce revenue from usage charges. Since costs of non-energy inputs such as capital are largely fixed in the short run, increased reliance on DERs reduces utility earnings until base rates can be raised in the next rate case.¹⁵ This disincentive abates with more frequent rate cases.

A second incentive issue arises from the fact that DERs can reduce opportunities for utilities to grow rate base. The problem is greatest for assets, such as generation capacity and substations, the need for which is closely tied to load. The need for substations is especially sensitive to peak load, whereas the need for generation assets also depends on the volume of service.

The disincentive to facilitate DERs is offset to the degree that utilities can profit from slowing rate base growth. Under COSR, utilities benefit from slowing rate base growth only between rate cases. Any resulting reduction in the depreciated value of rate base in the test year for the next rate case is passed entirely to customers. For example, the portion of the revenue requirement corresponding to an aging distribution substation that has not been replaced due in whole or part to DERs is reset in the next rate

Rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources.

¹⁴ Alberta Utilities Commission (2010), pages 1–2.

¹⁵ The lost revenue problem is less pronounced for vertically integrated utilities, since a higher percentage of their base rate input costs are load related, and idle generating capacity can be used for profitable off-system sales.



case to its lower, more depreciated value. The incentive to contain rate base growth thus falls with the frequency of rate cases and the pervasiveness of trackers for load-related capex costs.¹⁶

Many other costs that are sensitive to DERs are recovered through cost trackers, and this also weakens incentives to embrace DER solutions. Most notable are the costs of fuel and purchased power.¹⁷ For example, energy efficiency programs provide an opportunity for a utility to reduce the cost of purchased power, but the utility has little to no incentive to reduce purchased power costs if they are simply passed through to customers in a cost tracker. The weak incentive of utilities to contain tracked fuel and purchased power expenses is quite important in an age when generation fleets burn large amounts of price-volatile natural gas, and a sizable share of the power requirements of most utilities is purchased rather than self-generated.

Utilities, like other firms, also do not profit from savings in many costs that their operations impose on others. Chief among these are “external” costs, like those from carbon and other emissions from fossil-fueled generation, which are not reflected in electricity prices in most regions of the United States. This further weakens utility incentives to embrace DER solutions.

Consider, finally, that DERs can affect service quality in positive and negative ways, but utility revenue is not as sensitive to the quality of service as revenue typically is in competitive markets. Thus, a utility is not automatically rewarded for improvements in reliability that might result from DERs. Revenue is also largely insensitive to the quality of connections and other special services provided to DER customers.

We conclude that utilities under traditional regulation have a material disincentive to accommodate DERs, even when DERs meet customer needs at lower cost than traditional grid service.¹⁸ In addition, utilities are largely indifferent to other potential benefits of DERs. The importance of utility disincentives for DERs is increasing in an era in which customers have mounting interest in DERs, and the electricity industry is increasingly reliant on DERs to reduce its environmental impacts.

Mandates Are Not Always Enough

Key aspects of utility behavior can and should be mandated. For example, regulators approve the designs of a utility’s retail rates. They can use this authority to ensure that rate designs send the right signals to customers regarding the cost of services that they might request. Generation plant additions are controlled through such means as integrated resource planning, certificates of public convenience and necessity, competitive bidding, renewable portfolio standards and prudence reviews. Measures like these may be more extensively used in the future to control distribution plant additions. Wherever regulators and other policymakers can effectively administer mandates, there is less need for incentives.

We conclude that utilities under traditional regulation have a material disincentive to accommodate DERs, even when DERs meet customer needs at lower cost than traditional grid service.

¹⁶ Capital cost trackers can be designed, however, to strengthen capex containment incentives.

¹⁷ Some utilities also have tracker treatment of transmission expenses.

¹⁸ Under COSR utilities are, in other words, incented to oppose efficient levels of DERs.



There are nonetheless several benefits to complementing mandates with strengthened utility incentives. The case of DERs is illustrative. Poorly incentivized utilities will not, for example, use their considerable influence to proactively promote cost-effective DERs, and may oppose such resources.

A poorly incentivized utility will also be less cooperative at implementing established policies. For example, utilities can stress the downside of DER options in integrated resource and distribution planning exercises. As another example, lengthy delays in processing distributed generation connection requests have produced long queues for distributed generation customers at some utilities.¹⁹ The burden of regulation is thereby increased.

COSR Refinements

Much as growth in the demand for electric vehicles has been slowed by continuing improvements in petroleum-fueled vehicles, the need for PBR can be mitigated by the continuing evolution of traditional regulation. For example, revenue decoupling can reduce the utility disincentive to embrace energy efficiency. More funds can be made available for the independent review of utility performance in rate cases and occasional audits and benchmarking studies. Cost trackers can be incentivized. Regulators can make more use of integrated resource planning and extend it to the distribution system.

2.3. Revenue Regulation

As described in Section 2.2, traditional COSR provides utilities with a financial incentive to increase sales and a corresponding disincentive to reduce sales. Under COSR, base electricity prices are fixed between rate cases, which means that utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility, because the marginal cost of providing additional service is typically well below the price of electricity. This effect is sometimes referred to as the “throughput incentive,” because utilities can increase revenues and profits by increasing the amount of electricity they deliver.

Revenue regulation is a modification to ratemaking designed to eliminate the throughput incentive by weakening or severing the link between utility sales and revenues.²⁰ Revenue regulation helps a utility recover its allowed level of revenues each year, regardless of electricity consumption.²¹ This is accomplished with the following steps:

- a) The utility’s revenue requirements for the test year are set in a general rate case, using the same practices and principles that are used under traditional cost-of-service ratemaking.
- b) A certain amount of “allowed revenues” are determined for the years following the test year. In theory, these allowed revenues could be held constant at the level of revenue requirements determined for the test year. In practice, the allowed revenues are typically adjusted each year to account for the expectation that utility system costs will change in the years between rate cases due, for example, to input price inflation and growth in the number of customers served.

¹⁹ Stanfield (2015a).

²⁰ Revenue regulation is frequently referred to as “decoupling.” We use the term “revenue regulation” throughout this report because it is more descriptive than “decoupling.”

²¹ For a more detailed discussion of revenue regulation, see Regulatory Assistance Project (2011).



- c) On a periodic basis between rate cases (e.g., each year), the utility’s revenues are reconciled to ensure that the actual revenues recovered equal the allowed revenues. This is often accomplished with a separate reconciling rate rider. In those periods where the utility’s actual revenues exceed the allowed revenues, customers will be refunded the difference, and vice versa.

In this way, actual revenue collected will track the allowed revenue more closely. Note that under this approach, the utility’s revenues will be unaffected by all factors that could increase or reduce sales, including energy efficiency and demand response programs administered by the utility and third parties, more stringent building codes and appliance efficiency standards, naturally occurring energy efficiency,²² new rate designs, increases in non-utility-owned distributed generation, the impacts of weather, and the impacts of the economy on customer consumption patterns. There is no need to estimate load impacts.

Revenue regulation is currently in place for electric utilities in 14 jurisdictions across the country²³ and is being actively considered in several other states.²⁴

Key Design Issues

Revenue regulation mechanisms can be designed in many different ways, with significant implications for utility cost recovery and for customers.²⁵ In our view, revenue regulation mechanisms should achieve three key goals: (1) eliminate the throughput incentive; (2) improve the alignment of utility revenues and costs; and (3) ensure that customers are protected and are in fact better off than they were prior to revenue regulation.

Revenue regulation mechanisms should include at least the following key provisions to help protect customers:

- The initial test year rates should be set in the course of a full rate case, applying traditional ratemaking practices and principles, and with meaningful input from consumer advocates and other stakeholders.
- If allowed revenues are modified over time, they should be modified in a way that is simple, transparent, and best reflects expected changes in cost pressures that may occur between rate cases.
- Reconciling rate adjustments should occur on a relatively frequent basis, at least once a year, to avoid any large impact on rates at the time of the adjustments.

²² Naturally occurring energy efficiency is that which results from normal market forces and technological improvements in the absence of utility programs or governmental intervention.

²³ Lowry, Makos and Waschbusch (2016).

²⁴ For example, Nevada and Missouri are currently considering whether to implement revenue regulation. See Public Utilities Commission of Nevada (2015) and Missouri Public Service Commission (2015). Note that the Nevada PUC held several workshops on decoupling mechanisms in spring 2015, finally adopting temporary regulations that modified the current lost revenue adjustment mechanism (which is not full revenue regulation) on June 10, 2015. Full revenue regulation may be adopted in the future.

²⁵ We use the term “revenue regulation” to refer to the general approach of severing the link between utility sales and revenues by setting revenues instead of setting prices; and we use the term “revenue regulation mechanism” to refer to the specific details of the ratemaking approach that is used in any one jurisdiction.



- Reconciliations should be capped to limit the amount that rates can be increased at any one point in time — e.g., 3 percent of annual utility revenues.
- Regulators can consider whether the utility’s allowed return on equity should reflect the fact that utility revenues, and therefore profits, will be less volatile under revenue regulation.

One other key design issue is the choice to apply revenue regulation to all utility customers or to only a portion of them. Some jurisdictions have chosen to exclude large commercial and industrial customers. One reason this is done is to avoid having to reassign large revenue shortfalls if customers of this kind sharply reduce their service requests. Another is a concern that utilities should maintain some incentives to retain such customers, encourage expansion of their local operations, and attract new customers to the service territory.

Role in a High DER Future

While revenue regulation has frequently been employed to mitigate a utility’s financial disincentive to support energy efficiency, it can also address a utility’s financial disincentive for other DERs that reduce customer electricity consumption from the grid, such as distributed generation and storage. Consequently, revenue regulation may be a useful ratemaking tool for regulators who wish to support the implementation of DERs. This is true regardless of whether regulators prefer that utilities or third parties play the lead role. Either way, utilities will be in a highly influential position regarding DER development and implementation.

Furthermore, electricity sales growth has declined in many regions of the United States in recent years for a variety of reasons. This has offset the financial benefit of the slower input price inflation that has occurred since the recession. As legislative and regulatory pressures increase over time to address climate change, electricity sales growth may decline even further. In the context of declining sales growth and increasing levels of DERs (whether naturally occurring through significant declines in technology costs, utility induced, third-party induced, or encouraged by public policies), utilities may need some form of revenue regulation because COSR may not provide them with sufficient revenues in a timely fashion to recover costs of serving customers.

Role in Relation to PBR

Revenue regulation is a fairly flexible tool that can be implemented in the context of traditional COSR or PBR. Efficiency PIMs are often added to revenue regulation to provide some “positive” incentive to use energy efficiency to slow rate base growth. The positive incentive can be further strengthened by combining revenue regulation and efficiency PIMs with a multi-year rate plan. MRPs in the past have often applied a price cap, but can instead feature a “revenue cap” without affecting the rest of the MRP mechanism.

A detailed analysis and discussion of the advantages and disadvantages of revenue regulation in a high DER future is beyond the scope of this study. We present the summary above to indicate how this ratemaking tool might or might not fit into the structure of PBR. We do not address this topic further in this report.

While revenue regulation has frequently been employed to mitigate a utility’s financial disincentive to support energy efficiency, it can also address a utility’s financial disincentive for other DERs that reduce customer electricity consumption from the grid, such as distributed generation and storage.



Lost Revenue Adjustment Mechanisms as an Alternative to Revenue Regulation

Lost revenue adjustment mechanisms (LRAMs) are sometimes used as an alternative to revenue regulation. Under this approach, utilities are compensated for the estimated loss of base revenue that results from their energy efficiency programs, and possibly also from distributed generation. The LRAM approach can be problematic and challenging for several reasons.

First, LRAMs significantly increase the need for accurate estimates of energy savings from energy efficiency programs. With large dollars riding on the outcome, proceedings to estimate lost revenues can be extremely contentious, distracting and resource intensive. For this reason, LRAMs tend to focus on utility energy efficiency programs with savings that are easy to estimate. This means that they do not fully eliminate the financial disincentive to promote sales, nor do they offset the financial disincentive for other initiatives that could reduce sales and costs, such as tighter building energy codes and appliance standards and time-varying rates.

Second, LRAMs should allow utilities to recover only a portion of lost revenues — the portion that is necessary to cover fixed costs that are embedded in rates. It can be difficult to properly isolate this portion of rates. If not done properly, the utility might recover more or less than necessary to be made whole.

Furthermore, LRAMs should not allow utilities to recover revenues that the utilities can recover by alternative means. For example, some vertically integrated utilities can offset lost revenues from efficiency programs by increasing off-system sales. The portion of off-system sales that are not passed through to customers can offset lost revenues from efficiency programs. It can be difficult to identify and quantify all of the ways that lost revenues are offset.

Furthermore, LRAMs often result in automatic, escalating annual increases in rates, which can become significant as customers adopt increasing levels of energy efficiency and distributed generation resources. Decoupling, on the other hand, typically results in modest adjustments to rates, and these adjustments can reduce rates as often as they increase rates.²⁶

In a high DER future, it would essentially be impossible and overly burdensome to accurately calculate lost revenues for all types of DERs. Revenue regulation does not suffer from the above challenges and can address all types of DERs and new technologies that might decrease or increase customer sales.

2.4. Performance Incentive Mechanisms

Targeted PIMs have been employed for many years to address traditional performance areas such as reliability, safety and energy efficiency. In recent years, these mechanisms have also received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and other less-conventional technologies and practices.²⁷

²⁶ Morgan, P., *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations*, Revised May 2013.

²⁷ See, for example, New York Public Service Commission (2014), which explores the role of PIMs to meet similar policy goals.



Targeted PIMs can be incorporated into any regulatory model, including traditional COSR and MRPs. By providing explicit metrics, targets, and in some cases financial rewards or penalties, PIMs can provide guidance on how utilities can meet state regulatory policy goals and encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the current regulatory system.²⁸

Targeted PIMs can be incorporated into any regulatory model, including traditional COSR and MRPs.

PIMs typically consist of four components:

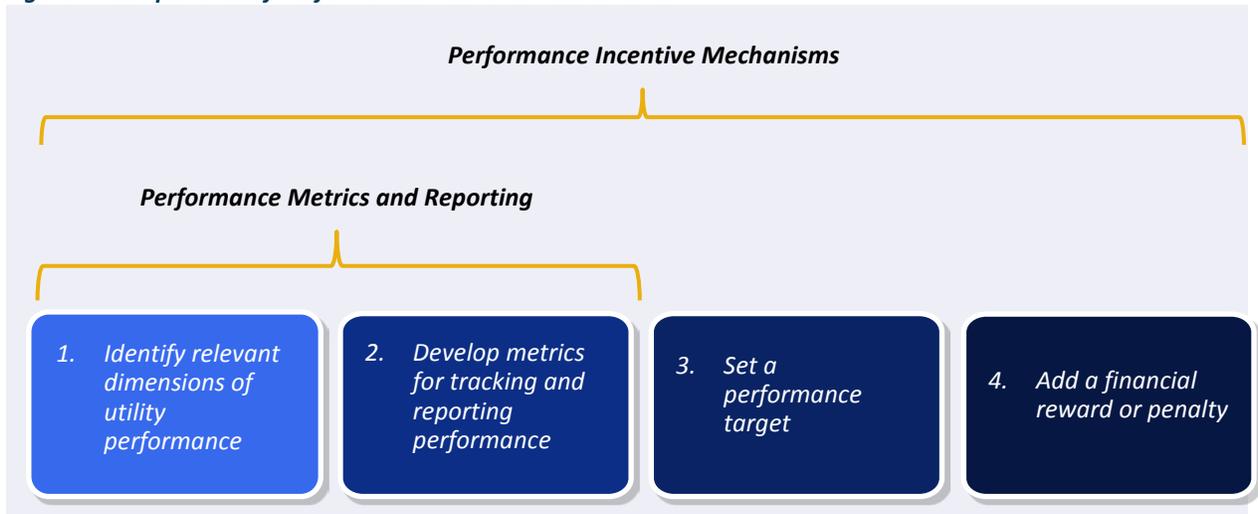
1. *Regulatory policy goals* that specify certain performance areas of interest, as well as objectives for those areas
2. *Metrics* that provide detailed information about the utility's operations in the specified areas of interest
3. *Targets* that reflect performance goals, as measured by the metrics
4. *Financial incentives* (rewards and/or penalties) that are based on the utility's performance relative to the target

Not all of these components need to be implemented to guide utility performance and guard against underperformance. In some cases, simply implementing metrics without targets or financial incentives is sufficient. Similarly, some metrics may have targets but no financial incentives. Regulators may wish to adopt these different components incrementally over time, based on experience gained from those elements that have been adopted. Figure 1 shows the components of performance incentive mechanisms. The sections that follow discuss metrics, targets and financial incentives in the context of regulatory policy goals.

²⁸ Whited, Woolf and Napoleon (2015).



Figure 1. Components of Performance Incentive Mechanisms



Metrics

A metric is simply a quantitative measurement. However, a performance metric should provide more than data; it should provide useful information for assessing how well a utility is progressing toward meeting policy objectives. Thus, a metric must be directly tied to the underlying policy goal and should be reasonably objective and subject to utility control. Identifying a metric that meets these criteria can be difficult.

Metrics must also be precisely defined and should use standard regional or national definitions where possible. To promote transparency and reduce the possibility that data will be manipulated, metrics should be easily measured and interpreted, and the data independently collected or verified.

Utility performance areas that have a long history of monitoring using metrics include reliability, safety, customer satisfaction, power plant performance and costs, as Table 2 indicates. Metrics for monitoring these traditional performance areas are generally well developed, and the data are readily available.



Table 2. Traditional Performance Areas

Performance Dimension	Purpose of Metrics
 Reliability	Indicate the extent to which service is reliable and interruptions are remedied quickly (e.g., SAIDI and SAIFI)
 Customer Service	Ensure that the utility is providing adequate levels of customer services
 Plant Performance	Indicate the operating performance of specific generation resources (e.g., availability factor)
 Cost	Indicate the cost of service (e.g., rates, unit cost and productivity)
 Employee Safety	Ensure that employees are not subjected to excessive safety risks
 Public Safety	Ensure that the public is not subjected to excessive safety risks

Source: Whited, Woolf and Napoleon (2015)

Evolving policy goals and industry challenges are increasingly prompting the development of new performance metrics. Areas of interest include system peak load management, usage per customer, network support services for distributed generation, and environmental impacts and clean energy goals. Table 3 provides examples of these emerging performance areas and metrics for tracking them. Metrics such as these will be important as states seek to both drive greater reliance on DERs and ensure that DERs are deployed effectively for greatest system benefit.

Table 3. Emerging Performance Areas

Performance Dimension	Purpose of Metrics
 System Efficiency	Indicate the extent to which the utility system as a whole is being operated more efficiently — e.g., in terms of load factor
 Customer Engagement	Indicate the extent to which customers are implementing energy efficiency, demand response, distributed generation and other DERs
 Network Support Services	Indicate the extent to which customers and third-party service providers have access to the network
 Environmental Goals	Indicate the extent to which the utility and its customers are reducing environmental impacts, including climate change

Source: Whited, Woolf and Napoleon (2015)



Performance Targets

Targets should be challenging, but realistically achievable. A number of analytical techniques can be used to determine targets, including historical performance (provided that historical conditions are still relevant), statistical benchmarking using peer utility data (after controlling for inherent differences among utilities), and utility-specific studies (such as engineering studies).²⁹

In all cases, the cost of achieving a performance target must be balanced with the expected benefits to customers. Some jurisdictions have utilized customer surveys to help determine the value of an incremental improvement in utility performance to customers. For example, Ontario and Alberta have relied on customer surveys to determine whether customers would be willing to bear the costs of improved reliability,³⁰ and Norwegian regulators have used surveys to construct a willingness-to-pay curve that represents how customers value various levels of reliability.³¹

In some cases, targets should be adjusted based on new information, new technologies or other factors. However, regulators should avoid sudden and significant changes to targets in order to provide the utility with certainty regarding longer-term investments. In addition, care must be taken not to unduly “ratchet” targets as utility performance improves.

Financial Rewards or Penalties

In general, financial rewards or penalties in PIMs should be large enough to capture management attention, but not overly reward or penalize the utility. Starting with a small reward or penalty avoids problems like financial instability, excessive costs to customers, and backlash that potentially undermines the entire performance incentive mechanism.³² However, rewards or penalties that avoid controversy may not be high enough to have sufficient incentive impact, and this shortcoming may not be realized for several years.

An additional feature of well-designed PIMs is that they avoid “cliff effects,” or substantial changes in earnings due to small changes in performance. Not only do cliff effects create uncertainty regarding utility earnings, but they also introduce significant controversy and contention to the measurement and verification process.

Deadbands (neutral zones around the target) can mitigate the implications of setting a target and associated incentives too high or too low, and reduce rate adjustments due to the natural volatility of metrics. Deadbands are frequently set at one standard deviation of historical performance, but may be larger or smaller based on sample size and the tolerance for error. That is, if a large amount of historical data is available, then one standard deviation is likely to capture most of the normal variation in a metric. For example, a target level for system reliability measured as the System Average Interruption Duration Index (SAIDI) may be set at 60 minutes, with a deadband of two minutes. Thus no rewards or penalties would be provided until performance fell outside of the 58 to 62 minutes range.

²⁹ Frontier analysis identifies the most efficient firms and creates an efficiency frontier based on these firms’ input usage per unit of output. Other firms are then assigned a score based on their efficiency relative to the efficiency frontier. For further information, see Shumilkina (2010).

³⁰ Pollara (2010) and Alberta Utilities Commission (2012).

³¹ Growitsch (2009).

³² Some performance areas may need larger financial incentives than others. Also, if regulators wish to fundamentally shift utility incentives away from current incentives, then the combined effect of PIM financial incentives may need to be significant.



In some cases, asymmetrical rewards or penalties may be appropriate. Reward-only incentives are easier for utilities to accept, especially for metrics that are new and are not subject to close utility control, and may result in more collaborative and less adversarial processes. On the other hand, penalty-only incentives are sometimes appropriate when performance above the target provides little additional benefit to customers.

ENERGY EFFICIENCY PIMS

Energy efficiency is the most common focus of PIMs in use in the United States today, and the experience with these PIMs can shed light on the opportunities and the challenges of using PIMs in the context of DERs in general. Energy efficiency PIMs have been in use since the early 1990s. They are intended to: (a) help overcome utility resistance to reduce sales; (b) encourage utility management buy-in for energy efficiency programs; (c) provide incentives for utilities to deliver successful, effective programs; and (d) ultimately align utility incentives with energy efficiency goals established through public policy.

Almost 30 states have established some sort of PIM for electric energy efficiency programs.³³ While efficiency PIM designs vary across the states, they fall into four general categories:³⁴

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

Most energy efficiency PIMs have several incentive points — for example: (a) a threshold point below which no incentives are earned (e.g., 80 percent of savings); (b) a target point at which the target amount of the incentive can be earned (e.g., 100 percent of savings); and (c) a cap beyond which no additional incentives can be earned (e.g., 120 percent of savings). The amount of money that is made available for efficiency PIMs varies widely across the states, but tends to be on the order of 5 percent to 15 percent of energy efficiency program budgets.

Energy efficiency PIMs are generally recognized as being effective in achieving more aggressive and more effective energy efficiency programs. Two recent studies found that PIMs significantly contributed to buy-in by corporate management, motivated utility management and influenced energy efficiency planning.³⁵

Note that energy efficiency PIMs alone do not remove the utility's incentive to increase sales or to increase rate base. Revenue regulation, or some comparable approach to address lost revenues, is needed to offset the utility throughput incentive. In addition, energy efficiency PIMs alone do not provide financial rewards to eliminate the utility incentive to increase rate base. But they do offset this incentive and typically provide sufficient incentive to encourage utilities to implement successful energy efficiency programs.



Performance Incentive Mechanisms in a High DER Future

PIMs can counter undesirable incentives inherent in the existing regulatory framework. They also can provide guidance and incentives to pursue new regulatory goals, such as interconnecting distributed generation and storage, investing in grid modernization, or adopting practices to support electric vehicles. Table 4 provides examples of metrics that regulators may wish to consider in a high DER future, grouped into two categories: DER deployment and network support services. DER deployment metrics can provide an indication as to how well utilities are facilitating adoption of DERs through utility programs (such as energy efficiency and demand response programs), electricity pricing structures (such as net metering and time-varying rates), and customer usage information. Metrics related to network support services, on the other hand, are focused on how well the utility is facilitating DERs by providing appropriate grid infrastructure and data access.

Table 4. Examples of Potential DER-Related Performance Metrics

Area	Metric	Purpose
Distributed Energy Resource Deployment	Energy efficiency (EE)	Indication of participation, energy and demand savings and cost-effectiveness of EE programs
	Demand response (DR)	Indication of participation, demand savings and cost-effectiveness
	Distributed generation (DG)	Indication of the technologies, rate of DG penetration, energy and demand savings and cost-effectiveness
	Energy storage	Indication of the technologies, capacity and growth of utility and customer-sited storage installations and their availability to support the grid
	Information availability	Indication of customers' ability to access their usage information
	Time-varying rates	Indication of saturation of time-varying rates
	Electric vehicles (EVs)	Indication of customer adoption of EVs and their availability to support the grid
Network Support Services	Advanced metering capabilities	Indication of metering functionality
	Interconnection support	Indication of DG installation support
	Third-party access	Indication of network access by third-party developers
	Provision of customer data	Indication of customer access to relevant data

2.5. Multi-Year Rate Plans

Salient Features

MRPs are the most common approach to PBR around the world. The basic idea is to compensate a utility for its services for several years with revenue that, while reflective of cost pressures, does not closely track the utility's own cost of service. The competitive market paradigm provides some intuition for this approach. Imagine, for example, that utility distribution companies in the northeastern United States were paid a set fee to provide quality electric service to each customer of a certain type, and that these fees were designed to permit distributors in the region as a whole to earn a competitive rate of return in the longer run. With revenue that is independent of their own cost of service, utilities would then have strong incentives to contain their costs using DERs and other strategies. Benefits of the resultant industry productivity growth in the region could be passed through to customers. Rates paid to individual utilities could in principle be adjusted to reflect variations in local input prices, system undergrounding, and other external business conditions.



While a regulatory system of this kind is technically feasible, real-world MRPs are rather different because regulators and utilities alike do not want the revenues of individual utilities to stray too far from their cost of service. MRPs utilize two tools to relax the link between a utility's own cost and its revenue:

1. A moratorium is imposed on general rate cases that typically lasts two to four years. These moratoria can permit a substantial reduction in regulatory cost.
2. Between rate cases, an attrition relief mechanism (ARM) automatically adjusts rates or the revenue requirement for changing business conditions such as inflation and customer growth without linking the relief to the utility's own cost growth.

MRPs typically address some costs separately from ARMs using cost trackers. Tracker treatment is useful for costs that are difficult to address using ARMs.

The combination of a rate case moratorium and the ARM approach to rate escalation can strengthen cost containment incentives and permit an efficient utility to realize its target rate of return on equity (ROE) despite a material reduction in regulatory cost.

Some MRPs have earnings sharing mechanisms (ESMs), which share surplus or deficit earnings, or both, between utilities and customers. These earnings result when the ROE deviates from its commission-approved target. Off-ramp mechanisms may permit suspension of a plan under pre-specified outcomes such as persistently extreme ROEs.

Plan review and termination provisions are also important in MRPs. Some plans require rates to be reset in a rate case. When this happens, any lasting cost savings or inefficiencies realized during the plan are passed entirely to customers, and this weakens utility performance incentives. Some plans provide for a review of the MRP toward the end of the plan period, and these reviews may result in a plan extension without a general rate case.

Other plans provide for a rebasing at the end of a plan that deliberately lacks a full true-up of the revenue requirement to the utility's net cost. Provisions of this kind are sometimes called "efficiency carry-over mechanisms" because they permit the utility to keep some benefits of lasting performance gains, and perhaps also to absorb some lasting costs of poor performance after a plan expires. A utility might thereby be able to keep for some period of time a margin from sales related to electric vehicles (EVs) or savings in substation costs that it achieved from aggressive use of DERs. These mechanisms can strengthen incentives to pursue efficiency gains without unusually long plan periods that complicate ARM design.

Most MRPs also include PIMs. These have in the past been used chiefly to balance incentives for cost containment with incentives to pursue other goals that matter to customers and the public. PIMs used in MRPs for electric utilities have been especially common for energy efficiency, reliability and customer service (e.g., telephone response time, timeliness in meeting scheduled appointments and connections, and the accuracy of invoices). MRPs for vertically integrated utilities may sensibly include PIMs for generator performance. In the future, MRPs are likely to include PIMs that address new concerns such as peak load management and the quality of connections and other services offered to distributed generation customers.

MRPs can also encourage better marketing by utilities where regulators deem this desirable. Rate cases are less frequent, and this reduces the chore of allocating costs across service classes. Rate adjustments



that are required (due, for example, to ARMs) can be effected using formulas that insulate one group of customers from rate and service offerings to other customers. The MRP framework therefore reduces concerns about affording utilities more marketing flexibility. MRPs can also permit utilities to keep benefits of improved marketing longer, especially when they feature a well-designed efficiency carry-over mechanism. Utilities can then have stronger incentives to develop market-responsive rates and services in targeted areas.

MRPs can improve utility incentives to embrace DERs, if properly designed. Inherent advantages include the general incentive they can provide to slow rate base growth. Since DERs can be effective tools for reducing rate base growth, utilities have a stronger incentive to embrace them.

One area where improved marketing is valuable is service to price-sensitive, large-load customers. Power costs are especially important to these customers, and they often have the option of self-generating or operating in other service territories. Better marketing is also needed for green power and EV rates and services for all customer classes.³³ In addition, advanced metering infrastructure can be used to provide time-sensitive base rates that help utilities send the right price signals and encourage customers to use their systems in less costly ways. Advanced metering infrastructure, distributed storage, and other new distribution technologies open the door to many new value-added services, including premium quality services. Utilities can also work harder to boost traditional sources of other operating revenues such as line attachment fees for cable and telecommunications (telecom) companies.

Application to DERs

MRPs can improve utility incentives to embrace DERs, if properly designed. Inherent advantages include the general incentive they can provide to slow rate base growth. Since

DERs can be effective tools for reducing rate base growth, utilities have a stronger incentive to embrace them. For example, if a utility uses DERs to reduce the need for substation capex, it can keep some of the cost savings for several years, and possibly longer if there is a well-designed efficiency carry-over mechanism.

MRPs can also incorporate mechanisms to weaken the short-term link between revenue and sales, such as revenue regulation. When an MRP features revenue regulation, the ARM escalates allowed revenue. Utilities in California and Hawaii, which have experienced the highest levels of distributed solar generation penetration in the United States, operate under MRPs with revenue regulation.³⁴ A utility's incentive to embrace DERs under an MRP can be further strengthened by the addition of DER-related PIMs and by tracker treatment of DER-related expenditures.

³³ A base rate for EV service could, for example, be tied to the price of gasoline.

³⁴ Solar generation is also encouraged in these states by other conditions, including strong sunlight.



Role of Consumer Advocates

The role of consumer advocates may change in an MRP regulatory system. Rate cases may occur less frequently but those that do occur require more vigilance. Consumer advocates must pay a great deal of attention to the details of MRP designs, which will have important implications for customers. Consequently, consumer advocates may need to develop a different set of skills to be able to effectively participate in the design of MRPs.

Consumer advocates may need to develop a different set of skills to be able to effectively participate in the design of MRPs.

ARM Design

The incentive power of an MRP depends crucially on its ability to reduce the frequency of rate cases and on its reliance on ARMs rather than trackers to address most costs. ARMs can also play an important role in ensuring that benefits from MRPs flow through to customers. ARM design is thus a key issue in a proceeding to approve an MRP. Four approaches to ARM design are well-established: forecasts, indexing, freezes, and hybrids of these approaches.

Forecasts

A forecast-based ARM bases rate adjustments primarily on multi-year forecasts. In the United States, ARMs based on cost forecasts typically increase revenue by a certain predetermined percentage in each year of the plan. This gives allowed rates or revenue a stair-step trajectory.³⁵ Stair-step ARMs are popular in the United States and are currently used by electric utilities in California, Georgia, North Dakota and New York.³⁶

The forecast approach to ARM design has some advantages for electric utilities under today's business conditions. Many commissions are already engaged in integrated, multi-year planning exercises, such as integrated resource planning and the integrated distribution planning underway in California. These exercises reduce the incremental cost of developing stair-step ARMs based on cost forecasts.

On the other hand, regulators and intervenors in some states have shown a reluctance to sign off on multi-year cost forecasts. Furthermore, a multi-year forecast of total cost must consider numerous costs (e.g., distribution line maintenance) that are not closely related to DER and smart grid strategies. Since it is difficult to ascertain the value to customers that is implicit in a cost forecast, regulators in some countries, including Australia, Canada and Britain, have felt the need for costly engineering and benchmarking studies before signing off on ARMs based on forecasts.³⁷

Indexing

An indexed ARM is developed using industry cost trend research. The following general formula drawn from cost theory is useful in the design of revenue caps for utility distribution companies:

³⁵ Stair-step ARMs in the United States are not always based on multi-year forecasts of all costs, however. In California, for example, the capex budget may be set for several years at the level approved for a forward test year used in the utility's general rate case.

³⁶ California Public Utilities Commission (2014); Georgia Public Service Commission (2013); North Dakota Public Service Commission (2014); New York Public Service Commission (2015).

³⁷ Ofgem (2014); Australian Energy Regulator (2015); and Research Team from the Australian Energy Regulator and the Regulatory Development Branch of the Australian Competition and Consumer Commission (2012).



$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity} + \text{growth Customers}$$

This provides the basis for the following revenue cap index:

$$\text{growth Revenue} = \text{Inflation} - X + \text{growth Customers}$$

where a recent measure of inflation such as a gross domestic product price index is used. Revenue growth would be slow in a period like the present that features slow input price inflation but would accelerate with rising inflation. *X*, the “productivity” or “*X*” factor, reflects the average productivity trend of a group of distributors. ARM escalation therefore reflects normal productivity growth, to the benefit of customers. A “stretch factor” (aka consumer dividend) is often added to *X* to share with customers the benefit of the stronger performance incentives expected under the plan.

Broad regional or national peer groups are commonly used to establish the base productivity trend. The peer group can in principle be customized to mirror special circumstances of the subject utility. For a utility needing accelerated system modernization, for instance, *X* could reflect the productivity trend of utilities that have previously faced this challenge.

The indexing approach to ARM design was developed in the United States.³⁸ It is currently used by the Federal Energy Regulation Commission to regulate U.S. oil pipelines and several smaller energy utilities and is also widely used in Canada and countries overseas, including New Zealand. United States energy utilities that previously operated under indexed ARMs include Bay State Gas, Boston Gas, Central Maine Power, San Diego Gas & Electric, Southern California Gas and NSTAR Electric.

Hybrids

A hybrid approach to ARM design uses a combination of methods. In the United States, a hybrid approach is used in which revenue that addresses utility opex is indexed, while revenue that addresses capital cost has a stair-step trajectory. This approach to ARM design was developed in California and has been used several times there.³⁹ Hybrid ARMs have recently been used in MRPs of Hawaiian Electric and Southern California Edison.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but sometimes apply to rates for commodity procurement.⁴⁰ Rate freezes are compensatory for utilities when growth in their net cost of service matches or is slower than the growth in their billing determinants. Such favorable operating conditions have occurred over the years under special circumstances in the electric industry. For example:

- Electric utilities in the early postwar period experienced rapid growth in productivity and system use and slow inflation.

³⁸ Early American papers encouraging the use of input price and productivity research in ARM design include Sudit (1979) and Baumol (1982).

³⁹ Early approvals of hybrid ARMs included the 1985 CPUC decisions for most of the large California energy utilities.

⁴⁰ Comnes, Stoft, Greene and Hill (1995).



- Following major generating plant additions in the 1980s and early 1990s, some vertically integrated utilities experienced unusually slow cost growth due to slow inflation and declining generation rate bases. Several U.S. vertically integrated utilities operated without rate cases for more than 15 years.⁴¹
- Mergers and acquisitions facilitate rate freeze agreements by creating special cost containment opportunities.

Favorable circumstances like these are less common today. Utility distribution companies cannot benefit from declining generation rate bases. Some utilities need high capex for accelerated system modernization, increased resiliency, cleaner generation, or a combination of these factors. There is typically little sales volume growth between rate cases available to finance cost growth. Nonetheless, rate freezes have recently been approved for several U.S. electric utilities.⁴² These are typically vertically integrated utilities with limited need to increase generation rate base. Provided that a few costs that are growing are tracked, they do not need any further rate escalation for several years. For vertically integrated utilities the tracked cost usually includes the cost of generating plant additions.

Rate freezes can maintain or exacerbate a utility's throughput incentive, and can therefore create a disincentive to DERs. This concern can be addressed by implementing revenue regulation. Under an MRP with revenue regulation but with no ARM, the utility would be subject to a "revenue freeze," instead of a rate freeze, and would therefore not be harmed by lost revenues from DER. This could also be taken a step further by establishing an ARM that escalates allowed revenue only for customer growth, producing a "revenue per customer freeze."

Role of Benchmarking

Statistical benchmarking can be helpful in ARM design using all of these approaches. The Ontario Energy Board, for example, regulates most power distributors with MRPs featuring price cap indexes of "inflation – X" form.⁴³ The X factor is based in part on the trend in the productivity of Ontario utility distribution companies and in part on stretch factors derived from a Board-commissioned econometric benchmarking study. The Board also permits "custom" MRPs but requires that their ARMs be designed using benchmarking and productivity research.⁴⁴

MRP Precedents

In North America, the use of MRPs began on a large scale in the 1980s. MRPs have been especially popular where utilities have a special need for marketing flexibility. Such plans have helped railroads, oil pipelines, and telecom utilities serve markets with diverse competitive pressures and complex and changing customer needs. For example, telecom utilities were given a freer hand to offer competitive rates to customers in central business districts, where competition was greatest, and to offer value-added (aka discretionary) services, such as caller ID, that make use of new digital technologies. Rates for standard services to residential customers were insensitive to such initiatives. For example, most telecom plans featured index-based price caps that separately escalated the prices of several groups of

⁴¹ Vertically integrated utilities that went more than 15 years between rate cases during this era included Florida Power & Light, Indianapolis Power & Light, and Carolina Power & Light.

⁴² These include Appalachian Power, Arizona Public Service, Dominion Virginia and Public Service of Colorado.

⁴³ Ontario Energy Board (2013).

⁴⁴ Ontario Energy Board (2012).



services (aka “baskets”) and did not include earnings sharing. Rates for basic residential services were often frozen.

Under ratemaking reforms in the Staggers Rail Act of 1980, which included MRPs, U.S. railroads were also granted increased marketing flexibility. They used this flexibility to address intermodal competition from truckers and waterborne carriers, manage their costs better, and meet special customer needs. Lower rates were offered to customers making less costly service requests. For example, lower rates were offered for unit trains and pickups (and drop-offs) along high traffic corridors.⁴⁵

In the U.S. electric utility industry, MRPs were first used extensively in California, where a Rate Case Plan was established in the 1980s that, with modifications, has limited the frequency of general rate cases to this day.⁴⁶ Iowa, Maine, Massachusetts and New York have also been MRP innovators. An MRP for Central Maine Power afforded the company considerable flexibility in marketing to price-sensitive paper mill customers.⁴⁷ MidAmerican Energy operated under a lengthy rate freeze that extended to its energy costs but permitted the company to keep margins from its off-system sales.⁴⁸ The use of MRPs in the United States has recently spread to vertically integrated utilities in a diverse collection of other states that includes Colorado, Florida, Georgia, Virginia and Washington.⁴⁹

In Canada, MRPs are becoming mandatory for natural gas and electric power distributors in the four most populous provinces. Ontario, which regulates more than 70 power distributors, is now on its fourth generation of MRPs for these utilities. Overseas, the privatization of many energy utilities in the last 25 years has forced governments to reconsider their approach to regulation. The majority has chosen MRPs over COSR. Regulators in Australia, Britain, Germany, the Netherlands and New Zealand are MRP leaders.

An indication of the potential incentive impact of MRPs can be found in the experience of Central Maine Power, which operated under three successive MRPs (called “Alternative Rate Plans”) from 1995 to 2013. Figure 2 compares the trend in the multifactor productivity of the power distributor services of Central Maine Power to those of other distributors in the mid-Atlantic and northeast United States since the mid-1990s.⁵⁰

Figure 2 shows that the company attained productivity growth well above the industry norms in the northeast United States during these years. This was accomplished primarily through superior capital productivity growth. The MRPs seem to have encouraged Central Maine Power to slow its rate base growth.⁵¹

⁴⁵ Railroads today operate under a different form of regulation in which most rates and services are deregulated but shippers can contest rates where competition is limited and request rates based on benchmarks or rough estimates of the stand-alone cost of service provision. This regulatory system has given railroads the flexibility and incentive to make complex and changing rates and service offerings in competitive markets. One manifestation of this flexibility has been their recent success in capturing a sizable share of the traffic from new oilfield developments.

⁴⁶ California Public Utilities Commission (1985).

⁴⁷ Maine Public Utilities Commission (1995).

⁴⁸ Iowa Utilities Board (1997); Iowa Utilities Board (2001); and Iowa Utilities Board (2003).

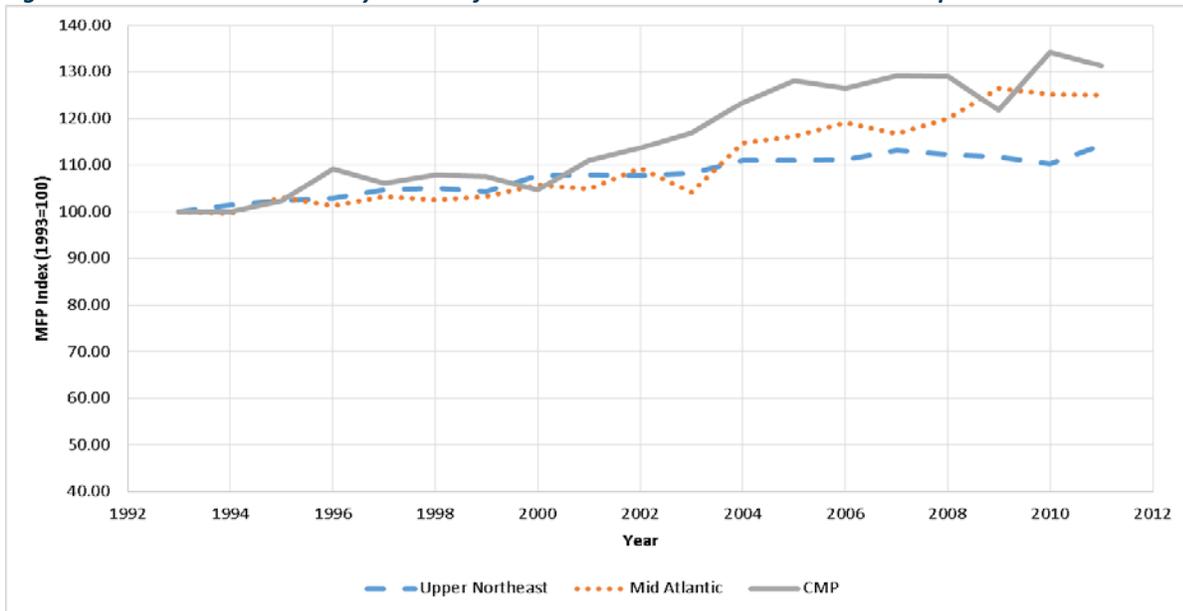
⁴⁹ Colorado Public Utilities Commission (2012); Florida Public Service Commission (2013); Georgia Public Service Commission 2010; and North Dakota Public Utilities Commission (2014).

⁵⁰ Lowry (2013).

⁵¹ At the end of the rate period indicated in Figure 2, CMP made a request for an MRP that would have significantly increased its revenue to allow for new capital expenditures. The CMP rate case was eventually settled, with a stipulation to terminate PBR in Maine and return to a system more akin to COSR. Maine Public Utilities Commission (2014).



Figure 2. Distribution Productivity Trends of Central Maine Power and Two Peer Groups



The superiority of multifactor productivity growth in the Mid-Atlantic states to those in the upper Northeast (New York and New England) is also noteworthy, since several of the best-performing Mid-Atlantic utilities operated under lengthy rate freezes with no earnings sharing. Statistical benchmarking studies by PEG Research have, similarly, shown that vertically integrated electric utilities that have operated for long periods without rate cases often display superior cost management.

2.6. British RIIO System as an Example of Comprehensive PBR

For more than 25 years, Great Britain has used MRPs (called “price controls”) to regulate its electric utilities. Each utility’s revenue requirement forecast during the five-year rate period provided the basis for an inflation – X escalator (referred to as “RPI-X”). The MRP scheme has evolved continually over the years. For example, the plans have in recent years featured a broader array of PIMs.

In 2008 the British Office of Gas and Electricity Markets (“Ofgem”) launched a fundamental review of the regulatory framework. The review found that the traditional PBR approach was no longer well-suited to meet changing policy priorities and industry challenges. While PBR provided incentives to reduce costs, the five-year term was found to be too brief to encourage utilities to make highly innovative investments with longer-term payback periods. Further, the regulatory model gave utilities little incentive to pursue policy objectives other than cost control and service quality maintenance. Finally, the RPI-X approach was found to be too inflexible to effectively accommodate step-changes in technology.

Out of this review and stakeholder discussion was born a revised, more comprehensive and performance-based form of MRP. This new framework is referred to as “RIIO,” an abbreviation for Revenue = Incentives + Innovation + Outputs.



Key elements of RIIO include:

- *Rate case moratorium.* The rate period has been extended to eight years in order to provide greater innovation incentives by allowing the utilities to retain the cost savings for a longer period of time.
- *Base revenues, attrition relief mechanism and capital expenditures.* The utility's allowed revenues for each year of the rate plan are based on the total cost forecast in a regulator-approved business plan for each utility. A rate of return is earned on a certain percentage of the total expenditures, rather than specifically on capital investments.
- *Greater focus on PIMs.* A larger proportion of the utility's revenues are tied to PIMs.

Below we describe these elements, the rationale for each and key challenges.

Rate Case Moratorium

Prior to RIIO, electric utilities in Great Britain were regulated under five-year price control plans. However, the five-year duration was deemed inadequate for encouraging the utilities to focus on long-term initiatives to reduce costs and enhance service quality, or to experiment with innovative strategies and technologies. For this reason, RIIO has eight-year plan periods, with only limited opportunity to modify allowed revenues through "reopeners." That is, only in cases of significant changes to input costs or government regulations will the utilities be able to request modifications to base revenues. In this manner, RIIO attempts to retain strong cost control incentives and a focus on long-term investments, while providing a safety valve to accommodate uncertainty regarding the future.

Base Revenues, Attrition Relief Mechanism and Capital Investments

RIIO continues the reliance on multi-year forecasts of utility cost (referred to as "business plans") to design ARMs. Revenue requirements are later adjusted for inflation. Some innovative methods are used in revenue requirement determination.

Business plans: Revenue requirements under RIIO are set based on eight-year utility business plans. Requirements are established in real terms and then escalated for inflation. Because the business plan plays such a critical role in determining utility revenues, substantial effort is made to ensure that the plans are thorough, realistic and appropriately justified. Business plans must demonstrate that the utility will provide sufficient "value for money" to customers through pursuing efficiencies and delivering on the six categories of additional "outputs" described in the next section. In developing their business plans, utilities are also required to assess alternative options for delivering outputs, evaluate the long-term costs and benefits for each alternative, and incorporate stakeholder input.



The plans undergo significant scrutiny from regulators, who use statistical benchmarking and independent engineering analysis to determine whether the costs included in the plans are reasonable. Revenue requirements are based 75 percent on Ofgem’s assessment and 25 percent on the utility’s cost forecast. Once approved, the business plans form the basis for revenue adjustments over the rate period. Following are two key components of the business plan process:

- *Fast Track.* A utility that submits a business plan that Ofgem deems of sufficiently high quality in its initial assessment can receive “fast-track” treatment.⁵² Fast-tracked utilities in the first round of RIIO for power distributors finished the majority of the proceeding a year ahead of the remaining utilities.
- *Information Quality Incentive.* To encourage utilities to provide honest assessments of their future costs, an Information Quality Incentive (IQI) mechanism is used. The IQI has three features: it finalizes the revenue requirement, determines the sharing of variances between actual and forecasted cost, and provides an immediate reward or penalty based on the reasonableness of the company’s forecast.

In the spirit of work by Nobel prize-winning economist Jean Tirole, the IQI also functions as an incentive-compatible menu.⁵³ In such a menu, a utility can choose from among several combinations of ratemaking provisions, such as revenue and earnings sharing factors. The menu is designed so that the utility, by its choice, reveals the cost that it can achieve, thereby overcoming information asymmetry. For example, a utility that requests a lower level of revenues (more closely matching Ofgem’s assessment of efficient costs) would be rewarded with additional income and a greater portion of any savings relative to allowed cost. A utility is also rewarded when its actual cost is similar to its forecast. In contrast, a utility that requests a higher level of revenue (that exceeds Ofgem’s estimate of efficient cost) would be required to pass on a higher percentage of surplus earnings to customers and receive an initial penalty.

Totex: Under RIIO, capital and operating expenditures are combined into one category: “total expenditures,” or “totex,” in determining revenue requirements. The utility is afforded a return on a predetermined percentage of totex, regardless of whether the utility’s capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus noncapital projects.

Performance Incentive Mechanisms

Under RIIO, PIMs take on a larger role. Whereas early PBR plans incorporated service quality standards into plans to guard against service degradation, RIIO employs PIMs to proactively guide the utility in its actions in order to achieve a broader array of policy objectives. These objectives are grouped into six “output” categories:

⁵² Ofgem’s initial assessment reviewed the business plans according to five broad criteria: process, outputs, efficient expenditure, efficient finance, and uncertainty and risk. The process criteria focused on the clarity of the business plans, the extent of stakeholder input in the plan, and whether or not the plan seemed reasonable overall. The outputs criteria explored whether or not the business plan complied with the strategy decision on outputs. Efficient expenditure encompassed benchmarking of total expenditures (totex) and whether a utility had justified its expenditures given the level of outputs and reviewed possible alternatives. Efficient financing reviewed the utility’s compliance with the strategy decision, its consistency with past practice, and the justification of the company’s financing plan. Uncertainty and risk measured the business plan’s clarity on the uncertainty and risk that it faces and the mitigation efforts proposed.

⁵³ See Laffont and Tirole (1993).



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

Each of the six primary output categories contain a set of “secondary deliverables” defined by specific metrics. Targets for some deliverables are set by Ofgem with input from stakeholders, while targets for other deliverables (such as asset health) are proposed by the utilities themselves in their business plans. All targets proposed by utilities must be justified in terms of costs and benefits to customers and informed by stakeholder engagement.⁵⁴

However, not all outputs under RIIO have financial incentives. For example, the Reliability and Safety Working Group rejected the use of incentives (financial or reputational) for safety, as it was felt they could result in unwanted implications for incident reporting. Moreover, utilities are already required to comply with health and safety standards set by another governmental agency and would be subject to enforcement action from that agency in the event of noncompliance.⁵⁵

The PIMs in RIIO place a larger amount of revenues at stake than is common in North American MRPs. The results of Ofgem’s modeling suggest that actual power distributor ROEs may range from approximately 2 percent to more than 10 percent, depending on how well the utilities achieve their targets.⁵⁶ A significant portion of this variability is due to the IQI, which is used to determine the utility’s allowed revenues, as discussed above.

The magnitude by which utility earnings can fluctuate under RIIO highlights the importance of developing metrics and targets carefully. Setting a target too low could easily result in excessive earnings, while setting a target too high could jeopardize the financial health of the company, also resulting in negative impacts on ratepayers. Stakeholder involvement in setting metrics and targets is critical for reducing contention in later proceedings and helping to ensure that targets are immune from gaming. Stakeholders must be confident that positive financial incentives were justly earned in order to reduce the possibility that such earnings will be taken away from the utility, thereby undermining the incentives embedded in the plan.

Choosing objective metrics and setting targets at an appropriate level are not easy tasks, however. After several years of stakeholder consultations, several metrics have yet to be fully specified, while others (such as environmental impacts) are not yet mature enough to attach financial incentives.

⁵⁴ Ofgem (2012).

⁵⁵ *Id.*

⁵⁶ Ofgem (2014).



Role of RIIO in a High DER Future

RIIO is often cited as a potential model for regulating the “utility of the future.”⁵⁷ In general, there is a call for new regulatory models that are more focused on performance, outputs, and outcomes, and less focused on regulatory review of utility investments after the fact.

The RIIO model offers several components that appear to provide better utility incentives relative to those provided by COSR. An MRP with an eight-year plan term provides strong cost containment incentives. Incorporating a comprehensive set of PIMs might provide utilities with more direction and incentive to adopt evolving technologies, including DERs. Setting allowed revenues based on long-term business plans might help utilities plan for and make investments in new technologies such as smart grid. Use of the “totex” method for earning a rate of return might reduce the utility’s incentive to invest in large capital projects.

The RIIO model offers several components that appear to provide better utility incentives relative to those provided by COSR.

On the other hand, RIIO includes a highly complex and expensive approach to MRP design, with considerable risk for both utilities and consumers, due in part to the eight-year term between rate cases. Lessons the United States can learn from RIIO are discussed further in Chapter 5.

⁵⁷ See, for example, Lehr (2013); Binz and Mullen (2012); and Spiegel-Feld and Mandel (2015).



3. Regulatory Considerations Regarding PBR

There are several issues that regulators and stakeholders should investigate when deciding whether and how to implement some form of PBR. For example:

A. Does the existing regulatory framework provide appropriate utility incentives in a high DER future?

Regulators and stakeholders should begin by assessing the history and experience with the current regulatory framework in their state. Does the existing framework provide appropriate guidance, incentives, operating flexibility, and a fair opportunity for recovery of efficient costs for utilities at reasonable regulatory cost in a high DER future? How well does the existing regulatory framework support state energy policy goals, particularly goals related to DERs?

B. To what extent should regulators and other stakeholders guide outcomes?

Relative to COSR, PBR allows regulators to provide more guidance on desired outcomes. When considering whether and how to implement PBR in a high DER future, regulators and stakeholders should consider how much regulatory guidance utilities will need. MRPs provide utilities with guidance on the general performance areas related to operational efficiency and reduced costs, while the decisions for how to achieve improved performance are left to the utility. PIMs, on the other hand, typically provide utilities with much more focused regulatory guidance on specific performance areas and goals.

C. To what extent should utilities be provided with flexibility and regulatory certainty?

In a high DER future, utilities may need more flexibility than is available under COSR to quickly respond to emerging technologies and evolving customer needs. On the other hand, utilities typically prefer to have some regulatory certainty regarding the ability to recover investments in innovative or unconventional technologies and resources. When considering whether and how to implement PBR in a high DER future, regulators and stakeholders should consider how much guidance utilities need before making investments in innovative initiatives and how much certainty they need with regard to recovering those investments.

D. What are the various PBR options available?

As described in Chapter 2, there are a variety of PBR elements that can be used in different combinations. Which elements are most appropriate for the particular jurisdiction? What mix of PBR tools make sense for utilities and jurisdictions in different industry contexts? For example, are MRPs preferable to stand-alone PIMs?

E. What are the key PBR design issues?

How should PBR mechanisms be designed to achieve the ultimate goal of improved utility performance? Which of the PBR elements described in Chapter 2 have proven to be most effective in the past? Would it be best to implement a mix of multiple PBR elements (such as MRPs with cost trackers and PIMs)? Which specific PBR design issues are more relevant in a high DER future?



F. Will PBR provide the best outcome for customers?

Will PBR provide overall benefits to customers, relative to the existing regulatory framework? Will the operational efficiencies, cost reductions, and other benefits be shared with customers? Will PBR increase customer risk and, if so, are there countervailing benefits? How should regulators balance risks between utilities and their customers? Will PBR create opportunities for utilities to manipulate the mechanism or game the results in any way?



4. Criteria for Evaluating PBR

A move to PBR is worthwhile when it yields greater net benefits than COSR and shares these benefits fairly among stakeholders in the regulatory process. As described above, the potential benefits of PBR include improved utility operating performance due to stronger performance incentives and increased operating flexibility (including marketing flexibility, where this is deemed necessary while protecting customers from any untoward consequences). The performance dimensions that matter most to customers include the cost and quality of service. Other potential benefits include fewer negative externalities from utility operations and a more efficient regulatory process. Possible costs of PBR include greater operating risk and an unfair allocation of the costs and benefits between utilities and other stakeholders.

To determine whether PBR is achieving its objectives, PBR can be evaluated according to responses to the following questions:

Operating Performance

Cost

- Does PBR encourage better cost performance?
 - Is there improved attentiveness to cost containment?
 - Have environmental costs been reduced?
 - Has the utility embraced DERs as cost containment tools?
 - Are new technologies being used appropriately?
 - Is outsourcing of certain utility functions being done where appropriate?
 - Is the utility facilitating third-party roles — e.g., in market development?

Quality

- Does PBR encourage optimal reliability and customer service quality, including service to customers with on-site generation and storage?

Market Effectiveness

- Does PBR encourage utilities to offer the right mix of rates and services? For example:
 - Is the utility developing tariffs that send the right price signals to customers?
 - Is the utility promoting efficient use of power in clean energy applications (e.g., EVs)?
 - Is the utility providing a market-responsive array of grid-supplied clean power alternatives?
 - Is uneconomic bypass being successfully avoided?



- Is the utility offering value-added services made possible by new technologies?
- Is the utility providing grid services that support new markets?

Efficiency of Regulation

- Has regulation been streamlined where possible so that resources can be redeployed to more valuable uses (such as integrated resource planning and other non-rate-case proceedings)?

Risk

- Does PBR involve excessive or undue risk to utilities?
- Does PBR involve excessive or undue risk to customers?
- Is the allowed rate of return under PBR commensurate with operating risk?

Distribution of Benefits

- Do utilities have a reasonable opportunity to recover their efficient cost of service?
- Are the net benefits of performance improvements fairly distributed? For example, is a superior (inferior) performer likely to earn a superior (inferior) return? Can utilities keep some of the benefits from the lasting improvements in performance that they achieve?
- Is regulatory capture of the process by utilities avoided?



5. Perspectives on PBR Issues

As illustrated in the previous chapters, PBR is comprised of numerous elements, each of which offers opportunities as well as risks. These opportunities and risks are often different for the various stakeholders in the regulatory process. To highlight some of these differences, this chapter examines key PBR elements and different approaches to PBR implementation from the perspectives of two key groups: consumers and utilities.

In practice, the utility perspective is not necessarily in direct opposition to that of consumers. Nevertheless, the simplified perspectives below may be helpful for illustrating, in general terms, how different aspects of PBR tend to be viewed by the two groups.

Regulators have a unique perspective, in that they must balance the interests of consumers and utilities with the goal of achieving a result that is in the overall public interest. In many cases, regulators are also tasked with considering additional issues such as environmental protection, and additional perspectives such as those of competitive suppliers, third-party vendors and other elements of the electricity industry. We expect regulators would consider both utility and consumer perspectives outlined here, and we offer summaries of the advantages and disadvantages that may be most pertinent to regulators.

Regulators have a unique perspective, in that they must balance the interests of consumers and utilities with the goal of achieving a result that is in the overall public interest.

This chapter is organized into four sections, covering MRPs, PIMs, MRPs versus stand-alone PIMs, and lessons the United States can learn from Great Britain's RIIO approach. Each of these sections discusses advantages and disadvantages from the customers' perspective, followed by the utility's perspective. The organizational structure is displayed in the boxes below.

5.1		MRPs	
Advantages & Disadvantage	5.1.1	Customers' Perspective	
		Overarching Issues	
		Attrition Relief Mechanisms	
Advantages & Disadvantage	5.1.2	Utility's Perspective	
		Overarching Issues	
		Attrition Relief Mechanisms	

5.2		PIMs	
Advantages & Disadvantage	5.2.1	Customers' Perspective	
		Overarching Issues	
		Metrics and Targets	
		Financial Incentives	
Advantages & Disadvantage	5.2.2	Utility's Perspective	
		Overarching Issues	
		Metrics and Targets	
		Financial Incentives	

5.3		MRPs vs. Stand-Alone PIMs	
Advantages & Disadvantage	5.3.1	Customers' Perspective	
		Arguments for Stand-Alone PIMs	
		Arguments for MRPs	
Advantages & Disadvantage	5.3.2	Utility's Perspective	
		Arguments for Stand-Alone PIMs	
		Arguments for MRPs	

5.4		What Can the United States Learn From the British Approach to PBR?	
Advantages & Disadvantage	5.4.1	Customers' Perspective	
		Advantages of RIIO	
		Disadvantages of RIIO	
		Other Approaches to PBR	
Advantages & Disadvantage	5.4.2	Utility's Perspective	
		Advantages of RIIO	
		Disadvantages of RIIO	



5.1. Multi-Year Rate Plans

Multi-year rate plans have been used for decades to provide utilities with strong cost control incentives, while streamlining regulation and facilitating utility innovation and marketing flexibility. However, MRPs can pose risks for utilities as well as for regulators and customers. This section considers both the advantages and disadvantages associated with MRPs in general, and takes a close look at the ARM provisions.

5.1.1 Customers' Perspective

Overarching Issues With MRPs

Advantages of MRPs From the Customers' Perspective

From the perspective of consumers, MRPs can potentially offer a host of benefits, including reduced costs, greater implementation of DERs, and more transparency regarding utility cost performance.

MRPs have the potential to deliver significant cost savings to customers. By capping utilities' allowed revenues and allowing utilities to keep a portion of cost savings, MRPs can provide financial incentives to encourage utilities to undertake a wide range of initiatives to improve performance. In other words, MRPs typically increase regulatory lag (the lag between an increase in a utility's cost and an adjustment to revenue for that cost increase) without sacrificing the timeliness of rate adjustments. These cost control incentives can also help to shift utility financial incentives away from the bias toward capital investments and increasing rate base that exists under COSR.

MRPs can streamline regulation. A widely recognized benefit of MRPs is the potential for fewer rate cases, since MRPs typically span three or more years. Fewer rate cases can free up time for regulators and stakeholders to spend on other important proceedings. In a high DER future, important proceedings are needed on numerous topics including integrated resource planning and the value of distributed solar power. The benefit of regulatory cost savings is greatest in jurisdictions with numerous utilities. In the United States, jurisdictions with four or more investor-owned electric utilities include California, Florida, Indiana, Missouri, New York, Ohio, Pennsylvania, Texas and Wisconsin. Another way that MRPs can reduce costs is by reducing the need for regulatory review of specific utility initiatives or capital expenditures after they have been made, since the MRP strongly incentivizes cost containment.

THE REGULATORS' PERSPECTIVE

Regulator interests frequently overlap with customer and utility interests. Here we highlight several advantages and disadvantages that may be especially pertinent to regulators.

Advantages of MRPs

- Can reduce the frequency of rate cases, freeing up commission resources for other needs
- Can improve the culture of utility management
- Can improve utility performance and lower utility costs
- ARMs used with MRPs typically result in predictable, stable rate increases, relative to rate cases

Disadvantages of MRPs

- Challenging to design ARMs in a way that balances customer and utility interests
- Fewer rate cases means less frequent opportunities to review costs
- Commission may lack resources and skills to effectively review proposals
- Utilities tend to have an advantage in terms of access to information



MRPs can provide financial incentives to encourage utilities to undertake a wide range of initiatives to improve performance. In other words, MRPs typically increase regulatory lag (the lag between an increase in a utility's cost and an adjustment to revenue for that cost increase) without sacrificing the timeliness of rate adjustments. These cost control incentives can also help to shift utility financial incentives away from the bias toward capital investments and increasing rate base that exists under COSR.

MRPs can change the culture of utility management by creating an increased focus on opportunities to reduce cost and improve long-term performance, as well as an increased awareness of how their performance compares to those of peer utilities. This cultural change could ultimately benefit consumers through improved utility performance.

Several MRP design options can ensure that the cost savings stemming from improved utility performance are shared between utilities and their customers. These options include earnings sharing mechanisms, the occasional rate cases, and the stretch factor provisions of ARMs.

Another benefit of MRPs is that they can be used to encourage the implementation of cost-effective DERs. To achieve this benefit, MRPs must be properly and comprehensively designed to: (a) strengthen the utility's incentive to contain capital expenditures; (b) include revenue regulation to offset a utility's throughput incentive; (c) allow for timely recovery of utility DER-related costs (such as energy efficiency and demand response program costs and distributed generation integration costs); and (d) include DER-focused PIMs.

The issues and information regarding utility cost efficiency and productivity growth which frequently arise in MRP proceedings can assist regulators and stakeholders in better understanding and overseeing utility performance and behavior. Regulators can use that information to better ensure that rates reflect normal or superior levels of operating efficiency.

MRPs can be adopted in stages to gradually build experience, reducing regulatory risk. For example, a number of U.S. regulators have recently experimented with plans with only two- or three-year terms. Simplified approaches to ARM design are also available.

Disadvantages of MRPs From the Customers' Perspective

Despite these benefits, MRPs present several potential drawbacks. For example, there is a risk that an MRP will result in a utility's revenues exceeding its costs for extended periods of time. While such an outcome might be accompanied by improvements in long-term performance and cost reductions, some customers (and regulators) may be reluctant to accept this risk.

Despite these benefits, MRPs present several potential drawbacks.

The risk of an adverse outcome may be particularly acute where regulators and consumer advocates lack the expertise and funding that are needed to advocate effectively on technical MRP design issues.



Utilities, on the other hand, have funding to obtain the requisite expertise, thereby creating a risk of “regulatory capture” of the MRP process by utilities.

Another issue of concern is that MRPs typically produce steady (i.e., annual) increases in customer base rates, unlike COSR where customer base rates do not increase between rate cases. Although there are several mechanisms that can help protect consumers under an MRP — such as earnings sharing mechanisms, off ramps, consumer dividends and shorter rate plan periods — most of these mechanisms weaken the key incentives provided by MRPs to increase efficiencies and reduce costs.

MRPs typically result in less frequent rate cases. While this may be considered an advantage in terms of streamlining regulation, it may also be considered a disadvantage by consumer advocates (and regulators) who prefer to investigate utility costs and rates on a more frequent basis. In addition, less frequent rate cases can increase the regulatory costs of the rate cases that do occur. This may be necessary to allow for thorough review of proposals for ARMs, cost trackers, ESMs and other MRP provisions.

Attrition Relief Mechanisms

Advantages of ARMs From the Customers’ Perspective

ARMs are an important source of stronger performance incentives in MRPs. Well-designed index-based ARMs can provide customers with the benefits of productivity growth that exceeds industry standards. External productivity growth standards can simulate competitive market pressures and foster better utility management. Forecast-based ARMs allow more regulatory guidance prior to investments by utilizing a forecast of specific capital expenditures.

Forecast-based ARMs can include expenditures needed to support DERs (e.g., distribution grid investments needed to support distributed generation). This could significantly encourage the implementation of DERs by providing regulatory guidance and approval for these investments.

Disadvantages of ARMs From the Customers’ Perspective

ARMs are one of the most challenging aspects of an MRP to design in a way that balances the interests of customers and utilities, since regulators and other stakeholders do not have perfect information regarding the utility’s efficient level of costs. This is true for both index-based and forecast-based ARMs, for the reasons described below.

Index-based ARMs are typically constructed using estimates of productivity trends for utility peer groups. It can be challenging to identify a set of peers that experienced capital expenditure needs and other cost pressures in a recent historical period that match those that the subject utility will face prospectively. In addition, productivity research can be opaque and complex, and the large dollar stakes encourage controversy. The regulatory cost of developing an index-based ARM can therefore be considerable.

Well-designed index-based ARMs can provide customers with the benefits of productivity growth that exceeds industry standards.

Forecast-based ARMs allow more regulatory guidance prior to investments by utilizing a forecast of specific capital expenditures.



On the other hand, the cost of developing an index-based ARM can be lower than that of developing forecast-based ARMs. Several regulators have grappled with these issues, yielding a fairly narrow range of approved productivity growth targets in North American proceedings. Simplified approaches to X factor calculation such as the “Kahn method” used by FERC in interstate pipeline proceedings are available.⁵⁸

Index-based ARMs cannot easily accommodate occasional, large capital spending surges such as replacement of customer information systems or a system-wide buildout of advanced metering infrastructure. Thus, the utility might postpone some investments that would be beneficial to customers. Capital cost trackers can remedy this problem, but these trackers reduce incentives to contain costs and can pose risks to customers. Furthermore, regulators and consumer advocates are often uncomfortable signing off on proposals for such large capital spending surges in the context of an ARM, and in the absence of a rate case.

Forecast-based ARMs require a broad review of future costs, including capital expenditures and operating costs, and these are hard to predict in an era of aging assets and technological change. Utilities generally have the advantage of information and resources. The scope of required forecasts can be reduced by escalating the budgets for some costs using formulas.

Forecast-based ARMs mean that future capital expenditures in the cost forecast are effectively preapproved.⁵⁹ This represents a fundamental change in regulatory responsibility for some states and shifts some investment decision risk to customers. Regulators and stakeholders will need sufficient resources, capabilities, and regulatory processes to sufficiently review the cost forecasts in order to protect customers.

Forecast-based ARMs mean that future capital expenditures in the cost forecast are effectively preapproved.

Proceedings to approve forecast-based ARMs can be controversial and contentious. Some remedies for this problem, such as earnings sharing mechanisms and the return to customers of capex underspends, weaken cost containment incentives. Another remedy, extensive commission use of engineering and statistical cost research, involves high regulatory cost. Table 5 summarizes the advantages and disadvantages of MRPs from the customers’ perspective.

⁵⁸ The Kahn method calculates X factors based on cost trends and does not require calculation of input price and productivity indexes. See FERC (2015), Notice of Inquiry, *Five Year Review of the Oil Pipeline Index*, Docket No. RM15-20-000, June 30.

⁵⁹ Utilities would still be at risk for how they performed with regard to the development of the approved capital project, particularly the ultimate cost of developing the project.



Table 5. Multi-Year Rate Plans From the Customers’ Perspective

Advantages	<p>Improved utility performance and lower utility costs</p> <p>Benefits can be shared with customers</p> <p>Less frequent rate cases may permit more attention to other important issues</p> <p>May improve information transparency regarding utility performance</p> <p>Can encourage implementation of cost-effective DERs</p> <p>Can be implemented gradually</p>
Disadvantages	<p>Typically results in automatic rate increases</p> <p>Revenue may exceed cost for extended periods</p> <p>Fewer rate cases means less frequent opportunities to review costs</p> <p>ARM design methods can be opaque, complex and controversial</p> <p>Stakeholders may lack resources and skills to effectively protect consumers</p>

5.1.2 Utility’s Perspective

Overarching Issues With MRPs

Advantages of MRPs From the Utility’s Perspective

MRPs provide more opportunities for utilities to bolster earnings from improved cost containment and marketing. Greater marketing flexibility is needed today to retain large customers and satisfy the complex, changing demands of customers. As discussed in Section 2.5, the need for marketing flexibility is growing due to increased competition and technological change. For example, there is an increasing need for utilities to have the flexibility to offer customers products related to electric vehicles, green power, and value-added services that might be provided using new metering and distribution technologies. A utility might, for example, wish to offer new green power options to customers that are considering alternative providers of electricity. Custom packages are already being offered by utilities for green power services to large volume “key account” customers.⁶⁰ A discounted base rate might be offered for electric vehicle charging when the price of gasoline is low. Utilities can take advantage of advanced metering infrastructure to offer more time-sensitive and location-specific rate options. Rate floors for offerings can alleviate concerns about predatory pricing and cross-subsidization.

MRPs permit superior performers to earn superior returns for a sustained period. The improved cost containment and marketing performance that can result from MRPs is especially welcome for utilities facing mounting competition and reduced opportunities for traditional investments.

MRPs permit superior performers to earn superior returns for a sustained period. The improved cost containment and marketing performance that can result from MRPs is especially welcome for utilities facing mounting competition and reduced opportunities for traditional investments.

⁶⁰ See, for example, the Green Rider service of Duke Energy in North Carolina.



By reducing the frequency of rate cases, MRPs can also help utility managers focus on their basic business of providing customer-responsive services cost effectively. The more businesslike corporate culture that MRPs encourage can also help utilities succeed with mergers and acquisitions. Some of the most successful U.S. utility companies, including Duke Energy, NextEra Energy, and MidAmerican Energy, operated for many years without rate cases. Managers who spearhead performance improvements under the spur of stronger incentives have increased advancement prospects. Streamlined regulation is particularly valued by utility companies that operate in multiple jurisdictions. These companies are quite numerous in the United States today.

Utility operating risk may increase under MRPs. Thus, there is less risk of a reduction in the target ROE compared to other forms of alternative regulation, such as cost trackers and revenue decoupling. Utilities that combine proposals for an MRP and revenue decoupling reduce the risk of a reduction in authorized ROE.

Utilities can afford to purchase or develop the in-house expertise needed to develop sound MRP strategies and persuasive testimony. This reduces the likelihood of poor regulatory outcomes. Utilities can learn to master the MRP process much as they currently excel at the rate case process.

Disadvantages of MRPs From the Utility's Perspective

The increased risk of operation under MRPs is unlikely to be matched by an increase in the authorized ROE. One source of risk is that revenue will not always track the occasional surges in utility cost. Another is that MRPs may be designed in such a way that a competitive rate of return is impossible, or that customers receive most benefits of improved performance. Utilities in some countries have sued regulators for their MRP decisions or filed appeals in the court system.⁶¹

Another concern is that MRPs can increase the interest of regulators and consumer advocates in statistical benchmarking and industry productivity growth standards. It is difficult to benchmark performance accurately and establish appropriate productivity growth goals. Benchmarking is especially unwelcome for poorly performing utilities.

Companies that do not own multiple utilities or operate in multiple jurisdictions have less to gain from the streamlining of regulation.

Attrition Relief Mechanisms

Advantages of ARMs From the Utility's Perspective

Utilities benefit from the greater revenue growth predictability that ARMs generally provide. Forecast-based ARMs are the most widely used form of ARMs by U.S. electric utilities today. These ARMs can be tailored to fund anticipated capex surges.

Index-based ARMs have been advocated over the years by several North American energy utilities, as they typically provide reasonable revenue growth when high capex is not anticipated, and they can tailor revenue growth to actual inflation and customer growth.

⁶¹ See ATCO Group (2015); FortisAlberta (2015); Ausgrid, Endeavour Energy, and Essential Energy (2015); and Higgins (2015).



Disadvantages of ARMs From the Utility’s Perspective

It can be difficult to design ARMs that address all cost surges that utilities experience. This is particularly true for index-based ARMs because they increase revenue according to an external index that typically reflects long-term productivity trends. While it may be possible for utilities to obtain supplemental revenue for such surges through capital cost trackers or other means, such requests will be resisted by some stakeholders and may be denied.

Forecast-based ARMs may also provide inadequate revenues for utilities, as it is difficult to accurately forecast costs over a lengthy plan period, and utilities are at risk that costs will exceed even their best cost forecast. In addition, forecast-based ARMs in the United States typically have predetermined “stair-step” trajectories that are insensitive to inflation outcomes. Table 6 summarizes the advantages and disadvantages of MRPs from the utility’s perspective.

Table 6. Multi-Year Rate Plans From the Utility’s Perspective

Advantages	Superior returns for superior performance
	Greater marketing flexibility
	Improved cost containment and marketing can become new earnings driver
	Better performance needed in period of mounting competition
	Better performers more likely to make successful mergers and acquisitions
	Utilities typically have expertise to support their MRP proposals
	Predictable revenue growth
	Streamlined regulation, a particular benefit for companies with multiple utilities
Disadvantages	Operating risk may increase materially
	Corresponding increase in target ROE unlikely
	Difficult to accommodate occasional cost surges
	Greater focus on a utility’s comparative performance

5.2. Performance Incentive Mechanisms

Regulators have used targeted PIMs for many years to address traditional performance areas such as reliability, safety, power plant performance and energy efficiency programs. In recent years, these mechanisms have received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and other less-conventional technologies and practices.

However, PIMs pose risks for utilities as well as for regulators and customers, particularly when financial incentives are applied. This section considers the advantages and disadvantages associated with PIMs from these different perspectives.



5.2.1 Customers' Perspective

Overarching Issues Associated With PIMs

Advantages of PIMs From the Customers' Perspective

Utility performance metrics and incentives can serve as valuable regulatory tools for several reasons. First, PIMs can be targeted to performance areas of special concern to customers, including areas that might not otherwise receive sufficient utility attention. For example, PIMs allow regulators to encourage better utility performance in areas where historical performance has been unsatisfactory. PIMs can also help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.

Second, PIMs help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized or well understood.

Third, PIMs allow regulators to offset or mitigate current financial incentives that create a bias toward capital investments.

Fourth, where utilities are subject to economic and regulatory cost-cutting pressures, PIMs can encourage utilities to maintain, or even improve, customer service, customer satisfaction and other relevant performance areas.

Fifth, well-designed PIMs for DERs can encourage utilities to use DERs cost effectively. Such PIMs create incentives to use DERs to contain the cost of fuel and purchased power. Incentivized cost trackers for fuel and purchased power are difficult to design and rarely used. PIMs for DERs can also help MRPs strengthen incentives to slow rate base growth.

Finally, PIMs can be applied incrementally and gradually over time. Thus, they represent a relatively flexible, low-risk and low-cost regulatory option.

THE REGULATORS' PERSPECTIVE

Regulator interests frequently overlap with customer and utility interests. Here we highlight several advantages and disadvantages that may be especially pertinent to regulators.

Advantages of PIMs

- Can make regulatory goals explicit
- Can encourage better utility performance in areas of concern
- Can help to ensure cost-cutting does not lead to degradation of service or safety
- Relatively low-risk and low-cost option for improving key performance areas

Disadvantages of PIMs

- Design, implementation, and review may be complex, contentious and resource intensive
- May distract regulators and utilities from more important issues
- Design of PIMs may favor utilities, be subject to gaming and manipulation, or lead to unintended consequences
- Important performance areas may be missed because they are not easy to address with PIMs



Disadvantages of PIMs From the Customers' Perspective

PIMs require regulators and stakeholders to identify specific performance areas and quantify the desired outcomes. Regulators and stakeholders might not have the resources and wherewithal to explicitly identify all areas where performance should be improved or to define all desired outcomes.

PIMs can be targeted to performance areas of special concern to customers, including areas that might not otherwise receive sufficient utility attention. For example, PIMs allow regulators to encourage better utility performance in areas where historical performance has been unsatisfactory. PIMs can also help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.

Utilities can exploit information asymmetries and their funding advantages to lobby for terms that are overly favorable to their interests. Many PIMs involve awards for utilities but not penalties.

PIMs may not address some kinds of DER initiatives because load impacts and benefits are hard to measure.

In practice, PIMs tend to focus on areas where it is relatively easy to reach agreement, such as service quality, reliability and conventional energy efficiency programs. More sensitive issues that may matter greatly to customers, including general cost management, are harder to address with PIMs. For example, a PIM is less likely to be proposed and approved for reductions in actual substation cost than for DER-enabled reductions in load that might one day reduce such costs.

The design of PIMs can be quite complex. PIMs can require ongoing regulatory and stakeholder time and resources. It is difficult to establish the right amount of incentive.

Metrics and Targets

Advantages of Metrics and Targets From the Customers' Perspective

Simply establishing performance metrics and targets (without financial repercussions) can provide a low-risk, low-cost means of highlighting and monitoring specific performance areas of interest to customers. Utilities will have an incentive to perform well on the specified performance areas, knowing that regulators and stakeholders are monitoring those areas. In addition, metrics and targets provide information that allows regulators and stakeholders to determine whether financial incentives are warranted for the specified performance areas.

Disadvantages of Metrics and Targets From the Customers' Perspective

Regulatory and stakeholder resources and time may be required upfront to establish the appropriate metrics, targets and reporting requirements. Some resources and time will be required on an ongoing basis to review and respond to periodic reports. The impact of some kinds of DER initiatives on load may be difficult to measure. Furthermore, some metrics and targets might create a distraction from other regulatory issues that warrant more attention from regulators, stakeholders and utilities.



Financial Incentives

Advantages of Financial Incentives From the Customers' Perspective

Financial incentives provide much stronger encouragement than metrics and targets alone for utilities to perform well in the specified performance areas. Financial incentives for customer- and third-party-owned DERs can help offset the bias that utilities have toward capital expenditures.

Financial incentives can also be designed to directly benefit customers. For example, financial penalties can be designed to give money back to affected customers in order to compensate for underperformance in the specified performance area.

Disadvantages of Financial Incentives From the Customers' Perspective

Experience to date has shown that there are many potential pitfalls associated with PIMs.⁶² These pitfalls occur mostly as a result of financial rewards and penalties. Potential pitfalls include:

- *Disproportionate rewards (or penalties).* PIMs can sometimes provide rewards (or penalties) that are too high relative to customer benefits or utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.⁶³
- *Unintended consequences.* Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.
- *Uncertainty.* Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention and are less likely to achieve policy goals. In addition, significant and frequent changes to performance incentive mechanisms create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.
- *Gaming and manipulation.* Every PIM carries the risk that utilities will game the system or manipulate results.

Financial incentives provide much stronger encouragement than metrics and targets alone for utilities to perform well in the specified performance areas.

In most cases, these pitfalls can be managed through sound design and implementation of performance metrics and incentives. They can also be mitigated by ongoing evaluation of and improvements to the incentive mechanisms.

⁶² Whited, Woolf and Napoleon (2015) "Utility Performance Incentive Mechanisms: A Handbook for Regulators."

⁶³ For example, financial rewards or penalties that are tied to the avoided cost of energy will fluctuate significantly according to fuel price or wholesale market price swings, creating great risk of over- or under-compensation.



In addition, significant regulatory and stakeholder resources may be required upfront to establish the appropriate financial incentives. Additional resources are required on an ongoing basis to review and respond to the financial incentives earned by the utility. With significant dollars riding on the outcome, proceedings to design and approve PIMs can be contentious and resource-intensive.

Furthermore, PIMs sometimes provide utilities with financial rewards for performance outcomes that they have an obligation to achieve anyway, in the absence of PIMs. Such PIMs might over-compensate utilities for the performance, to the detriment of customers.⁶⁴

Finally, the regulatory review process associated with financial incentives can be significantly more cumbersome and contentious than the process required for metrics and targets alone, due to the costs and risks to both the utility and customers. Table 7 summarizes the advantages and disadvantages of PIMs from the customers’ perspective.

Table 7. Performance Incentive Mechanisms From the Customers’ Perspective

Advantages	<ul style="list-style-type: none"> Can encourage better utility performance in areas of concern Can make regulatory goals and incentives explicit May help mitigate utility bias toward capital investments Can be designed to directly benefit customers Can help to ensure cost-cutting does not lead to degradation of service or safety PIMs for DERs can be designed to encourage cost-effective DERs Metrics serve as a low-risk and low-cost option for highlighting and monitoring key performance areas
Disadvantages	<ul style="list-style-type: none"> Design, implementation, and review may be complex, contentious and resource intensive May distract regulators, stakeholders, and utilities from more important issues Design of PIMs may favor utilities, be subject to gaming and manipulation, or lead to unintended consequences Incentives may be insufficient to achieve goals Important performance areas may not be addressed

5.2.2 Utility’s Perspective

Overarching Issues Associated With PIMs

Advantages of PIMs From the Utility’s Perspective

PIMs alert utility managers to special concerns of regulators and customers. They can thereby help to keep relationships with regulators and customers on an even keel. Good customer relations are especially useful in an era of increasing competition.

⁶⁴ This point does not necessarily apply to PIMs that require utilities to achieve exemplary performance.



Utility distribution companies have no opportunity today to invest in power generation, and vertically integrated utilities have less opportunity than in the past. Neither kind of utility typically profits from power procurement. Under these conditions, PIMs for DERs provide a valuable opportunity to profit from reduced power supply costs.

Like MRPs, PIMs can provide utilities with new earnings opportunities at a time when traditional opportunities are diminishing.

Like MRPs, PIMs can provide utilities with new earnings opportunities at a time when traditional opportunities are diminishing. Utilities are more likely to be good performers in the targeted areas. Managers are especially likely to respond to PIMs when their income is tied to the outcome.

PIMs involve considerably less operating risk for utilities than MRPs. Some PIMs involve only rewards and no penalties. This treatment is especially common with PIMs for DSM.

Some metrics and targets may require more utility resources and commitment than are warranted for the relevant performance area and serve as a distraction for utility management from core goals. Some metrics are not easy to control. Targets chosen for metrics can be unreasonable.

Disadvantages of PIMs From the Utility's Perspective

The awards available from PIMs are often small because of low award rates and the typically narrow range of performance areas addressed. Some PIMs involve penalties as well as rewards, and many involve only penalties. Metrics chosen are sometimes difficult to control, and targets are sometimes unreasonable. For example, targets may be unduly ratcheted upwards as utility performance improves.

Metrics and Targets

Advantages of Metrics and Targets From the Utility's Perspective

Metrics and targets are necessary to measure utility performance and focus the attention of utility managers.

Disadvantages of Metrics and Targets From the Utility's Perspective

Some metrics and targets may require more utility resources and commitment than are warranted for the relevant performance area and serve as a distraction for utility management from core goals. Some metrics are not easy to control. Targets chosen for metrics can be unreasonable.

Financial Incentives

Advantages of Financial Incentives From the Utility's Perspective

Financial incentives further alert utility managers to key concerns of regulators and customers even if they are small. The impact is magnified when the compensation of managers is tied to realization of metrics. Rewards for good performance can be a welcome source of earnings at a time when earnings growth opportunities are diminishing.



Disadvantages of Financial Incentives From the Utility’s Perspective

Financial incentives can involve undue risk when targets are unreasonable and utilities have limited control over metric outcomes. Penalties also create bad press for utilities. These problems can be mitigated by normalizing metrics, using deadbands, and by averaging results over several years before awards and penalties are determined.

Some PIMs asymmetrically involve penalties but no rewards. This is counter to the workings of competitive markets, where good performance typically results in higher revenue. A “premium” quality product, for example, is so called because it commands a price premium. Thus, good quality should be rewarded, although the reward should be commensurate with customer benefits. Reward and penalty rates can be designed so that the utility is only rewarded for performance that is sufficiently valued by regulators and customers. Symmetrical incentives require that stakeholders apply a balanced approach to the value of performance, because proportionate revenue adjustments potentially apply to good and bad performance. Table 8 summarizes the advantages and disadvantages of PIMs for utilities.

Table 8. Performance Incentive Mechanisms From the Utility’s Perspective

Advantages	Alert utility managers to areas of special concern to customers and regulators Provide new earnings opportunities for utilities Pose lower risk than MRPs Help to maintain good relationships
Disadvantages	Financial rewards may be small Some PIMs involve only penalties Some PIMs may address areas that are largely outside of utility control Targets may be unreasonably difficult to meet May be resource-intensive and distract from core goals

5.3. Multi-Year Rate Plans Versus Stand-Alone PIMs

PBR around the world has chiefly taken the form of multi-year rate plans that include one or more PIMs. PIMs, particularly those related to reliability and service quality, are frequently implemented as part of the package of measures included in an MRP in order to counterbalance the MRP’s strong cost- containment incentives.

The United States was an early innovator in the MRP field, but in recent years has not relied on MRPs as much as other countries such as Australia, Great Britain and Canada. The recent resurgence of interest in PBR in the United States appears to place a priority on adding PIMs to existing regulatory systems rather than adopting MRPs. This resurgence seems due in part to the large number of PIMs in the RIIO approach to regulation and the sizable rewards and penalties that ride on these PIMs. However, the RIIO approach also relies heavily upon MRPs to promote efficient utility operations. Furthermore, the unusually heavy financial incentives are largely due to the fact that there is an MRP.

Compared to MRPs, PIMs are more targeted to specific areas, more flexible, more transparent, and allow for more regulatory and stakeholder guidance on the desired outcomes.



This section of the report considers whether a narrow focus on stand-alone PIMs is warranted, or whether a more comprehensive MRP approach to PBR is a better choice. The issue we address here, then, is not whether PIMs are a good idea, or even whether more are needed, but instead whether they should be adopted to the exclusion of other MRP provisions.

5.3.1 Customers' Perspective

Arguments for Stand-Alone PIMs From the Customers' Perspective

Adding PIMs to a more traditional regulatory system can sometimes make more sense than adopting MRPs. PIMs can be applied incrementally and gradually, with relatively low risk to customers. Compared to MRPs, PIMs are more targeted to specific areas, more flexible, more transparent, and allow for more regulatory and stakeholder guidance on the desired outcomes.

Implementation of MRPs can involve significant controversies, complexities, and risk associated with designing ARMs, cost trackers, efficiency carry-over mechanisms and other plan components. Due to asymmetries, where utilities frequently have more information and resources than regulators and stakeholders, designing MRPs in a way that both provides utilities with sufficient revenues and protects consumers can be challenging, resource intensive and contentious. PIMs offer a simpler way to provide regulatory guidance on targeted aspects of utility performance. While the design of PIMs is also subject to some controversy and complexities, the stakes are generally much lower than in MRP design, and the process may be less contentious.

Instead of focusing on the utility's entire revenue stream, PIMs typically provide relatively small financial rewards or penalties to utilities, resulting in less risk of providing inappropriate financial rewards. In addition, PIMs can be more incrementally and gradually modified with modest improvements based on lessons learned over time, again reducing risks to customers.

PIMs allow regulators and stakeholders to provide much more focused guidance on the areas of performance they wish utilities to attend to. PIMs can be used to specifically identify desired levels of performance regarding the development of different types of DERs, the provision of network support services, environmental performance and more. None of these areas of performance can be specifically guided with MRPs and, in the absence of PIMs, MRPs might provide financial incentives for utilities to ignore or underperform in some of these important areas.

PIMs also provide much more transparency regarding targeted aspects of a utility's performance, relative to MRPs. The use of metrics, targets, reporting, and compliance practices allows regulators and stakeholders to observe exactly how well a utility is performing in the relevant performance area. The reporting can be conducted on a relatively frequent basis — for example, once a year — to provide ongoing information that can enable utilities and regulators to respond to underperformance in a timely way if necessary. MRPs, in the absence of appropriate PIMs, do not provide this type of focus or information on specific performance areas (e.g., customer engagement, network support services).

Multi-year rate plans strengthen utility incentives to undertake a much wider range of actions to improve utility performance, including diverse cost containment strategies.



Unlike MRPs, PIMs do not necessarily require benchmarking or indexing a utility’s performance relative to a peer group of other utilities, thereby avoiding all of the challenges of identifying and analyzing a truly comparable peer group.

Arguments for Multi-Year Rate Plans From the Customers’ Perspective

PIMs typically address a fairly narrow range of concerns, such as reliability and DSM programs. Multi-year rate plans strengthen utility incentives to undertake a much wider range of actions to improve utility performance, including diverse cost containment strategies.

A popular argument for stand-alone PIMs is that they involve lower financial stakes for utilities and their customers. This may be true for performance areas where high stakes are not required to elicit good utility performance, or where modest dollars are ventured experimentally for new performance areas. However, stand-alone PIMs with sufficient incentive power to induce utilities to fully embrace DERs wherever they are an efficient alternative to utility capital expenditures would require sizable stakes.

MRPs are sometimes criticized for the controversies, complexities and risk associated with their design. However, MRPs can materially reduce the frequency of general rate cases and can therefore reduce needless regulatory cost, freeing limited consumer resources to participate more effectively in other proceedings. Moreover, there are analogous means to gradually transition to MRPs, such as starting with two- and three-year rate case moratoria. Learning from experience with MRPs around the world reduces the risk of a bad outcome.

Stand-alone PIMs, in contrast, do not offer the clear prospect of reduced regulatory cost. PIMs designed to encourage DERs to reduce load growth can be complex. In the absence of MRPs, these PIMs must do the “heavy lifting” to provide a positive incentive to contain rate base growth. The most common “shared savings” approach to the design of such PIMs requires, first, an estimate of the energy and capacity savings realized from DERs. An estimate is then needed of the monetary benefits of these savings — i.e., the avoided costs. This is fairly straightforward for tracked costs such as generation and purchased power expenses, but is much more difficult for costs that are fixed in the short run, like those for transmission, distribution and utility-owned generation capacity.

In contrast, under a well-designed MRP that includes revenue regulation, utilities have an incentive to use a wide range of DERs as well as other tactics to contain cost without linking revenue to complicated or narrowly focused avoided cost estimates. The utility can even enjoy cost savings from DER activities of independent DSM agencies or energy service companies and has a stronger incentive to encourage DER activities of third parties. Thus, an MRP may create stronger performance incentives at lower net regulatory cost.

The ability of PIMs to permit regulators to provide focused guidance on areas of special concern is not an absolute benefit.

The ability of PIMs to permit regulators to provide focused guidance on areas of special concern is not an absolute benefit. In designing PIMs, regulators tend to focus on areas of conspicuous controversy and do not always recognize important problems or the most effective means of solving problems.

MRPs need not discourage the monitoring of performance areas that interest regulators. To the contrary, performance metrics are an important part of MRPs, and some metrics (e.g., those for service quality) tend to garner increased attention under MRPs. It



is a plus, not a minus, that the design of MRPs raises interest in issues like the productivity growth and operating efficiency that are implicit in a utility’s cost forecast. These issues are of vital interest to consumers in any regulatory system, and raising them encourages better utility performance. Table 9 summarizes the arguments for stand-alone PIMs versus MRPs from the customers’ perspective.

Table 9. Stand-Alone PIMs Versus MRPs From the Customers’ Perspective

<p>Arguments for Stand-Alone PIMs</p>	<p>Simpler means of providing regulatory guidance than MRPs</p> <p>Lower financial stakes tend to engender less controversy during design</p> <p>Limited financial implications reduce risk for customers</p> <p>Can be implemented gradually</p> <p>Provide highly targeted regulatory guidance on specific performance areas</p> <p>Metrics provide stakeholders with key information for monitoring performance</p> <p>PIMs need not address complicated issues like general cost management</p>
<p>Arguments for MRPs</p>	<p>Stronger cost containment incentives than PIMs</p> <p>May provide stronger, more cost-effective incentives for DERs</p> <p>Financial stakes not necessarily higher than with PIMs</p> <p>Streamlined regulation is especially valuable in jurisdictions with numerous utilities</p> <p>Can also be implemented gradually</p>

5.3.2 Utility’s Perspective

Arguments for Stand-Alone PIMs From the Utility’s Perspective

Stand-alone PIMs can make more sense than MRPs for utilities in a number of circumstances. For example, PIMs may be preferable to MRPs where the current regulatory system yields adequate revenue (due to the use of cost trackers, forward test years or other mechanisms), or where regulators and stakeholders may be resistant to proposals for sweeping change to the traditional regulatory structure.

Stand-alone PIMs may also be preferred where it is difficult for the utility and stakeholders to agree on a compensatory mix of cost trackers and ARMs due, for example, to stakeholder and commission skepticism over a proposed accelerated modernization. Parties may insist that the utility do its own planning and submit to the usual prudence reviews at the time assets become used and useful.

Additionally, stand-alone PIMs may be preferred where there is limited need for marketing flexibility in a utility service area (for example, where there are few price-sensitive, large-load customers or where advanced metering infrastructure has not been installed), or where containing regulatory cost is not a key concern (e.g., where the utility company does not operate in multiple jurisdictions).

Arguments for MRPs From the Utility’s Perspective

MRPs may make more sense for utilities operating under conditions other than those described above. Regulatory cost may be a special concern due to ownership of multiple utilities. Local regulation may be



conducive to movement in this direction due, for example, to experience with forward test years and an adequately funded commission staff.

MRPs are also favored where it is relatively easy for the utility and stakeholders to agree on a set of ARMs and cost trackers due, for example, to a relatively predictable cost trajectory and regulator experience in reviewing costs that merit tracking. Marketing flexibility may be especially important due to price-sensitive loads, interest in EVs and green power, or new rate design and marketing opportunities created by advanced metering infrastructure. Table 10 summarizes the advantages and disadvantages of PIMs vs. MRPs from the utility’s perspective.

Table 10. Stand-Alone PIMs Versus MRPs From the Utility’s Perspective

Arguments for Stand-Alone PIMs	<ul style="list-style-type: none"> Can be implemented without significant regulatory change MRPs may be hard to negotiate More marketing flexibility may not be needed Some utilities enjoy adequate revenues under current regulatory system
Arguments for MRPs	<ul style="list-style-type: none"> Reduces cost of regulating multiple utilities Regulators and stakeholders are amenable to MRPs Costs are relatively predictable Facilitates marketing flexibility Can reduce regulatory cost

5.4. What Can the United States Learn From the British Approach to PBR?

Britain has one of the world’s longest histories with the MRP approach to electric and gas utility regulation. Regulators there have devoted considerable thought to how best to refine MRP methods in each price control review. The new RIIO approach is the outcome of a particularly lengthy review and reflects years of trial and error.

RIIO has been mentioned in a number of recent papers as a promising new model for regulating the “utility of the future.”

RIIO has been mentioned in a number of recent papers as a promising new model for regulating the “utility of the future.”⁶⁵ Appraisal of RIIO in the United States is complicated by the different terms used in Great Britain for regulatory mechanisms (e.g., performance metrics are “outputs”) and by the many differences in the regulatory approach used there. This section considers advantages and disadvantages of RIIO from the perspectives of U.S. utilities and customers.

In general, the RIIO approach offers many advancements in MRP design that may be worth considering in the United States.

⁶⁵ Alvarez, P. (2014); Binz and Mullen (2012); Fox-Penner, Harris, and Hesmondhalgh (2013); Lehr and Paulos (2013).



However, RIIO is a highly complex and expensive approach to MRP design, with considerable risk for both utilities and customers due in part to the eight-year term between rate cases. While certain aspects of RIIO are being discussed in the United States, to date no jurisdiction has expressed an intent to adopt the whole approach.

5.4.1 Customers' Perspective

Advantages of RIIO From the Customers' Perspective

The following RIIO innovations are especially promising and may offer improvements to current PBR practices in the United States:

- Conversion of multi-year cost forecasts into ARMs with inflation-adjusted revenue trajectories provides utilities with more inflation protection than the “stair-step” ARMs that are popular in U.S. MRPs. This reduces utility risk without weakening performance incentives and can permit an expansion of the plan period.
- Incentive-compatible menus have promise in the design of ARMs and other MRP provisions.
- Ofgem provides extensive funding for independent benchmarking and engineering studies as part of the process to review capital plans and establish appropriate revenue requirements.
- Low-controversy MRP applications are accorded “fast track” treatment, which helps to reduce regulatory cost and allow regulators and stakeholders to focus on more difficult applications.
- Ofgem has used PIMs to address new performance areas, such as the Information Quality Incentive (which seeks to reward utilities for providing accurate cost projections) and distributed generation connections.
- Utilities make payments directly to affected customers for poor service quality.
- Totex budgeting reduces the incentive to grow rate base.

RIIO is an unusually expensive and time-consuming approach to MRP design.

Disadvantages of RIIO From the Customers' Perspective

The RIIO approach also has several potential limitations and disadvantages that should be considered before adopting RIIO practices in the United States, including the following:

- RIIO is an unusually expensive and time-consuming approach to MRP design. This is due in large measure to the use of forecast-based ARMs and eight-year plan terms. Most first-generation RIIO plans for power distributors took 30 months to develop. The high regulatory cost is all the more remarkable in view of the fact that the approval process is not litigated. Ofgem employs approximately 800 staff members. U.S. regulators and stakeholders may lack the resources and experience to undertake such proceedings. It may be risky to trim steps in the review process, such as statistical benchmarking, in order to expedite the process to be more consistent with U.S. regulatory timeframes.



- Requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments and increases the risk of unintended outcomes or extended detrimental effects on consumers.
- Incentive-compatible menus have been rejected three times in Canadian MRP proceedings.⁶⁶
- Since British power distributors do not administer DSM programs, RIIO provides no guidance as to how to design PIMs that encourage utility DSM.

Requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments and increases the risk of unintended outcomes or extended detrimental effects on consumers.

Other Approaches to PBR Are Also Advantageous

Many advances in PBR have been made in North America and other regions that are worthy alternatives to the RIIO approach. For example:

- More economical approaches to ARM design have been developed in North America. Most notably, U.S. economists invented index-based ARMs that take advantage of information on industry cost trends and simulate competitive market outcomes.⁶⁷ Index-based ARMs are now widely used to regulate utilities in Canada, New Zealand and other countries. These can adjust the revenue requirement automatically for customer growth as well as inflation. Other notable U.S. innovations in ARM design include the hybrid approach to ARM design, the “tracker/freeze” approach, and the California practice of repeating the capital expenditures budget established in the forward test year in the out years of an MRP.
- The sample of standardized data on utility operations available in Britain for statistical benchmarking is much smaller than in the United States. For this and other reasons, Ofgem’s statistical methods are rudimentary compared to the best North American and Australian practices.
- North American and Australian regulators have been more energetic in the development of efficiency carry-over mechanisms, although further progress in this field is needed. This is a promising alternative to the eight-year plan periods in RIIO.
- Consumer advocates play a more significant role in North American utility regulation than in Britain.

⁶⁶ Menus were rejected in the Ontario Energy Board’s IRM1 and IRM3 decisions (Ontario Energy Board [2000; 2008]) as well as the Alberta Utilities Commission’s 2012 decision approving PBR for four of the five large energy distributors in the province (Alberta Utilities Commission [2012]). In the OEB’s IRM1 proceeding, the use of a menu was rejected because it added unnecessary complexity. In IRM3, the menu approach was not generally supported by parties and was barely mentioned in the OEB’s decision. The Alberta Utilities Commission rejected the use of a menu because it believed that the proposed menu was poorly calibrated for Alberta utilities and difficult to understand and implement.

⁶⁷ It is also noteworthy that U.S. regulatory economists independently developed the concept of incentive compatible menus. See, for example, Crew and Kleindorfer (1992).



- North America makes extensive use of settlements in ratemaking, and this approach has ready application in MRP design and approval. Several MRPs approved in North America were outlined in settlements. RIIO encourages consultations, but the regulator ultimately chooses the design and the elements of the MRP. Table 11 summarizes advantages and disadvantages of RIIO from the customers' perspective.

Table 11. RIIO Approach From the Customers' Perspective

Advantages of RIIO	<p>Inflation adjustments are superior to “stair-step” ARMs</p> <p>Menu approach encourages utility to reveal its achievable cost</p> <p>“Fast track” treatment reduces regulatory cost</p> <p>PIMs creatively address new performance areas</p> <p>Customers are directly compensated for unsatisfactory performance</p> <p>“Totex” approach reduces bias toward capital expenditures</p>
Disadvantages of RIIO	<p>RIIO is a complex and expensive approach to MRP design</p> <p>Eight-year term increases period between regulatory review of investments</p> <p>Utilities may be hesitant to adopt technologies that were not in revenue forecast</p> <p>Provides no guidance on incentives to invest in energy efficiency</p> <p>MRP design practices in North America and Australia have many advantages</p>

5.4.2 Utility's Perspective

Advantages of RIIO From the Utility's Perspective

For utilities, a key advantage of RIIO relative to MRPs in the United States is the blending of an index-based and forecast-based ARM, as well as the thoughtful balancing of the two. Specifically, the ARM used in RIIO is based primarily on a multi-year cost forecast, but it also includes an inflation adjustment mechanism. This inflation adjustment mechanism provides superior protection to utilities from inflation risk relative to many of the ARMs used in the United States.

Disadvantages of RIIO From the Utility's Perspective

Most U.S. regulators lack experience with MRPs and may not be inclined to adopt a framework as comprehensive and novel as RIIO. At least 20 U.S. states still use historical test years. Many of RIIO's features — such as totex budgeting and eight-year revenue projections — would likely involve too much change for these jurisdictions.

In addition, many regulators lack the budgets for independent engineering and benchmarking studies. Some utilities would, in any event, be concerned about utility regulatory commissions undertaking these studies even if funding were available. Benchmarking is risky, and Ofgem's own cost forecast (not the utility's) is the primary basis for establishing the ARM.



Further, eight-year ARMs do not provide utilities with much flexibility for dealing with unforeseen challenges, even if the ARM is based on a utility’s own forecast. Utilities will likely request supplemental revenue, which regulators may not grant. Thus, from a utility perspective, a RIIO-style MRP may not be desirable. Table 12 summarizes advantages and disadvantages of RIIO from a utility’s perspective.

Table 12. RIIO Approach From the Utility’s Perspective

Advantages of RIIO	ARM accounts for both utility forecast investments and inflation
Disadvantages of RIIO	<p>Eight-year term unlikely to be embraced by regulators with little MRP experience</p> <p>Expenditure forecast set according to regulator’s forecast of efficient expenditures</p> <p>Eight-year term increases risk of underestimating revenue needs</p>



6. A Roadmap for Regulators

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies. In general, discussions of PBR options in a high DER future should evaluate and balance the range of potential MRP and PIM options that might fit any one state.

Table 13 presents a summary of how various PBR options might match different regulatory goals. The left column identifies the performance improvement goals a state might have; the middle column indicates the extent to which regulators and stakeholders are open to making regulatory changes; and the right column indicates the combination of PBR options that might be appropriate for that state.

Table 13. Regulatory Options to Fit Different Contexts and Meet Different Goals

Performance Improvement Goals	Openness to Regulatory Change	PBR Options
None	Low	Maintain current ratemaking practice
Improvement in specific areas	Low	Adopt PIMs for specific areas
General improvement in utility performance Streamlined regulation	Moderate to high	Adopt an MRP
Support for DERs	Low Moderate	Adopt PIMs for DER <i>or</i> revenue regulation Adopt PIMs for DERs <i>and</i> revenue regulation
Support for DERs General improvement in utility performance Streamlined regulation	High	Adopt PIMs for DERs, an MRP and revenue regulation



Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices.

Regulators and stakeholders who would like to promote improvements in utility performance should consider what areas of performance are most in need of improvement and are most critical in a high DER future. If their main concern is to improve performance in specific areas, stand-alone PIMs might be sufficient to address these areas. If they instead seek wide-ranging performance improvements, including better capital cost management, MRPs may be better suited to these goals than PIMs alone.

Regulators and stakeholders who wish to improve performance comprehensively and also focus on specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs. For example, an MRP with revenue decoupling, tracker treatment of DER-related costs, and PIMs related to cost-effective DERs can provide strong encouragement for utilities to support cost-effective DERs.

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies.



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